enerPLUS

THIRD QUARTER REPORT

NINE MONTHS ENDED SEPTEMBER 30, 2012

SELECTED FINANCIAL RESULTS	Three months ended September 30, 2012	2011	Nine months ended September 30, 2012	2011
Financial (000's)				
Funds Flow	$ 134,980	$ 123,262	$ 444,233	$ 416,927
Cash and Stock Dividends	53,394	97,416	247,988	291,179
Net Income	(63,466)	111,321	2,977	408,852
Debt Outstanding – net of cash	1,118,569	734,300	1,118,569	734,300
Capital Spending	166,988	201,266	692,641	520,875
Property and Land Acquisitions	7,277	67,313	63,946	209,946
Divestments	3,112	7,320	55,636	638,108
Debt to Trailing 12 Month Funds Flow	1.9x	1.3x	1.9x	1.3x
Financial per Weighted Average Shares Outstanding				
Funds Flow	$ 0.68	$ 0.68	$ 2.28	$ 2.32
Net Income	(0.32)	0.62	0.02	2.28
Weighted Average Number of Shares Outstanding	197,618	180,266	194,753	179,566
Selected Financial Results per BOE(1)				
Oil & Gas Sales(2)	$ 43.30	$ 46.44	$ 44.10	$ 48.34
Royalties	(8.61)	(8.33)	(8.74)	(8.67)
Commodity Derivative Instruments	1.06	(0.66)	0.11	(1.09)
Operating Costs	(12.32)	(10.90)	(11.00)	(9.87)
G&A and Equity Based Compensation	(3.17)	(2.45)	(2.94)	(2.96)
Interest and Other Expenses	(2.56)	(1.01)	(1.40)	(1.55)
Taxes	0.29	(4.80)	(0.10)	(3.75)
Funds Flow	$ 17.99	$ 18.29	$ 20.03	$ 20.45

SELECTED OPERATING RESULTS	Three months ended September 30, 2012	2011	Nine months ended September 30, 2012	2011
Average Daily Production				
Crude oil (bbls/day)	36,810	29,337	35,807	29,665
NGLs (bbls/day)	3,538	3,295	3,644	3,323
Natural gas (Mcf/day)	247,347	243,675	249,046	250,244
Total (BOE/day)	81,573	73,245	80,959	74,695
% Crude Oil & Natural Gas Liquids	49%	45%	49%	44%
Average Selling Price(2)				
Crude oil (per bbl)	$ 76.41	$ 77.57	$ 78.72	$ 82.01
NGLs (per bbl)	47.81	64.98	54.88	63.89
Natural gas (per Mcf)	2.20	3.73	2.18	3.83
USD/CDN exchange rate	1.00	1.02	1.00	1.02
Net Wells drilled	17	35	70	75

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

SHARE TRADING SUMMARY **For the three months ended September 30, 2012**	**CDN* – ERF** (CDN$)	**U.S.** – ERF** (US$)
High	$ 16.94	$ 17.48
Low	$ 12.41	$ 12.13
Close	$ 16.30	$ 16.61

* TSX and other Canadian trading data combined.

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

2012 DIVIDENDS PER SHARE **Payment Month**	**CDN$**	**US$(1)**
First Quarter Total	$ 0.54	$ 0.54
Second Quarter Total	$ 0.54	$ 0.53
July	$ 0.09	$ 0.09
August	0.09	0.09
September	0.09	0.09
Third Quarter Total	$ 0.27	$ 0.27
Total Year-to-Date	$ 1.35	$ 1.34

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

PRESIDENT'S MESSAGE

Our efforts throughout 2012 have been focused on delivering organic growth through an oil-focused capital spending program and providing a dividend to our shareholders. We continued to deliver on this strategy during the third quarter while maintaining a strong financial position. Our investment in our Bakken crude oil assets in Fort Berthold, North Dakota continues to deliver as we again increased production from this region during the third quarter, growing by 10% to approximately 12,800 BOE/day. With the weakness in natural gas prices and an absence of meaningful capital spending on our Canadian operated natural gas assets, we saw our natural gas production decline. Overall, our production in the third quarter averaged 81,573 BOE/day, up 11% from the same period a year ago and down slightly from the second quarter. Oil and liquids volumes have grown by 24% year-over-year and were up by 1% versus the previous quarter and now represent just under 50% of our total production.

Our natural gas volumes have declined throughout the year primarily due to a lack of capital investment in our Canadian gas assets. We continued to drill wells in the Marcellus with our partners in order to retain leases in the northeast region of Pennsylvania which we believe is one of the best areas within the play. Based upon the drilling activity to date, we expect to have approximately 65% of our core non-operated leases held by production by year-end. We also satisfied the remainder of our carry commitment associated with the original purchase of interests in the Marcellus. With the weak natural gas price environment in 2012 and on-going infrastructure challenges, drilling and tie-in activity has been slower than expected. As a result, the growth in production volumes has been delayed, however this has had little impact on our funds flow due to weak natural gas prices. We continue to expect a slower pace of wells on-stream through the remainder of the year and anticipate exit production to be approximately 10MMcf/day to 20 MMcf/day lower than originally planned. Exit volumes in the Marcellus are now expected to range between 50 MMcf/day – 60 MMcf/day.

We generated funds flow of $135 million ($0.68 per share) during the quarter. While both crude oil and natural gas prices improved slightly quarter over quarter, higher operating costs caused by a number of one-time charges along with fluctuations in the foreign exchange related to our U.S. operations impacted our funds flow. We invested $167 million in capital expenditures on our assets during the quarter, drilling 16.6 net wells with 18.2 net wells brought on-stream with the bulk of this activity again focused on our oil plays. With the reduction in our monthly dividend to $0.09 per share per month and lower capital spending this quarter, our adjusted payout ratio improved to 159% for the quarter.

Net income for the quarter was impacted by impairments in our exploration and evaluation ("E&E") assets. We recorded E&E impairments of approximately $114 million, the majority of which related to leases in West Virginia and Maryland which will expire over the next 12 months where we don't anticipate allocating capital.

We improved our financial flexibility with the sale of our equity investment in Laricina Energy in August for net proceeds of $141 million. We used these proceeds to reduce our debt and ended the quarter with a debt to trailing twelve month funds flow ratio of 1.9 times versus 2.0 times last quarter. We had a total of $307 million drawn on our $1.0 billion credit facility at September 30th. We also recently extended our $1.0 billion credit facility for an additional year with the same terms and pricing.

Subsequent to the quarter, we announced an agreement to sell all of our assets in Manitoba for gross proceeds of approximately $220 million. These assets are currently producing approximately 1,600 bbls/day of crude oil under waterflood with an estimated 8.4 million barrels of estimated proved plus probable reserves. With limited near-term growth potential under our current capital allocation plans, these assets are considered non-core to our long-term business strategy. The proceeds from this sale will be used to reduce our debt levels and will strengthen our balance sheet as we head into 2013. Our September 30, 2012 debt-to-funds flow ratio pro forma this transaction is 1.5 times. We expect to continue selling non-core assets in the future in order to focus our asset base and improve our operational efficiencies. We are also pursuing a joint venture or sale of our early stage gas assets including our Montney and Duvernay lands.

Hedging remains an important element of our business strategy in order to help protect a portion of cash flow to support our growth plans and dividends to investors. We entered into additional hedges on both crude oil and natural gas during the quarter and currently have approximately 58% of our expected 2013 crude oil production, net of royalties, hedged at approximately US$100/bbl. We also have approximately 17% of our expected net natural gas production protected next year at an average floor price of $3.31/Mcf. As we move into the winter months, we may enter into additional natural gas hedges. For the remainder of 2012, we have approximately 63% of our expected crude oil production volumes, net of royalties, hedged at US$96.22/bbl.

Production and Capital Spending

Play Type	Three months ended September 30, 2012 Average Production Volumes	Three months ended September 30, 2012 Capital Spending ($ millions)	Nine months ended September 30, 2012 Average Production Volumes	Nine months ended September 30, 2012 Capital Spending ($ millions)
Tight Oil (BOE/day)	19,322	$ 90	17,760	$ 391
Crude Oil Waterflood (BOE/day)	16,769	25	16,530	95
Conventional Oil (BOE/day)	4,470	13	4,736	27
Total Crude Oil (BOE/day)	40,561	$ 128	39,026	$ 513
Marcellus Shale Gas (Mcfe/day)	40,188	$ 30	35,081	$ 120
Other Natural Gas (Mcfe/day)	205,881	9	216,519	60
Total Gas (Mcfe/day)	246,069	$ 39	251,600	$ 180
Company Total (BOE/day)	81,573	$ 167	80,959	$ 693

Net Drilling Activity – for the three months ended September 30, 2012

Play Type	Horizontal Wells Drilled	Vertical Wells Drilled	Total Wells Drilled	Wells Pending Completion/ Tie-in*	Wells On-stream**	Dry & Abandoned Wells
Tight Oil	7.9	–	7.9	3.6	8.9	–
Crude Oil Waterflood	3.8	–	3.8	1.7	5.9	0.1
Conventional Oil	2.5	–	2.5	0.9	1.7	–
Total Crude Oil	**14.2**	**–**	**14.2**	**6.2**	**16.5**	**0.1**
Marcellus Shale Gas	2.3	–	2.3	2.3	1.7	–
Other Natural Gas	0.1	–	0.1	0.1	–	–
Total Gas	**2.4**	**–**	**2.4**	**2.4**	**1.7**	**–**
Company Total	**16.6**	**–**	**16.6**	**8.6**	**18.2**	**0.1**

* Wells drilled during the quarter that were pending potential completion/tie-in or abandonment.
** Total wells brought on-stream during the quarter regardless of when they were drilled.

UPDATE ON 2012 GUIDANCE

The slower pace of activity in the Marcellus and the corresponding delay in bringing the associated natural gas production on stream is expected to impact both our annual and exit production rates. As a result, we are revising our annual average production guidance from 83,500 BOE/day to 82,000 BOE/day and now expect our exit production could range between 85,000 BOE/day to 88,000 BOE/day. The sale of our Manitoba assets is not expected to have a material impact on our 2012 exit production forecast as the sale is expected to close late in December. Our current production is approximately 84,000 BOE/day. Operating costs are now expected to average $10.70/BOE versus our original expectation of $10.40/BOE due to our revised production forecast. We are maintaining our capital spending guidance of $850 million with the majority of this spending focused on our crude oil properties.

OUTLOOK

Looking forward to 2013, our focus will be on improving the profitability of our business while maintaining our financial strength. We expect to reduce our capital spending program by approximately 20% next year from 2012 levels. As a result, we would expect to see an improvement in our adjusted payout ratio while maintaining an attractive dividend.

Our growth expectations will be reduced for next year due to the lower capital program and the sale of our Manitoba assets (1,600 bbls/day) which is expected to close at the end of 2012. Should profitability improve (for example through commodity price increases or improved operating efficiencies) we would have the ability to increase our capital program and production to capture additional value for our shareholders.

Gordon J. Kerr
President & Chief Executive Officer
Enerplus Corporation

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

The following discussion and analysis of financial results is dated November 8, 2012 and is to be read in conjunction with:

- the audited consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the years ended December 31, 2011 and 2010; and
- the unaudited interim Consolidated Financial Statements of Enerplus as at and for the three and nine months ended September 30, 2012 and 2011, the "Interim Financial Statements".

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 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 and may not be comparable to information produced by other entities.

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A under "Forward-Looking Information and Statements" for further information.

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 IFRS and therefore may not be comparable with the calculation of similar measures by other entities:

"Payout ratio" is used to analyze operating performance, leverage and liquidity. We calculate payout ratio by dividing cash dividends to shareholders by funds flow.

"Adjusted payout ratio" is used to analyze operating performance, leverage and liquidity. We calculate our adjusted payout ratio as cash dividends to shareholders 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

Our production averaged 81,573 BOE/day in the third quarter representing an increase of 11% over the previous year. Our crude oil and natural gas liquids production also increased approximately 24% over the previous year mainly due to our capital program at our Fort Berthold crude oil property. However our natural gas production is lower than we expected due to tie-in delays on our non-operated Marcellus properties and as a result we are reducing our annual average production guidance to 82,000 BOE/day from 83,500 BOE/day and adjusting our exit rate production guidance to a range of 85,000 BOE/day to 88,000 BOE/day. Given current low natural gas prices these tie-in delays are not expected to materially impact our cash flow in 2012.

Capital spending was in-line with expectations totaling $167.0 million for the third quarter and $692.7 million year-to-date. We continue to manage towards annual capital spending of $850 million. During the quarter we also spent $4.6 million on our Marcellus carry commitment which is now fully satisfied.

Funds flow for the quarter increased by 9% to $135.0 million from $123.3 million in the same quarter of 2011 driven by increased oil revenues along with a decrease in current taxes. G&A and equity based compensation expenses were $3.15/BOE for the quarter and are on track with annual guidance of $3.30/BOE. Operating costs increased to $12.59/BOE for the quarter mainly due to seasonal and non-recurring costs along with mark-to-market losses on our electricity contracts. Although our absolute operating costs are on target with our expectations for the year, we are increasing our annual guidance to $10.70/BOE from $10.40/BOE due to our revised production guidance.

We recorded a net loss of $63.5 million for the quarter as we experienced a non-cash mark-to-market loss of $48.7 million on our commodity hedging contracts due to the improvement in crude oil prices during the quarter. We also recorded non-cash impairments of $113.8 million on our Exploration and Evaluation ("E&E") assets resulting from acreage we intend to let expire.

We have improved our balance sheet and liquidity during the quarter with the sale of our equity interest in Laricina Energy for after tax proceeds of approximately $141.0 million. In addition, subsequent to the quarter we announced an agreement to sell all of our non-core assets in Manitoba for gross proceeds of approximately $220 million and we extended our $1.0 billion credit facility by a year to October 31, 2015 with the same commercial terms and pricing.

RESULTS OF OPERATIONS

Production

Production in the third quarter of 2012 was 81,573 BOE/day, slightly down from our second quarter production of 82,108 BOE/day. Our crude oil production is in-line with expectations however our natural gas production was lower than anticipated as tie-in activity on our non-operated interests in the Marcellus has been slower than expected. Although the growth in production volumes has been delayed, the cash flow impact for 2012 is modest given the current low natural gas price environment. We continue to expect a slower pace of on-streams for the remainder of 2012 and anticipate exit production to be 10 MMcf/day to 20 MMcf/day lower than originally planned.

Compared to the third quarter of 2011, production increased 11% or 8,328 BOE/day with the majority coming from our crude oil property in Fort Berthold. Our natural gas volumes were relatively flat year over year as increased volumes from our Marcellus assets offset expected production declines on our conventional natural gas assets in Canada.

Our weighting of crude oil and liquids production was 49% in the third quarter, up from 45% in the third quarter of 2011. We continue to expect a crude oil and liquids weighting of approximately 50% as we exit 2012.

Average daily production volumes for the three and nine months ended September 30, 2012 and 2011 are outlined below:

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2012**	**2011**	**% Change**	**2012**	**2011**	**% Change**
Crude oil (bbls/day)	36,810	29,337	25%	35,807	29,665	21%
Natural gas liquids (bbls/day)	3,538	3,295	7%	3,644	3,323	10%
Natural gas (Mcf/day)	247,347	243,675	2%	249,046	250,244	–%
Total daily sales (BOE/day)	81,573	73,245	11%	80,959	74,695	8%

We are reducing our annual average production guidance to 82,000 BOE/day from 83,500 BOE/day and adjusting our exit rate guidance to a range of 85,000 BOE/day to 88,000 BOE/day given the tie-in delays we are experiencing in the Marcellus. It is important to note this reduction is due to lower natural gas production estimates and we are not changing our forecasts with respect to crude oil and natural gas liquids production. Our 2012 guidance has not been adjusted for the Manitoba disposition as it is expected to close near the end of 2012. Our guidance does not contemplate any further acquisition or disposition of producing assets.

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 our average selling prices for the three and nine months ended September 30, 2012 and 2011. It also compares the benchmark price indices for the same periods.

	Three months ended September 30,			Nine months ended September 30,		
Average Selling Price(1)	**2012**	**2011**	**% Change**	**2012**	**2011**	**% Change**
Crude oil (per bbl)	$ 76.41	$ 77.57	(1)%	$ 78.72	$ 82.01	(4)%
Natural gas liquids (per bbl)	47.81	64.98	(26)%	54.88	63.89	(14)%
Natural gas (per Mcf)	2.20	3.73	(41)%	2.18	3.83	(43)%
Per BOE	43.30	46.44	(7)%	44.10	48.35	(9)%

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

	Three months ended September 30,			Nine months ended September 30,		
Average Benchmark Pricing	**2012**	**2011**	**% Change**	**2012**	**2011**	**% Change**
WTI crude oil (US$/bbl)	$ 92.22	$ 89.76	3%	$ 96.21	$ 95.48	1%
WTI crude oil CDN$ equivalent (CDN$/bbl)	92.22	87.97	5%	96.21	93.57	3%
AECO natural gas – monthly index (CDN$/Mcf)	2.19	3.72	(41)%	2.18	3.74	(42)%
AECO natural gas – daily index (CDN$/Mcf)	2.29	3.66	(37)%	2.11	3.77	(44)%
NYMEX natural gas – monthly NX3 index (US$/Mcf)	2.81	4.19	(33)%	2.62	4.23	(38)%
NYMEX natural gas – monthly NX3 index CDN$ equivalent (CDN$/Mcf)	2.81	4.11	(32)%	2.62	4.15	(37)%
USD/CDN exchange rate	1.00	0.98	2%	1.00	0.98	2%

	Nine months ended September 30,								
Average Differentials (US$/bbl or US$/Mcf)	**2012**	**2011**	**Q3 2012**	**Q2 2012**	**Q1 2012**	**Q4 2011**	**Q3 2011**	**Q2 2011**	**Q1 2011**
MSW Edmonton – WTI	$ (9.27)	$ 1.29	$ (7.21)	$ (10.12)	$ (10.49)	$ 1.43	$ 4.21	$ 4.35	$ (4.69)
WCS Hardisty – WTI	(22.00)	(19.37)	(21.72)	(22.87)	(21.42)	(10.48)	(17.62)	(17.64)	(22.86)
Brent Futures (ICE) – WTI	16.00	16.01	17.22	15.38	15.40	14.88	22.35	14.61	11.06
AECO monthly – NYMEX	(0.41)	(0.38)	(0.60)	(0.40)	(0.23)	(0.16)	(0.39)	(0.45)	(0.28)

CRUDE OIL AND NATURAL GAS LIQUIDS

West Texas Intermediate ("WTI") crude oil prices recovered during the third quarter of 2012 after pulling back during the second quarter due to macroeconomic uncertainty. Refinery demand picked up considerably due to seasonal demand factors and lower available capacity. The pricing of WTI remained discounted relative to Brent. Canadian and U.S. Bakken light sweet differentials remain fairly wide, however they are starting to narrow as the industry adds more rail capacity to the region.

The average price received for our crude oil (net of transportation) in the third quarter of 2012 decreased slightly to $76.41/bbl from $77.57/bbl in the third quarter of 2011. For the nine months ended September 30, 2012 our realized crude oil price (net of transportation costs) decreased 4% to $78.72/bbl from $82.01/bbl during the same period in 2011. Differentials for both light sweet and heavy crude oil production, both in Canada and the U.S., have been significantly wider in 2012 compared to 2011, due to a combination of increased supply and numerous pipeline and refinery issues. The wider differentials have led to lower realized prices relative to benchmark WTI pricing in both the three and nine month periods in 2012.

Our realized price for natural gas liquids decreased by 26% to $47.81/bbl from $64.98/bbl in the third quarter compared to the same quarter of 2011. Year-to-date our natural gas liquids realized $54.88/bbl, a decrease of 14% compared to $63.89/bbl in the previous year. The decreases reflect an excess supply of propane and butane in the market in 2012 which represents approximately 65% of our natural gas liquids production.

NATURAL GAS

Natural gas prices remained weak during the third quarter of 2012 although we did see some price recovery near the end of the quarter as we head into fall and winter. The year-over-year storage surplus has been drastically reduced throughout the summer due to increased demand for power generation along with warmer than normal summer temperatures. Storage will likely finish the injection season at record levels but is no longer at risk of encountering widespread congestion issues. U.S. gas drilling rig counts are down over 50% from 2011 due to challenging dry gas economics which is helping to level off U.S. natural gas production after many years of growth. Our outlook is for a more balanced market in 2013 after being oversupplied during 2012.

For the three months ended September 30, 2012 we sold our natural gas for an average price of $2.20/Mcf (net of transportation costs) which represented a 41% decline from the prices received during the same period of 2011. This decrease was in line with the decrease in the monthly AECO index but was larger than the change in both the AECO daily and NYMEX indices. Our lower realized prices include losses associated with physical fixed price positions that we took at the beginning of the summer gas season.

For the nine months ended September 30, 2012 our average realized natural gas price was $2.18/Mcf (net of transportation costs), a 43% decrease from $3.83/Mcf during the same period in 2011. This decrease was in line with the changes in the AECO indices.

Price Risk Management

We have a price risk management program that considers our overall financial position, the economics of our capital program and potential acquisitions. Consideration is also given to the cost of our risk management program as we seek to limit our exposure to price downturns. See Note 14 for further information regarding our current price risk management positions.

We have continued to add crude oil and natural gas hedge positions for 2013. As of October 25, 2012 we have swapped 17,000 bbls/day at US$100.84/bbl, which represents approximately 58% of our forecasted net oil production after royalties for 2013. On our natural gas production we have floor protection on 32,200 Mcf/day at $3.31/Mcf before premiums, representing approximately 17% of our forecasted natural gas production after royalties for 2013. In addition, we have fixed price physical natural gas contracts that are listed in Note 14.

The following is a summary of our financial contracts in place at October 25, 2012 expressed as a percentage of our anticipated net production volumes:

	Crude Oil (US$/bbl)(1)(2)		Natural Gas(1) (CDN$/Mcf)
	October 1, 2012 – December 31, 2012	**January 1, 2013 – December 31, 2013**	**January 1, 2013 – December 31, 2013**
Purchased Puts (floor prices)	$ 103.00	–	$ 3.17
%	3%	–	12%
Sold Puts (limiting downside protection)	$ 65.00	$ 63.33	–
%	7%	15%	–
Swaps (fixed price)	$ 95.83	$ 100.84	$ 3.65
%	60%	58%	5%
Sold Calls (capped price)	$ 133.00	$ 130.00	–
%	3%	12%	–
Purchased Calls (repurchasing upside)	$ 103.00	$ 104.09	–
%	3%	12%	–
Brent – WTI Spread	$ 13.71	–	–
%	10%	–	–

(1) Based on weighted average price (before premiums), estimated average annual production of 82,000 BOE/day for 2012 and 2013, less royalties of 21%.
(2) The majority of our crude oil positions are priced in relation to WTI.

ACCOUNTING FOR PRICE RISK MANAGEMENT

During the third quarter of 2012 we recorded cash gains of $7.9 million on our crude oil contracts. In comparison, during the third quarter of 2011 we realized cash losses of $4.5 million on crude oil contracts. The cash gains in 2012 were due to contracts which provided floor protection above market prices. The cash losses in 2011 were a result of crude oil prices rising above our fixed price swap positions.

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. During the third quarter of 2012 forecast crude oil prices increased which resulted in the fair value of our oil contracts decreasing to $53.7 million at September 30, 2012. The change in the fair value of our commodity contracts for the three and nine months ended September 30, 2012 represented an unrealized loss of $48.7 million and an unrealized gain of $71.9 million, respectively. See Note 14 for details.

The following table summarizes the effects of our risk management gains and losses:

Risk Management Gains/(Losses) ($ millions, except per unit amounts)	**Three months ended September 30, 2012**		**Three months ended September 30, 2011**	
Cash gains/(losses):				
Crude Oil	$ 7.9	$ 2.34/bbl	$ (4.5)	$ (1.67)/bbl
Natural Gas	–	$ – /Mcf	–	$ – /Mcf
Total cash gains/(losses)	$ 7.9	$ 1.06/BOE	$ (4.5)	$ (0.67)/BOE
Non-cash gains/(losses) on financial contracts:				
Change in fair value – crude oil	$ (47.3)	$ (13.98)/bbl	$ 121.6	$ 45.05/bbl
Change in fair value – natural gas	(1.4)	$ (0.06)/Mcf	–	$ – /Mcf
Total non-cash gains/(losses)	$ (48.7)	$ (6.49)/BOE	$ 121.6	$ 18.05/BOE
Total gains/(losses)	$ (40.8)	$ (5.43)/BOE	$ 117.1	$ 17.38/BOE

Risk Management Gains/(Losses) ($ millions, except per unit amounts)	**Nine months ended September 30, 2012**		**Nine months ended September 30, 2011**	
Cash gains/(losses):				
Crude Oil	$ 2.3	$ 0.23/bbl	$ (35.5)	$ (4.38)/bbl
Natural Gas	–	$ – /Mcf	13.3	$ 0.19/Mcf
Total cash gains/(losses)	$ 2.3	$ 0.11/BOE	$ (22.2)	$ (1.09)/BOE
Non-cash gains/(losses) on financial contracts:				
Change in fair value – crude oil	$ 73.3	$ 7.47/bbl	$ 127.6	$ 15.76/bbl
Change in fair value – natural gas	(1.4)	$ (0.02)/Mcf	(12.6)	$ (0.18)/Mcf
Total non-cash gains/(losses)	$ 71.9	$ 3.24/BOE	$ 115.0	$ 5.64/BOE
Total gains/(losses)	$ 74.2	$ 3.35/BOE	$ 92.8	$ 4.55/BOE

Revenues

Crude oil and natural gas revenues for the third quarter of 2012 were $324.9 million ($331.7 million, net of $6.8 million of transportation costs), an increase of $12.0 million compared to $312.9 million ($317.7 million, net of $4.8 million of transportation costs) for the third quarter of 2011. Crude oil and natural gas revenues for the nine months ended September 30, 2012 were $978.3 million ($998.1 million, net of $19.8 million of transportation costs), a decrease of $7.5 million compared to $985.8 million ($1,001.2 million, net of $15.4 million of transportation costs) for the same period in 2011. Our crude oil revenues have increased due to higher production levels partially offset by lower realized prices. Natural gas and natural gas liquids revenues have decreased primarily as a result of lower realized prices.

Analysis of Sales Revenue[1] ($ millions)	**Crude oil**	**NGLs**	**Natural Gas**	**Total**
Three months ended September 30, 2011	$ 209.2	$ 19.7	$ 84.0	$ 312.9
Price variance	(3.9)	(5.6)	(34.7)	(44.2)
Volume variance	53.4	1.5	1.3	56.2
Three months ended September 30, 2012	$ 258.7	$ 15.6	$ 50.6	$ 324.9

($ millions)	**Crude oil**	**NGLs**	**Natural Gas**	**Total**
Nine months ended September 30, 2011	$ 664.1	$ 57.9	$ 263.8	$ 985.8
Price variance	(32.3)	(8.9)	(112.3)	(153.5)
Volume variance	140.5	5.8	(0.3)	146.0
Nine months ended September 30, 2012	$ 772.3	$ 54.8	$ 151.2	$ 978.3

(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, 2012 royalties were $64.6 million and $193.8 million respectively, compared to $56.1 million and $176.9 million for the same periods of 2011. As a percentage of oil and gas sales, net of transportation costs, royalties were 20% for the three and nine months ended September 30, 2012 compared to 18% in the same periods in 2011. The royalty rate increase is primarily due to an increased proportion of U.S. production where royalty rates are generally higher than those on our Canadian production. We continue to expect an average royalty rate of approximately 21% in 2012.

Operating Expenses

Our operating expenses were $94.5 million for the third quarter of 2012, an increase of $14.0 million from the second quarter of 2012. The third quarter included approximately $10.8 million of charges that we consider to be seasonal or non-routine in nature. These include a newly enacted annual State impact fee on our Pennsylvania wells, one-time charges for upgrading U.S. Bakken facilities for emissions control, costs for a pipeline repair at our Giltedge property, non-operated equalization charges related to prior years, annual property tax payments and non-cash mark-to-market losses on our electricity contracts. As a result we expect operating costs to moderate from these levels during the fourth quarter.

Operating expenses were $94.5 million or $12.59/BOE for the third quarter of 2012 and $247.1 million or $11.14/BOE for the nine months ended September 30, 2012. In comparison, we had operating costs of $73.6 million ($10.92/BOE) and $198.2 million ($9.72/BOE) for the same periods during 2011. We have had higher well servicing and repairs and maintenance costs in the first nine months of 2012 compared to the same period in 2011 when weather delayed similar work until the fourth quarter of 2011. Our 2012 operating costs also include non-cash mark-to-market losses on our electricity contracts of $3.2 million compared to gains of $3.1 million in 2011 which contributed to the year over year change.

Although our aggregate operating costs are still on target for the year, we are increasing our per BOE annual guidance to $10.70/BOE from $10.40/BOE due to our revised production guidance.

Netbacks

The following tables outline our crude oil and natural gas netbacks for the three and nine months ended September 30, 2012 and 2011. 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.

	Three months ended September 30, 2012		
	Crude Oil	Natural Gas	Total
Average daily production	40,561 BOE/day	246,069 Mcfe/day	81,573 BOE/day
Netback(1)	(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 hedging 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

	Three months ended September 30, 2011		
	Crude Oil	Natural Gas	Total
Average daily production	32,711 BOE/day	243,202 Mcfe/day	73,245 BOE/day
Netback(1)	(per BOE)	(per Mcfe)	(per BOE)
Revenue(2)	$ 71.38	$ 4.39	$ 46.44
Royalties	(15.32)	(0.45)	(8.33)
Cash operating costs	(12.06)	(1.66)	(10.90)
Netback before hedging	$ 44.00	$ 2.28	$ 27.21
Cash hedging gains/(losses)	(1.49)	–	(0.66)
Netback after hedging	$ 42.51	$ 2.28	$ 26.55
Netback before hedging ($ millions)	$ 132.4	$ 51.0	$ 183.4
Netback after hedging ($ millions)	$ 127.9	$ 51.0	$ 178.9

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

	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)	(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 hedging 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

	Nine months ended September 30, 2011		
	Crude Oil	Natural Gas	Total
Average daily production	32,745 BOE/day	251,702 Mcfe/day	74,695 BOE/day
Netback(1)	(per BOE)	(per Mcfe)	(per BOE)
Revenue(2)	$ 75.77	$ 4.49	$ 48.34
Royalties	(15.61)	(0.54)	(8.67)
Cash operating costs	(11.16)	(1.47)	(9.87)
Netback before hedging	$ 49.00	$ 2.48	$ 29.80
Cash hedging gains/(losses)	(3.97)	0.19	(1.09)
Netback after hedging	$ 45.03	$ 2.67	$ 28.71
Netback before hedging ($ millions)	$ 437.6	$ 170.0	$ 607.6
Netback after hedging ($ millions)	$ 402.1	$ 183.3	$ 585.4

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

Our crude oil properties accounted for 87% of our corporate netback before hedging for the first nine months of 2012 compared to 72% for the same period in 2011. Crude oil netbacks per BOE for the three and nine months ended September 30, 2012 are similar to 2011 as cash hedging gains were sufficient to offset lower realized crude oil prices and higher operating costs. Natural gas netbacks per Mcfe have decreased for the same periods due to lower realized natural gas prices and lower hedging gains.

General and Administrative ("G&A") and Equity Based Compensation Expenses

G&A expenses during the third quarter of 2012 were $18.6 million or $2.48/BOE compared to $15.3 million or $2.27/BOE in the third quarter of 2011. G&A expenses for the nine months ended September 30, 2012 were $59.9 million or $2.70/BOE compared to $49.6 million or $2.43/BOE for the same period during 2011. G&A expenses have increased during 2012 primarily due to expanding our U.S. operations as well as higher professional and legal fees in 2012.

Equity based compensation expense includes charges related to our long-term incentive plans ("LTI plans") and our stock option plan (see Note 13 for further details). The costs of our LTI plans can fluctuate from period to period as they are dependent on our share price. Our LTI costs were higher in the third quarter of 2012 as our share price increased 25% during the quarter compared to a 15% decrease in our share price during the third quarter of 2011.

We also recorded unrealized gains of $2.7 million and $3.1 million for the three and nine months ended September 30, 2012, respectively, related to the equity swap on our LTI plans that we entered into during the second quarter of 2012.

The following table summarizes our G&A and equity based compensation expenses:

G&A and Equity Based Compensation Expenses ($ millions)	Three months ended September 30, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
G&A	$ 18.6	$ 15.3	$ 59.9	$ 49.6
Equity based compensation:				
LTI plans expense/(recovery) – cash	5.2	1.2	5.4	10.8
LTI plans equity swap loss/(gain) – non-cash	(2.7)	–	(3.1)	–
Stock option plan – non-cash	2.6	2.8	7.7	9.6
	5.1	4.0	10.0	20.4
Total G&A and Equity Based Compensation Expenses	$ 23.7	$ 19.3	$ 69.9	70.0

(Per BOE)	Three months ended September 30, 2012	2011	Nine months ended September 30, 2012	2011
G&A	$ 2.48	$ 2.27	$ 2.70	$ 2.43
Equity based compensation:				
LTI plans expense/(recovery) – cash	0.69	0.18	0.24	0.53
LTI plans equity swap loss/(gain) – non-cash	(0.37)	–	(0.14)	–
Stock option plan – non-cash	0.35	0.42	0.35	0.47
	0.67	0.60	0.45	1.00
Total G&A and Equity Based Compensation Expenses	$ 3.15	$ 2.87	$ 3.15	$ 3.43

We are maintaining our annual guidance for G&A and equity based compensation expenses at $3.30/BOE.

Finance Expense

Interest on our senior notes and bank credit facility for the three and nine months ended September 30, 2012 totaled $14.9 million and $39.1 million respectively, compared to $10.7 million and $35.3 million for the same periods in 2011. Our interest expense has increased in 2012 as a result of higher debt levels.

Non-cash amounts recorded in finance expense include accretion of decommissioning liabilities, amortization of financing fees and premiums, 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 10 for further details.

The following table summarizes the cash and non-cash finance expense:

Finance Expense ($ millions)	Three months ended September 30, 2012	2011	Nine months ended September 30, 2012	2011
Interest on senior notes and bank credit facility	$ 14.9	$ 10.7	$ 39.1	$ 35.3
Non-cash finance expense	4.0	0.1	13.0	7.3
Total Finance Expense	$ 18.9	$ 10.8	$ 52.1	$ 42.6

At September 30, 2012, after including our underlying derivatives, approximately 68% of our debt was based on fixed interest rates while 32% had floating interest rates. In comparison, at September 30, 2011 approximately 55% of our debt was based on fixed interest rates and 45% was floating.

Foreign Exchange

For the three and nine months ended September 30, 2012 we recorded foreign exchange gains of $13.6 million and $18.9 million respectively, compared to foreign exchange losses of $6.2 million and $3.3 million in the same periods in 2011. The majority of our 2012 year-to-date foreign exchange relates to our second quarter CCIRS settlement on our US$175 million senior notes. Upon settlement of the swap we realized a loss of $18.0 million. In addition, we reversed the unrealized loss we had previously recognized which effectively resulted in an unrealized gain of $18.0 million. Unrealized gains or losses also result from the period end revaluation of our U.S. dollar denominated debt. At September 30, 2012 the U.S. dollar weakened relative to both the beginning of the year and the quarter which also contributed to our unrealized gains. See Note 11 for details.

Foreign Exchange ($ millions)	Three months ended September 30, 2012	2011	Nine months ended September 30, 2012	2011
Realized loss/(gain)	$ 4.1	$ (3.9)	$ 10.0	$ 16.4
Unrealized loss/(gain)	(17.7)	10.1	(28.9)	(13.1)
Total Foreign Exchange loss/(gain)	$ (13.6)	$ 6.2	$ (18.9)	$ 3.3

Capital Investment

Capital spending for the third quarter of 2012 totaled $167.0 million compared to $201.3 million for the same period in 2011. During the quarter we continued to focus on our core assets spending $93.1 million on our Fort Berthold crude oil property, $30.3 million on our Marcellus assets and $25.3 million on our crude oil waterflood properties in Canada.

Property and land acquisitions for the three and nine months ended September 30, 2012 totaled $7.3 million and $63.9 million, respectively, compared to $67.3 million and $209.9 million for the same periods in 2011. During the third quarter we spent $2.7 million primarily on additional lands in Fort Berthold along with $4.6 million on our Marcellus carry obligation ($37.0 million year-to-date) which fully satisfied our carry commitment. During the third quarter of 2011 property and land acquisitions included undeveloped land acquisitions in Canada of $31.5 million, $5.6 million on additional undeveloped lands in the Marcellus area and US$30.3 million on our Marcellus carry obligation.

Our total capital investment activity for the three and nine months ended September 30, 2012 and 2011 are outlined below:

	Three months ended September 30,		Nine months ended September 30,	
Capital Investment ($ millions)	**2012**	**2011**	**2012**	**2011**
Capital Spending	$ 167.0	$ 201.3	$ 692.7	$ 520.9
Office Capital	2.7	3.3	8.8	8.3
Sub-total	169.7	204.6	701.5	529.2
Property and Land Acquisitions	7.3	67.3	63.9	209.9
Property Dispositions	(3.1)	(7.3)	(55.6)	(638.1)
Sub-total	4.2	60.0	8.3	(428.2)
Total Net Capital Investment	$ 173.9	$ 264.6	$ 709.8	$ 101.0

We continue to manage towards our annual capital spending guidance of $850 million.

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

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved plus probable reserves. For the three months ended September 30, 2012 DD&A increased to $132.8 million or $17.69/BOE compared to $108.9 million or $16.16/BOE during the same period in 2011. For the nine months ended September 30, 2012 DD&A increased to $379.5 million or $17.11/BOE from $312.5 million or $15.32/BOE during the same period in 2011. The rise in DD&A for the three and nine months ended September 30, 2012 is primarily due to higher production and well costs with respect to our U.S. operations resulting in higher depletion per BOE.

Impairments

We perform impairment tests on our Developed and Producing ("D&P") assets when indicators of impairment are present. Impairment tests are completed on our Cash Generating Units ("CGUs") to determine if their asset carrying values, including goodwill, are impaired. Our impairment test compares the CGU recoverable amount, which is estimated using proved plus probable reserves discounted at 10%, to the CGU carrying value. Calculated impairments are initially allocated to any goodwill carried by the CGU with the remainder recorded against its carrying value. In the third quarter of 2012 we did not record any additional D&P impairments beyond the $86.9 million recorded in the first quarter of 2012 in our Canadian natural gas CGUs which resulted from lower forecast natural gas prices.

Exploration and Evaluation ("E&E") assets are also tested for impairment when there are indicators that suggest their carrying values may exceed their recoverable amount. In the third quarter of 2012 we recorded E&E impairments totaling $113.8 million of which $65.9 million related to Marcellus leases in West Virginia and Maryland representing approximately 40,000 net acres that are set to expire over the next 12 months. We consider these leases to be less prospective than our other Marcellus acreage and we do not plan to further develop or extend the lands given our current outlook for natural gas prices and other opportunities in our portfolio. We also recorded impairments of $47.9 million on our Canadian E&E assets that primarily relate to Saskatchewan Bakken and Deep Gas assets.

Other Assets

Other assets consist of our portfolio of equity investments in other oil and gas companies. During the quarter we sold our shares in Laricina Energy Ltd., which represented the majority of our portfolio, for proceeds of approximately $141.0 million (net of transaction costs) resulting in an economic gain of $86.5 million. For accounting purposes we recognized $38.7 million of this gain upon transition to IFRS when our equity investments were written up to fair value and the remaining $47.8 million of the gain was recorded in net income during this quarter.

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 $579.0 million at September 30, 2012 compared to $563.8 million at December 31, 2011. The majority of this increase relates to the risk-free rate used to calculate the present value of the future cash outflows, which decreased to 2.32% at September 30, 2012 from 2.49% at December 31, 2011. See Note 9 for further information.

Taxes

CURRENT INCOME TAXES

We recorded a current tax recovery of $2.2 million for the three months ended September 30, 2012 compared to $32.3 million expense for the same period in 2011. The majority of our tax expense recorded in the third quarter 2011 related to an adjustment to Alternative Minimum Tax ("AMT") as well as AMT on current period income. Our current tax recovery recorded in the third quarter of 2012 resulted from the E&E impairment charge in the U.S. Our current tax is comprised mainly of 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 are now expecting to pay U.S. AMT between 2 - 3% of our U.S. cash flow in 2012 and 2013. We do not expect to pay material cash taxes in Canada until after 2015 as we have sufficient tax pools to offset our anticipated taxable income prior to that time. These estimates may vary depending on numerous factors, including but not limited to fluctuating commodity prices, production levels, capital spending and acquisition or disposition activity.

DEFERRED INCOME TAXES

We recorded a deferred income tax recovery of $37.2 million for the three months ended September 30, 2012 compared to a $15.5 million expense for the same period in 2011. The decrease in deferred income tax expense primarily relates to the decrease in income from 2011 as well as other non-taxable gains included in income.

Net Income/(Loss)

The third quarter of 2012 resulted in a net loss of $63.5 million or $0.32 per share compared to net income of $111.3 million or $0.62 per share in the third quarter of 2011. In the third quarter of 2012 we had $40.8 million of mark-to-market losses on our commodity derivative instruments compared to a gain of $117.1 million during the same period of 2011. As well we recorded impairments of $113.8 million from the writedown of E&E properties during the third quarter of 2012.

For the nine months ended September 30, 2012 net income was $3.0 million or nil per share compared to $408.9 million or $2.28 per share for the same period in 2011. The decrease in net income compared to the prior year resulted primarily from the $271.9 million gain recorded in 2011 on our Marcellus property disposition as well as $200.7 million of impairments recorded during 2012 that related to the decrease in natural gas prices and the writedown of E&E properties.

Selected Canadian and U.S. Results

The following table provides a geographical analysis of key operating and financial results for the three and nine months ended September 30, 2012 and 2011.

	Three months ended September 30, 2012			Three months ended September 30, 2011		
(CDN$ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	20,249	16,561	36,810	18,646	10,691	29,337
Natural gas liquids (bbls/day)	3,056	482	3,538	3,065	230	3,295
Natural gas (Mcf/day)	193,819	53,528	247,347	215,826	27,849	243,675
Total average daily production (BOE/day)	55,608	25,965	81,573	57,682	15,563	73,245
Pricing(1)						
Crude oil (per bbl)	$ 74.42	$ 78.83	$ 76.41	$ 77.63	$ 77.45	$ 77.57
Natural gas liquids (per bbl)	50.56	30.40	47.81	65.77	54.36	64.98
Natural gas (per Mcf)	1.94	3.14	2.20	3.65	4.32	3.73
Capital Expenditures						
Capital spending	$ 48.4	$ 118.6	$ 167.0	$ 64.8	$ 136.5	$ 201.3
Acquisitions	–	7.3	7.3	31.5	35.8	67.3
Dispositions	(3.0)	(0.1)	(3.1)	2.2	(9.5)	(7.3)
Revenues						
Oil and gas sales(1)	$ 189.3	$ 135.6	$ 324.9	$ 224.5	$ 88.4	$ 312.9
Royalties(2)	(28.0)	(36.6)	(64.6)	(32.7)	(23.4)	(56.1)
Commodity derivative instruments	(40.8)	–	(40.8)	117.1	–	117.1
Expenses						
Operating	$ 79.8	$ 14.7	$ 94.5	$ 63.6	$ 10.0	$ 73.6
G&A and Equity Based Compensation	19.8	3.9	23.7	16.5	2.8	19.3
Depletion, depreciation and amortization	78.6	54.2	132.8	84.2	24.7	108.9
Impairment	47.9	65.9	113.8	–	–	–
Current income taxes	0.2	(2.4)	(2.2)	–	32.3	32.3

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

(CDN$ millions, except per unit amounts)	Nine months ended September 30, 2012 Canada	U.S.	Total	Nine months ended September 30, 2011 Canada	U.S.	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	20,625	15,182	35,807	18,923	10,742	29,665
Natural gas liquids (bbls/day)	3,266	378	3,644	3,169	154	3,323
Natural gas (Mcf/day)	201,625	47,421	249,046	219,446	30,798	250,244
Total average daily production (BOE/day)	57,495	23,464	80,959	58,666	16,029	74,695
Pricing[1]						
Crude oil (per bbl)	$ 76.28	$ 82.02	$ 78.72	$ 80.56	$ 84.56	$ 82.01
Natural gas liquids (per bbl)	57.07	36.03	54.88	64.53	50.73	63.89
Natural gas (per Mcf)	1.99	2.98	2.18	3.67	4.93	3.83
Capital Expenditures						
Capital spending	$ 205.2	$ 487.5	$ 692.7	$ 196.5	$ 324.4	$ 520.9
Acquisitions	13.8	50.1	63.9	91.0	118.9	209.9
Dispositions	(33.7)	(21.9)	(55.6)	(60.7)	(577.4)	(638.1)
Revenues						
Oil and gas sales[1]	$ 594.3	$ 384.0	$ 978.3	$ 694.2	$ 291.6	$ 985.8
Royalties[2]	(92.4)	(101.4)	(193.8)	(104.0)	(72.9)	(176.9)
Commodity derivative instruments	74.3	–	74.3	92.8	–	92.8
Expenses						
Operating	$ 208.2	$ 38.9	$ 247.1	$ 173.1	$ 25.1	$ 198.2
G&A and Equity Based Compensation	58.9	11.0	69.9	61.8	8.2	70.0
Depletion, depreciation and amortization	239.1	140.4	379.5	246.1	66.4	312.5
Impairment	134.8	65.9	200.7	32.4	–	32.4
Current income taxes	0.1	2.2	2.3	–	76.3	76.3

(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 been relatively flat in 2012 as higher production volumes offset the impact of lower realized commodity prices. During 2011 and 2010 the impact of higher crude oil prices was generally offset by the decline in natural gas prices as well as a reduction in production levels due to our disposition activity, resulting in flat oil and gas sales during those periods.

Net income was also affected by fluctuating risk management costs, impairments related to the decrease in natural gas prices, gains on asset dispositions along with changes in tax provisions.

Quarterly Financial Information ($ millions, except per share amounts)		**Oil and Gas Sales[(1)]**		**Net Income/(Loss)**		**Net Income/(Loss) Per Share** Basic		Diluted
2012								
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	$	978.3	$	3.0	$	0.02	$	0.02
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
2010								
Fourth Quarter	$	313.2	$	64.5	$	0.37	$	0.36
Third Quarter		305.5		(136.3)		(0.77)		(0.77)
Second Quarter		318.2		76.5		0.44		0.38
First Quarter		363.3		(184.0)		(1.05)		(1.08)
Total	$	1,300.2	$	(179.3)	$	(1.02)	$	(1.02)

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

LIQUIDITY AND CAPITAL RESOURCES

We continue to manage our balance sheet in the context of the current natural gas price environment and our 2012 capital program. In the first six months of 2012 we completed an equity offering raising net proceeds of $331 million and also closed an approximate $405 million private placement of senior unsecured notes with maturities extending out 12 years. In the third quarter we sold our shares in Laricina Energy for net proceeds of $141 million and realized an economic gain of approximately $86.5 million.

We have also implemented a number of other initiatives to help manage our balance sheet. In the second quarter we replaced our Dividend Reinvestment Program ("DRIP"), which was only available to Canadian shareholders, with a Stock Dividend Program that is available to all shareholders. We are pleased with the current participation rate of approximately 18% and expect this rate to increase over time due to the favorable tax attributes of this program. We also announced a reduction in our monthly dividend from CDN$0.18 per share to CDN$0.09 per share, effective for our July 20, 2012 payment. Given the current commodity price environment this reduction will allow for continued investment in our asset base in a more sustainable manner.

We continue to pursue other measures to support our capital spending activities including the sale or joint venture of our undeveloped land or the sale of non-core producing properties. We have retained advisors with respect to our Duvernay and Montney interests and are actively marketing these assets. Subsequent to the third quarter we entered into an agreement to sell all of our non-core assets in Manitoba for gross proceeds of approximately $220 million.

Total debt at September 30, 2012, including the current portion, was $1,118.6 million compared to $907.1 million at December 31, 2011, representing a $211.5 million increase. Total debt at September 30, 2012 was comprised of $307.3 million of bank indebtedness and $811.3 million of senior notes. Our capital spending, acquisitions and cash dividends have exceeded our cash flow and proceeds realized on our equity issue and equity portfolio sale which has increased our debt balance. We have $692.7 million of available credit on our bank credit facility at September 30, 2012 and a trailing twelve month debt to funds flow ratio of 1.9x.

Our working capital deficiency, excluding cash and current deferred financial assets and credits, was $191.0 million at September 30, 2012, improving by $171.6 million from $362.6 million at December 31, 2011. The change in our working capital deficit resulted from decreased accounts payable balances due to lower capital spending compared to the fourth quarter of 2011 as well as lower dividends payable following the reduction of our monthly dividend. We expect to finance our working capital deficit through funds flow and our bank credit facility.

Our payout ratio, which is calculated as cash dividends divided by funds flow, was 33% for the third quarter of 2012 compared to 79% for the third quarter of 2011. Our adjusted payout ratio, which is calculated as cash dividends plus capital spending and office capital divided by funds flow, was 159% for the third quarter of 2012 compared to 245% for the third quarter of 2011. We continue to expect our payout and adjusted payout ratios to moderate going forward given the reduction in our monthly dividend, our new Stock Dividend Program and forecasted growth in funds flow.

Our key leverage ratios are detailed below:

Financial Leverage and Coverage	September 30, 2012	December 31, 2011
Long-term debt to funds flow (12 month trailing)(1)	1.9 x	1.6 x
Funds flow to interest expense (12 month trailing)(2)	11.8 x	12.2 x
Long-term debt to long-term debt plus equity(1)	26%	22%

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

Subsequent to September 30, 2012 we extended our unsecured, covenant-based, $1.0 billion bank credit facility by a year to October 31, 2015. Drawn and undrawn fees under the facility did not change with the extension and range between 160 and 325 basis points over bankers' acceptance rates. We are currently paying 180 basis points over bankers' acceptance rates, which are trading around 1.3%, for a combined rate of 3.1%.

At September 30, 2012 we were in compliance with our debt covenants. Our bank credit facility and senior note purchase agreements have been filed as material documents on the Company's SEDAR profile at www.sedar.com.

Dividends

During the three and nine months ended September 30, 2012 we reported a total of $53.4 million ($0.27/share) and $248.0 million ($1.26/share) in dividends to our shareholders, of which $8.5 million and $14.0 million respectively, was non-cash and related to our Stock Dividend Program. On June 12, 2012, we announced a reduction in our monthly dividend from CDN$0.18 per share to CDN$0.09 per share, effective for our July 20, 2012 dividend payment. We continue to assess our dividend levels with respect to anticipated funds flow, debt levels, capital spending plans and capital market conditions.

Participation in the Stock Dividend Program is optional allowing our shareholders to continue to receive cash dividends unless they elect to receive stock dividends. Currently we have a participation rate of approximately 18% or $3.0 million per month. As with the DRIP, the Stock Dividend Program 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 2012, a total of 604,000 shares (2011 – 595,000) were issued pursuant to the Stock Dividend Program, resulting in $8.5 million (2011 – $15.4 million) of additional equity for the company. For the nine months ended September 30, 2012, a total of 2,068,000 shares (2011 – 1,934,000) and $34.3 million of additional equity (2011 – $49.7 million) was issued pursuant to the Stock Dividend Program, our former DRIP and the stock option plan. On February 8, 2012 we completed a bought deal equity financing of 14,708,500 common shares at a price of $23.45 per share for gross proceeds of $344.9 million ($330.6 million net of issuance costs). For further details see Note 13.

We had 197,936,000 shares outstanding at September 30, 2012 compared to 180,582,000 shares outstanding at September 30, 2011. We had 181,159,000 shares outstanding at December 31, 2011. The weighted average basic number of shares outstanding for the nine months ended September 30, 2012 was 194,753,000 (2011 – 179,566,000). At October 31, 2012 we had 198,147,000 shares outstanding.

2012 GUIDANCE

A summary of our updated 2012 guidance is below. This guidance does not include any potential acquisitions or divestments.

Summary of 2012 Expectations	Target	Comments
Average annual production	82,000 BOE/day	Decreased from 83,500 BOE/day
Exit rate production	85,000 – 88,000 BOE/day	Changed from 88,000 BOE/day
Capital spending	$850 million	No change
Marcellus carry commitment spending	Nil	Carry commitment fully satisfied at September 30, 2012.
Exit production mix (volumes)	50% natural gas, 50% crude oil and liquids	No change
Average royalty rate (% of gross sales, net of transportation)	21%	No change
Operating costs	$10.70/BOE	Increased from $10.40/BOE due to revised production guidance
G&A and equity based compensation expenses	$3.30/BOE	No change
Average interest and financing costs	6%	No change

INTERNAL CONTROLS AND PROCEDURES

There were no changes in our internal control over financial reporting during the period beginning on July 1, 2012 and ending on September 30, 2012 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 2012 and 2013 average and 2012 exit production volumes and the anticipated production mix; the results from our Fort Berthold drilling program and the timing of related production; future oil and natural gas prices and our commodity risk management programs; future royalty rates on our production; anticipated cash and non-cash G&A and financing expenses; operating costs; capital spending levels in 2012 and its impact on our production levels; the amount of our future abandonment and reclamation costs and decommissioning liabilities; our 2012 U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes; future debt and working capital levels and debt-to-funds-flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; the amount and timing of future cash dividends that we may pay to our shareholders; the amount and timing of future debt and equity issuances and expected use of proceeds therefrom; and the amount and timing of, and use of proceeds from, future asset dispositions, including the sale of our non-core producing assets in Manitoba.*

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 and operating requirements and dividend payments as needed; 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 our MD&A for the year ended December 31, 2011 and under "Risk Factors" in our Annual Information Form for the year ended December 31, 2011 dated March 9, 2012, which are available on our website at www.enerplus.com and on our SEDAR profile at www.sedar.com and which form part of our Form 40-F filed with the SEC on March 9, 2012 available on EDGAR at www.sec.gov.

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.

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	September 30, 2012	December 31, 2011
Assets			
Current assets			
Cash		$ –	$ 5,629
Accounts receivable		127,219	124,806
Deferred financial assets	14	54,878	2,312
Other current		16,757	14,655
		198,854	147,402
Exploration and evaluation assets	4	768,166	874,799
Property, plant and equipment	5	4,535,033	4,332,011
Goodwill		149,717	154,691
Deferred financial assets	14	7,196	6,585
Other assets	7	11,946	207,824
Total Assets		$ 5,670,912	$ 5,723,312
Liabilities			
Current liabilities			
Accounts payable		$ 271,973	$ 422,666
Dividends payable		17,814	32,609
Current portion of long-term debt	8	45,241	46,808
Deferred financial credits	14	20,247	35,711
		355,275	537,794
Long-term debt	8	1,073,328	860,286
Deferred financial credits	14	17,061	31,820
Deferred tax liability		419,493	452,670
Decommissioning liability	9	578,951	563,763
		2,088,833	1,908,539
Total Liabilities		2,444,108	2,446,333
Equity			
Shareholders' capital	13	3,808,418	3,442,364
Contributed surplus	13	33,488	26,910
Accumulated deficit		(524,478)	(279,467)
Accumulated other comprehensive income/(loss)		(90,624)	87,172
		3,226,804	3,276,979
Total Liabilities & Equity		$ 5,670,912	$ 5,723,312

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Income (loss) and Comprehensive Income (loss)

		Three months ended September 30,		Nine months ended September 30,	
(CDN$ thousands) unaudited	Note	2012	2011	2012	2011
Revenues					
Oil and gas sales		$ 331,753	$ 317,761	$ 998,067	$ 1,001,190
Royalties		(64,624)	(56,096)	(193,803)	(176,873)
Commodity derivative instruments gain/(loss)	14	(40,780)	117,103	74,276	92,793
		226,349	378,768	878,540	917,110
Expenses					
Operating		94,482	73,607	247,065	198,198
General and administrative		18,597	15,279	59,970	49,688
Equity based compensation		5,066	4,050	9,963	20,353
Transportation		6,815	4,827	19,775	15,389
Depletion, depreciation and amortization	5	132,780	108,884	379,515	312,480
Impairments	6	113,824	–	200,730	32,394
Foreign exchange	11	(13,609)	6,177	(18,885)	3,297
Finance expense	10	18,923	10,748	52,129	42,589
Asset disposition gain		(47,782)	(3,937)	(71,726)	(302,082)
Other expense/(income)		207	(61)	(63)	(657)
		329,303	219,574	878,473	371,649
Income/(loss) before taxes		(102,954)	159,194	67	545,461
Current tax expense/(recovery)	12	(2,249)	32,333	2,299	76,329
Deferred tax expense/(recovery)	12	(37,239)	15,540	(5,209)	60,280
Net Income/(loss)		$ (63,466)	$ 111,321	$ 2,977	$ 408,852
Other Comprehensive Income					
Change due to marketable securities (net of tax)	7				
Unrealized gains/(losses)		(17,440)	(457)	(68,517)	52,761
Unrealized gains reclassified to net income		(41,956)	–	(41,956)	–
Change in cumulative translation adjustment		(69,070)	117,152	(67,323)	71,034
Other Comprehensive Income/(loss), net of tax		$ (128,466)	116,695	$ (177,796)	$ 123,795
Total Comprehensive Income/(loss)		$ (191,932)	$ 228,016	$ (174,819)	$ 532,647
Net income/(loss) per share					
Basic		$ (0.32)	$ 0.62	$ 0.02	$ 2.28
Diluted		$ (0.32)	$ 0.62	$ 0.02	$ 2.27
Weighted average number of shares outstanding (thousands)	13				
Basic		197,618	180,266	194,753	179,566
Diluted		197,776	180,647	194,944	179,947

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	2012	2011
Shareholders' Capital		
Balance, beginning of year	$ 3,442,364	$ 5,639,380
Reclassification of EELP units	–	44,387
Reclassification of accumulated deficit	–	(2,314,775)
Public offering	330,618	–
Stock Option Plan – cash	1,180	11,184
Stock Option Plan – non cash	1,119	8,526
Dividend Reinvestment Plan	19,150	38,491
Stock Dividend Plan	13,987	–
Balance, end of period	$ 3,808,418	$ 3,427,193
Contributed Surplus		
Balance, beginning of year	$ 26,910	$ 3,795
Reclassification of trust unit rights liability	–	20,156
Stock Option Plan – exercised	(1,119)	(8,526)
Stock Option Plan – expensed	7,697	9,583
Balance, end of period	$ 33,488	$ 25,008
Accumulated Deficit		
Balance, beginning of year	$ (279,467)	$ (2,314,775)
Reclassification to Shareholders' Capital	–	2,314,775
Net income	2,977	408,852
Cash dividends	(234,001)	(291,179)
Stock dividends	(13,987)	–
Balance, end of period	$ (524,478)	$ 117,673
Accumulated other comprehensive income		
Balance, beginning of year	$ 87,172	$ (22)
Changes due to marketable securities (net of tax)		
Unrealized gains/(losses)	(68,673)	52,761
Unrealized gains reclassified to net income	(41,800)	–
Change in cumulative translation adjustment	(67,323)	71,034
Balance, end of period	$ (90,624)	$ 123,773
Total Equity	$ 3,226,804	$ 3,693,647

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Cash Flows

	Three months ended September 30,		Nine months ended September 30,	
(CDN$ thousands) unaudited	2012	2011	2012	2011
Operating Activities				
Net income	$ (63,466)	$ 111,321	$ 2,977	$ 408,852
Non-cash items add/(deduct):				
Depletion, depreciation and amortization	132,780	108,884	379,515	312,480
Impairments	113,824	–	200,730	32,394
Change in fair value of derivative instruments	55,986	(146,811)	(83,400)	(153,698)
Deferred tax expense/(recovery)	(37,239)	15,540	(5,209)	60,280
Foreign exchange loss/(gain) on U.S. dollar debt	(25,370)	31,690	(15,815)	18,567
Accretion expense	3,356	3,450	10,324	10,244
Equity based compensation – stock option plan	2,588	2,805	7,697	9,583
Amortization of debt transaction costs	303	320	1,097	889
Cross currency interest rate swap principal settlement	–	–	18,043	19,418
Asset disposition gain	(47,782)	(3,937)	(71,726)	(302,082)
Funds Flow	134,980	123,262	444,233	416,927
Decommissioning expenditures	(3,396)	(4,937)	(14,406)	(13,108)
Changes in non-cash operating working capital	(12,138)	(32,803)	(84,144)	(22,571)
Cash flow from operating activities	119,446	85,522	345,683	381,248
Financing Activities				
Issuance of shares	–	15,409	350,948	49,675
Cash dividends	(44,850)	(97,416)	(234,001)	(291,179)
Change in bank debt	(15,720)	250,540	(142,691)	30,250
Repayment on senior notes	–	–	(35,623)	(34,248)
Proceeds from senior note issue	–	–	406,088	–
Cross currency interest rate swap principal settlement	–	–	(18,043)	(19,418)
Changes in non-cash financing working capital	55	101	(14,794)	348
Cash flow from financing activities	(60,515)	168,634	311,884	(264,572)
Investing Activities				
Capital expenditures	(169,752)	(204,542)	(701,495)	(529,170)
Property and land acquisitions	(7,277)	(67,313)	(63,946)	(209,946)
Property dispositions	3,112	7,320	25,636	638,108
Sale of equity investment	141,044	–	145,454	–
Changes in non-cash investing working capital	(37,238)	17,874	(71,498)	(12,541)
Cash flow from investing activities	(70,111)	(246,661)	(665,849)	(113,549)
Effect of exchange rate changes on cash	4,005	418	2,653	788
Change in cash	(7,175)	7,913	(5,629)	3,915
Cash, beginning of period	7,175	4,376	5,629	8,374
Cash, end of period	$ –	$ 12,289	$ –	$ 12,289
Supplementary Cash Flow Information				
Cash income taxes paid	$ –	$ 52,958	$ 17,651	$ 53,126
Cash interest paid	$ 3,249	$ 2,959	$ 24,774	$ 28,087

See accompanying notes to the Condensed Consolidated Financial Statements

NOTES

Notes to Consolidated Financial Statements

1. REPORTING ENTITY

These interim condensed consolidated financial statements and notes ("interim Consolidated Financial Statements") present the results of Enerplus Corporation ("Enerplus") including its Canadian and U.S. subsidiaries.

Enerplus is a North American crude oil and natural gas exploration and development company, and 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 8, 2012.

2. BASIS OF PREPARATION

Enerplus' interim Consolidated Financial Statements present its results of operations and financial position under International Financial Reporting Standards ("IFRS") as at and for the three and nine months ended September 30, 2012, including the 2011 comparative periods. They have been prepared in accordance with IAS 34, "Interim Financial Reporting" as issued by the International Accounting Standards Board ("IASB"). 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, 2011. There have been no changes to the use of estimates or judgments since December 31, 2011.

3. SIGNIFICANT ACCOUNTING POLICIES

Enerplus' accounting policies are unchanged from December 31, 2011. There have been no new accounting pronouncements during the period. These interim Consolidated Financial Statements should be read in conjunction with Enerplus' audited Consolidated Financial Statements as of December 31, 2011.

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

Carrying value ($ thousands)	**E&E assets**
At December 31, 2011	$ 874,799
Capital spending and acquisitions	191,765
Dispositions	(23,386)
Transfers to Property, Plant and Equipment	(141,564)
Impairment	(113,824)
Foreign currency translation adjustment	(19,624)
As at September 30, 2012	$ 768,166

As at September 30, 2012 the E&E asset balance of $768,166,000 (December 31, 2011 – $874,799,000) 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)	**D&P assets**	**Office and other**	**Total**
As at December 31, 2011	$ 5,904,859	$ 71,016	$ 5,975,875
Capital spending and acquisitions	564,855	8,821	573,676
Transfers from Exploration and Evaluation	141,564	–	141,564
Change in decommissioning costs (Note 9)	19,217	–	19,217
Dispositions	(8,150)	–	(8,150)
Foreign currency translation adjustment	(64,344)	(319)	(64,663)
As at September 30, 2012	$ 6,558,001	$ 79,518	$ 6,637,519

Accumulated Depletion and Depreciation	D&P assets	Office and other	Total
As at December 31, 2011	$ 1,591,199	$ 52,665	$ 1,643,864
Depletion, Depreciation and Amortization	374,752	4,763	379,515
Impairment expense (Note 6)	86,906	–	86,906
Foreign currency translation adjustment	(7,727)	(72)	(7,799)
As at September 30, 2012	$ 2,045,130	$ 57,356	$ 2,102,486

Net carrying value	D&P assets	Office and other	Total
As at December 31, 2011	$ 4,313,660	$ 18,351	$ 4,332,011
As at September 30, 2012	$ 4,512,871	$ 22,162	$ 4,535,033

6. IMPAIRMENT

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2012	2011	2012	2011
E&E assets	$ 113,824	$ –	$ 113,824	$ –
D&P assets	–	–	86,906	32,394
Impairment expense	$ 113,824	$ –	$ 200,730	$ 32,394

E&E asset impairments recorded for the three and nine months ended September 30, 2012 relate to undeveloped land and assets that management does not intend to develop further. Developed and Producing ("D&P") asset impairments recorded for the nine months ended September 30, 2012 and 2011 relate to natural gas focused cash generating units ("CGUs") and reflect lower forecast natural gas prices at March 31, 2012 and 2011. The estimated recoverable amounts used for impairment testing were based on the respective assets value in use, calculated using proved plus probable reserves discounted at 10%.

7. OTHER ASSETS

Other assets of $11,946,000 (December 31, 2011 – $207,824,000) represent Enerplus' marketable securities portfolio. During the three months ended September 30, 2012 Enerplus sold its shares in Laricina Energy Ltd. for proceeds of $141,044,000 (net of transaction costs) recognizing an economic gain of $86,516,000 and an accounting gain of $47,782,000. Enerplus reversed $41,956,000 net of tax ($47,782,000 before tax) of unrealized gains previously recorded in accumulated other comprehensive income.

For the three and nine months ended September 30, 2012 the change in fair value of these investments represented unrealized losses of $19,967,000 ($17,439,000 net of tax) and unrealized losses $78,449,000 ($68,517,000 net of tax), respectively. For the same periods in 2011 the change in fair value of these investments represented unrealized losses of $528,000 ($457,000 net of tax) and unrealized gains of $60,946,000 ($52,761,000 net of tax), respectively.

8. DEBT

($ thousands)	September 30, 2012	December 31, 2011
Current:		
Current portion of long-term debt	$ 45,241	$ 46,808
	45,241	46,808
Long-term:		
Bank credit facility	$ 307,270	$ 446,182
Senior notes		
CDN$30 million (Matures May 15, 2019)	30,000	–
US$20 million (Matures May 15, 2022)	19,674	–
US$355 million (Matures May 15, 2024)	349,214	–
CDN$40 million (Matures September 18, 2015)	40,000	40,000
US$40 million (Matures September 18, 2015)	39,348	40,680
US$225 million (Matures September 18, 2021)	221,333	228,825
US$54 million (Matures October 1, 2015)(1)	31,872	32,951
US$175 million (Matures September 19, 2014)(2)	34,617	71,648
	1,073,328	860,286
Total debt	$ 1,118,569	$ 907,094

(1) The outstanding U.S. principal as at September 30, 2012 was US$43,200,000, a portion of which is classified as current.
(2) The outstanding U.S. principal as at September 30, 2012 was US$70,000,000, a portion of which is classified as current.

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

Issue Date	Original Principal ($ millions)	Remaining Principal ($ millions)	Coupon Rate	Interest Payment Dates	Repayment
May 15, 2012	CDN$ 30,000	CDN$ 30,000	4.34%	May 15 and Nov 15	Bullet payment on May 15, 2019
May 15, 2012	US$ 20,000	US$ 20,000	4.40%	May 15 and Nov 15	Bullet payment on May 15, 2022
May 15, 2012	US$ 355,000	US$ 355,000	4.40%	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020
June 18, 2009	CDN$ 40,000	CDN$ 40,000	6.37%	June 18 and Dec 18	Bullet payment on June 18, 2015
June 18, 2009	US$ 40,000	US$ 40,000	6.82%	June 18 and Dec 18	Bullet payment on June 18, 2015
June 18, 2009	US$ 225,000	US$ 225,000	7.97%	June 18 and Dec 18	5 equal annual installments beginning June 18, 2017
Oct 1, 2003	US$ 54,000	US$ 43,200	5.46%	April 1 and Oct 1	5 equal annual installments beginning Oct 1, 2011
June 19, 2002	US$ 175,000	US$ 70,000	6.62%	June 19 and Dec 19	5 equal annual installments beginning June 19, 2010

On October 31, 2012 Enerplus' $1,000,000,000 bank credit facility was extended to October 31, 2015. There were no changes to the pricing, bank syndicate or the size of the facility.

9. DECOMMISSIONING LIABILITY

Enerplus has estimated the net present value of its decommissioning liability to be $578,951,000 as at September 30, 2012 compared to $563,763,000 at December 31, 2011, based on a total undiscounted liability of $633,548,000 and $644,922,000 respectively. The decommissioning liability was calculated using a risk free rate of 2.32% at September 30, 2012 (December 31, 2011 – 2.49%).

($ thousands)	Nine months ended September 30, 2012	Year ended December 31, 2011
Decommissioning liability, beginning of year	$ 563,763	$ 392,709
Change in estimates	14,955	174,807
Property acquisition and development activity	4,742	4,828
Dispositions	(480)	(692)
Capitalized decommissioning costs	19,217	178,943
Decommissioning expenditures	(14,406)	(21,656)
Accretion	10,324	13,803
Foreign currency translation adjustment	53	(36)
Decommissioning liability, end of period	$ 578,951	$ 563,763

10. FINANCE EXPENSE

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2012	2011	2012	2011
Realized:				
Interest on bank debt and senior notes	$ 14,864	$ 10,726	$ 39,140	$ 35,316
Unrealized:				
Cross currency interest rate swap loss /(gain)	756	(3,881)	2,488	(2,786)
Interest rate swap loss /(gain)	(356)	133	(920)	(1,074)
Amortization of debt transaction costs	303	320	1,097	889
Accretion of decommissioning liability	3,356	3,450	10,324	10,244
Finance expense	$ 18,923	$ 10,748	$ 52,129	$ 42,589

11. FOREIGN EXCHANGE

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2012	2011	2012	2011
Realized:				
Foreign exchange loss/(gain)	$ 4,123	$ (3,872)	$ 10,031	$ 16,436
Unrealized:				
Translation of U.S. dollar debt loss/(gain)	(25,370)	31,690	(15,815)	18,567
Cross currency interest rate swap loss/(gain)	2,505	(5,098)	(14,807)	(18,464)
Foreign exchange swaps loss/(gain)	5,133	(16,543)	1,706	(13,242)
Foreign exchange loss/(gain)	$ (13,609)	$ 6,177	$ (18,885)	$ 3,297

12. INCOME TAXES

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2012	2011	2012	2011
Current tax expense/(recovery)				
Canada	$ 239	$ –	$ 116	$ 6
U.S.	(2,488)	32,333	2,183	76,323
Total current tax expense/(recovery)	$ (2,249)	$ 32,333	$ 2,299	$ 76,329
Deferred tax expense/(recovery)	(37,239)	15,540	(5,209)	60,280
Total income tax expense/(recovery)	$ (39,488)	$ 47,873	$ (2,910)	$ 136,609

13. SHAREHOLDERS' CAPITAL

(a) Share Capital

Authorized unlimited number of common shares	Nine months ended September 30, 2012		Year ended December 31, 2011	
Issued: (thousands)	**Shares**	**Amount**	**Shares**	**Amount**
Balance, beginning of year	181,159	$ 3,442,364	176,946	$ 5,639,380
Corporate Conversion:				
Reclassification of EELP units (non-cash)	–	–	1,703	44,387
Reclassification of Accumulated Deficit (non-cash)	–	–	–	(2,314,775)
Issued for cash:				
Public offerings	14,709	330,618	–	–
Dividend reinvestment plan	955	19,150	1,928	52,375
Stock Option Plan	68	1,180	582	11,626
Non-cash:				
Stock Dividend Plan	1,045	13,987	–	–
Stock Option Plan	–	1,119	–	9,371
Balance, end of period	197,936	$ 3,808,454	181,159	$ 3,442,364

(b) Dividends

For the three months ended September 30, 2012, Enerplus paid cash dividends of $44,850,000 (September 30, 2011 – $97,416,000) and issued stock dividends of $8,544,000. For the nine months ended September 30, 2012 Enerplus paid cash dividends of $234,001,000 (September 30, 2011 – $291,179,000) and issued stock dividends of $13,987,000.

(c) Equity Based Compensation

The following table summarizes Enerplus' equity based compensation expense:

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2012**	**2011**	**2012**	**2011**
Cash:				
Long term incentive plans expense/(recovery)	$ 5,224	$ 1,245	$ 5,355	$ 10,770
Non-Cash:				
Stock option plan expense	2,588	2,805	7,697	9,583
Equity total return swap loss /(gain)	(2,746)	–	(3,089)	–
Equity based compensation expense	$ 5,066	$ 4,050	$ 9,963	$ 20,353

(i) Stock Option Plan

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

Weighted average for the period	September 30, 2012	December 31, 2011
Dividend yield(1)	8.2%	7.14%
Volatility(1)	28.4%	35.0%
Risk-free interest rate	1.35%	2.34%
Forfeiture rate	10%	9.4%
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 in 2012 was $2.23 (September 30, 2011 – $4.40). At September 30, 2012, 3,159,000 options were exercisable at a weighted average reduced exercise price of $30.10 with a weighted average remaining contractual term of 3.35 years, giving an aggregate intrinsic value of nil (September 30, 2011 – $4,613,000).

For the nine months ended September 30, 2012, a total of 68,000 (September 30, 2011 – 559,000) options were exercised at a weighted average reduced exercise price of $17.35 (September 30, 2011 – $20.01). The weighted average share price throughout the period was $17.97.

For the three and nine months ended September 30, 2012, Enerplus expensed a total of $2,588,000 (September 30, 2011 – $2,805,000) and $7,697,000 (September 30, 2011 – $9,583,000) respectively related to its stock option plan. The remaining unamortized grant date fair value of outstanding options of $9,607,000 (September 30, 2011 – $9,583,000) will be recognized in net income over the remaining vesting period. Activity for the periods is as follows:

	Nine months ended September 30, 2012		Year ended December 31, 2011	
	Number of Options (000's)	Weighted Average Exercise Price[1]	Number of Options (000's)	Weighted Average Exercise Price[1]
Options outstanding				
Beginning of year	5,098	$ 29.41	5,457	$ 32.11
Granted	7,291	19.01	2,154	30.27
Exercised	(68)	17.35	(582)	19.97
Forfeited	(841)	25.32	(845)	33.22
Expired	–	–	(1,086)	47.05
End of period	11,480	$ 23.18	5,098	$ 29.41
Options exercisable at the end of period	3,159	$ 30.10	1,932	$ 33.86

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

The following table summarizes the Contributed Surplus balance as at:

($ thousands)	September 30, 2012	December 31, 2011
Cancelled shares	$ 3,795	$ 3,795
Stock option plan	29,693	23,115
Balance, end of period	$ 33,488	$ 26,910

(ii) Long-term Incentive Plans

The following table summarizes the Performance Share Units ("PSU"), Restricted Share Units ("RSU") and Director Share Units ("DSU") activity for the nine months ended September 30, 2012:

(thousands of units)	PSUs	RSUs	DSUs
Number of units, beginning of year	170	895	14
Granted	488	686	29
Settled	–	(485)	(9)
Forfeited	(51)	(111)	–
Number of units, end of period	607	985	34

At September 30, 2012 the long term incentive plans had a liability balance of $13,214,000 (December 31, 2011 – $21,254,000).

Enerplus has entered into an equity total return swap derivative ("equity swap") with respect to its cash settled long term incentive plans. Under the equity swap Enerplus effectively fixed the settlement cost on 800,000 units outstanding under the plans at price of approximately $12.64

per unit. At September 30, 2012 the equity swap was in a gain position of $3,089,000 and the change in fair value for the three and nine months ended September 30, 2012 was $2,746,000 and $3,089,000 respectively (refer to Note 14).

(d) Basic and Diluted Earnings per Share

Net income per share has been determined based on the following:

	Three months ended September 30,		Nine months ended September 30,	
(thousands of shares)	2012	2011	2012	2011
Weighted average shares	197,618	180,266	194,753	179,566
Dilutive impact of options	158	381	191	381
Diluted shares	197,776	180,647	194,944	179,947

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

Enerplus' non-derivative financial instruments include accounts receivable, accounts payable, marketable securities, dividends payable, bank indebtedness and long-term debt.

(i) Accounts Receivable, Accounts Payable, Dividends Payable, Bank Credit Facilities and Senior Notes

The carrying value of accounts receivable, accounts payable, dividends payable and bank credit facilities approximated their fair value at September 30, 2012 and December 31, 2011 due to their short term nature. At September 30, 2012 the combined fair values of Enerplus' senior notes was $907,232,000 and the carrying amount was $811,297,000 (December 31, 2011 – fair value of $540,426,000 and carrying value of $460,912,000). 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. At September 30, 2012 a current deferred financial asset of $54,878,000, a current deferred financial credit of $20,247,000, a non-current deferred financial asset of $7,196,000 and a non-current deferred financial credit of $17,061,000 are recorded on the Consolidated Balance Sheet. The following table summarizes the change in fair value for the three months ended September 30, 2012:

($ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swap	Foreign Exchange Swaps	Electricity Swaps	Equity Swap	Commodity Derivative Instruments Oil	Commodity Derivative Instruments Gas	Total
Deferred financial assets/(liabilities), beginning of period	$ (1,039)	$ (30,738)	$ 10,069	$ 1,086	$ 343	$101,031	$ –	$ 80,752
Change in fair value gain/(loss)	356(1)	(3,260)(2)	(5,133)(3)	(2,001)(4)	2,746	(47,332)(5)	(1,362)(5)	(55,986)
Deferred financial assets/(liabilities), end of period	**$ (683)**	**$ (33,998)**	**$ 4,936**	**$ (915)**	**$ 3,089**	**$ 53,699**	**$ (1,362)**	**$ 24,766**

(1) Recorded in finance expense.
(2) Recorded in foreign exchange expense (loss of $2,505) and finance expense (loss of $756).
(3) Recorded in foreign exchange expense.
(4) Recorded in operating expense.
(5) Recorded in commodity derivative instruments.
(6) Recorded in equity based compensation expense.

The following table summarizes the change in fair value for the nine months ended September 30, 2012:

($ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swap	Foreign Exchange Swaps	Electricity Swaps	Equity Swap	Commodity Derivative Instruments Oil	Commodity Derivative Instruments Gas	Total
Deferred financial assets/(liabilities), beginning of period	$ (1,603)	$ (46,317)	$ 6,642	$ 2,255	$ –	$ (19,611)	$ –	$ (58,634)
Change in fair value gain/(loss)	920[(1)]	12,319[(2)]	(1,706)[(3)]	(3,170)	3,089	73,310[(5)]	(1,362)[(5)]	83,400
Deferred financial assets/(liabilities), end of period	**$ (683)**	**$ (33,998)**	**$ 4,936**	**$ (915)**	**$ 3,089**	**$ 53,699**	**$ (1,362)**	**$ 24,766**

(1) Recorded in finance expense.
(2) Recorded in foreign exchange expense (gain of $14,807) and finance expense (loss of $2,488).
(3) Recorded in foreign exchange expense.
(4) Recorded in operating expense.
(5) Recorded in commodity derivative instruments.
(6) Recorded in equity based compensation expense.

The following table summarizes the ending balances as at September 30, 2012:

($ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swap	Foreign Exchange Swaps	Electricity Swaps	Equity Swap	Commodity Derivative Instruments Oil	Commodity Derivative Instruments Gas	Total
Current assets/(liabilities)	$ (683)	$ (16,937)	$ (350)	$ (915)	$ 1,179	$ 53,699	$ (1,362)	$ 34,631
Non-current assets/(liabilities)	–	(17,061)	5,286	–	1,910	–	–	(9,865)
Total	**$ (683)**	**$ (33,998)**	**$ 4,936**	**$ (915)**	**$ 3,089**	**$ 53,699**	**$ (1,362)**	**$ 24,766**

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

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2012	2011	2012	2011
Change in fair value gain/(loss)	$ (48,694)	$ 121,584	$ 71,948	$ 115,004
Net realized cash gain/(loss)	7,914	(4,481)	2,328	(22,211)
Commodity derivative instruments gain/(loss)	$ (40,780)	$ 117,103	$ 74,276	$ 92,793

(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 to a maximum of 80% of forecasted production volumes net of royalties.

Crude Oil Instruments:

At September 30, 2012 the fair value of Enerplus' crude oil derivative contracts represented an asset of $53,699,000 and the change in fair value of these contracts for the three and nine months ended September 30, 2012 represented an unrealized loss of $47,332,000 and an unrealized gain of $73,310,000 respectively.

The following table summarizes Enerplus' crude oil risk management positions at October 25, 2012:

Instrument Type	bbls/day	US$/bbl[1]
Oct 1, 2012 – Oct 31, 2012		
WTI Swap	17,500	95.83
WTI Purchased Put	1,000	103.00
WTI Purchased Call	1,000	103.00
WTI Sold Put	2,000	65.00
WTI Sold Call	1,000	133.00
Brent – WTI Spread	3,000	13.71
Nov 1, 2012 – Dec 31, 2012		
WTI Swap	17,500	95.83
WTI Purchased Put	1,000	103.00
WTI Purchased Call	1,000	103.00
WTI Sold Put	2,000	65.00
WTI Sold Call	1,000	133.00
Brent – WTI Spread	3,000	13.71
WCS Differential Swap	1,000	(12.25)
MSW Differential Swap	1,000	(1.75)
Jan 1, 2013 – Dec 31, 2013		
WTI Swap	17,000	100.84
WTI Purchased Call	3,500	104.09
WTI Sold Put	4,500	63.33
WTI Sold Call	3,500	130.00

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

Natural Gas Instruments:

At September 30, 2012 the fair value of Enerplus' natural gas derivative contracts represented a liability of $1,362,000 and the change in fair value of these contracts for the three and nine months ended September 30, 2012 represented an unrealized loss of $1,362,000.

The following table summarizes Enerplus' natural gas financial contracts at October 25, 2012:

Instrument Type	MMcf/day	CDN$/Mcf
Jan 1, 2013 – Dec 31, 2013		
AECO Swap	9.5	3.65
AECO Purchased Put	22.7	3.17

Enerplus also has the following physical gas contracts in place at October 25, 2012:

Instrument Type	MMcf/day	CDN$/Mcf
Oct 1, 2012 to Oct 31, 2012		
Fixed Price	84.0	2.14
Costless Collar	24.0	2.17-2.89
Nov 1, 2012 to Dec 31, 2012		
Costless Collar	14.2	2.12-2.91
AECO-NYMEX Basis	50.0	0.68
Jan 1, 2013 to Dec 31, 2013		
AECO-NYMEX Basis	53.0	0.67
Jan 1, 2014 to Dec 31, 2014		
AECO-NYMEX Basis	45.0	0.66

Electricity:

Enerplus is subject to electricity price fluctuations and it manages this risk by entering into forward fixed rate electricity derivative contracts on a portion of its electricity requirements. At September 30, 2012 the fair value of Enerplus' electricity contracts represented a liability of $915,000 and the change in fair value of these contracts for the three and nine months ended September 30, 2012 represented an unrealized loss of $2,001,000 and an unrealized loss of $3,170,000 respectively.

The following table summarizes Enerplus' electricity derivative contracts at October 25, 2012:

Instrument Type	MWh	CDN$/Mwh
Oct 1, 2012 – Dec 31, 2012		
AESO Power Swap(1)	13.0	54.04
Jan 1, 2013 – Dec 31, 2013		
AESO Power Swap(1)	9.0	66.08
Jan 1, 2014 – Dec 31, 2014		
AESO Power Swap(1)	3.0	57.00

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

15. SUBSEQUENT EVENT

On November 1, 2012 Enerplus entered into an agreement to sell its working interest in certain non-core assets for proceeds of approximately $220,000,000. The transaction is expected to close in December 2012.

BOARD OF DIRECTORS

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Calgary, Alberta

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

OFFICERS

ENERPLUS CORPORATION

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President & Chief Executive Officer

Ian C. Dundas
Executive Vice President & Chief Operating Officer

Ray J. Daniels
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P. Scott Walsh
Vice President, Information Systems

Kenneth W. Young
Vice President, Land

Michael R. Politeski
Controller, Finance

ENERPLUS RESOURCES (USA) CORPORATION

Edward McLaughlin
President

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Enerplus Partnership
Enerplus Resources (USA) Corporation

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ABBREVIATIONS

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

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 enerPLUS

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