VISION GROWTH INCOME

Third Quarter 2013 Financial Report

EAGLE ENERGY™
TRUST

EAGLE ENERGY™ TRUST

Management's Discussion and Analysis

November 7, 2013

This Management's Discussion and Analysis ("**MD&A**") of financial condition and results of operations for Eagle Energy Trust (the "**Trust**" or "**Eagle**"), dated November 7, 2013, should be read in conjunction with the Trust's unaudited interim condensed consolidated financial statements and accompanying notes for the three and nine months ended September 30, 2013 ("**Interim Financial Statements**") and the Trust's audited consolidated financial statements and accompanying notes and related MD&A for the year ended December 31, 2012 and the Trust's Annual Information Form dated March 22, 2013 ("**AIF**"), which are available online at www.sedar.com and on the Trust's website at www.eagleenergytrust.com.

The Condensed Consolidated Interim Financial Statements have been prepared in accordance with International Financial Reporting Standards ("**IFRS**"). Items included in the financial statements of each of the Trust's subsidiaries are measured using the currency of the primary economic environment in which the entity operates ("**the functional currency**"). The Condensed Consolidated Interim Financial Statements are presented in Canadian dollars, which is the functional and presentation currency of the Trust.

Figures within this MD&A are presented in Canadian dollars unless otherwise indicated.

This MD&A contains information that is forward looking. Investors should read the "Note about forward looking statements" section at the end of this MD&A.

Overview of the Trust

The Trust is an unincorporated open-ended limited purpose trust established under the laws of the Province of Alberta. The Trust's activities are restricted to owning property (other than real property or interests in real property), and it does not carry on business. The Trust's strategy is to invest in operating subsidiaries that will acquire onshore petroleum reserves and production with unexploited low risk development potential, located in certain regions of the U.S., and to pay out a portion of available cash to unitholders of the Trust on a monthly basis. The Trust provides investors with a publicly traded, petroleum focused, distribution producing investment, with favourable tax treatment relative to taxable Canadian corporations.

The Trust was formed on July 20, 2010, but did not commence active operations until November 24, 2010, the date of its initial public offering. During November and December 2010, the Trust raised $149.5 million, at an offering price of $10.00 per trust unit, through an initial public offering. Concurrent with closing its initial public offering the Trust acquired, indirectly through its wholly-owned subsidiary, an average 73% interest in the Salt Flat Field, a light oil property located near Luling in south central Texas, for $127.1 million. Consideration consisted of cash and 2,000,000 trust units valued at $20 million. In May 2012, the Trust closed a bought deal financing, including the proceeds from the exercise of the over-allotment option, of 8,680,000 trust units at a price of $11.00 per trust unit, for total proceeds of $95.5 million. Concurrent with closing this financing, Eagle acquired 92.5% of the seller's 99% interest in certain Permian Basin properties ("**Midland properties**"), located near Midland, Texas. After the closing, Eagle also acquired all of another party's 1% interest in the same properties. On April 22, 2013, the Trust acquired the remaining 7.5% of the seller's interest in the Midland properties.

Throughout this MD&A, Eagle Energy Trust and its subsidiaries are collectively referred to as "the Trust" for purposes of convenience. In addition, references to the results of operations refer to operations of the Trust's U.S. subsidiary.

Highlights for the three month period ended September 30, 2013

Eagle continues to demonstrate strong operational execution and consistent quarter over quarter results in 2013.

- Achieved top-decile third quarter field netbacks of $56.79 per barrel of oil equivalent ("**boe**"). The Trust's realized oil prices were at a premium to the benchmark West Texas Intermediate ("**WTI**") price. Field marketing contracts negotiated by Eagle contributed to top decile per boe field netbacks. With 100% of its production coming from Texas, Eagle has a substantial revenue advantage over peer Canadian producers.
- Posted third quarter average working interest production of 3,052 boe per day ("**boe/d**") (80% oil, 11% natural gas liquids, 9% natural gas), which is consistent with second quarter production levels, 8% higher than the comparable 2012 quarter and 22% higher than 2012 on a year to date basis. The Trust remains on track to meet its 2013 full year production guidance of 2,900 to 3,100 boe/d, which will result in greater than 15% year over year growth in average production.
- Lowered full year 2013 operating cost guidance to $12.00 per boe (previously $12.00 to $14.00 per boe) in recognition of ongoing success with operational efficiencies.
- Third quarter funds flow from operations of $11.6 million ($0.37 per unit) was 17% higher than the comparable 2012 quarter ($0.32 per unit). Excluding the $0.7 million one-time cash payment relating to accumulated vested restricted unit rights, second quarter funds flow was also surpassed.
- Third quarter distributions remained consistent at $0.26 per unit or $0.0875 per unit per month.
- Executed the final stages of the 2013 capital program by drilling, tying in and bringing on stream 3 (2.8 net) wells in Luling, and drilling 2 (2.0 net) wells and tying in and bringing on-stream 3 (3.0 net) wells in Midland. All wells were successful.

Acquisition

On November 4, 2013, the Trust announced its U.S. subsidiary had signed a purchase and sale agreement to acquire producing properties in Hardeman County, Texas for a purchase price of $US 26.3 million, subject to closing adjustments. The seller's current working interest production from the properties is approximately 300 boe per day, consisting of 97% light sweet crude (43° API) from 34 producing wells. The acquisition is expected to close on or about November 25, 2013, with an effective date of October 1, 2013. The acquisition is very attractive to Eagle as it is accretive in virtually all measures. Eagle estimates the average annual decline rate of the Hardeman County properties to be 12%. In addition, upon successful closing of this acquisition, Eagle's lenders have approved a further increase in Eagle's credit facility to $US 90.0 million consisting of a $US 80.0 million revolving facility and a new one year non-revolving credit facility of $US 10.0 million. The Trust intends to use an advance under this new credit facility to fund the acquisition.

Outlook

This outlook section excludes the Hardeman County acquisition.

This outlook section is intended to provide unitholders with information about Eagle's expectations as at the date hereof for production, operating costs, and capital expenditures for 2013. Readers are cautioned that the information may not be appropriate for any other purpose. This information constitutes forward-looking information. Readers should note the assumptions, risks and discussion under "Note about forward-looking statements".

The Trust continues to deliver on its 2013 production plan and sustain the progress made in lowering operating costs. Eagle's 2013 annualized production continues to be forecast at 2,900 to 3,100 boe/d and operating cost guidance has been updated to the low end of the range at $12.00/boe.

The Trust has updated its 2013 full year capital guidance to $US 29.2 million (previously $US 26.0 million) due to operational issues, primarily: (1) additional investment during drilling activities for extended coring, logging, and core and cutting analyses in order to mature play concepts in Luling and Midland (including Permian horizontal drilling potential); (2) additional funds to re-drill one Midland well due to issues with a drilling contractor that led to Eagle terminating the relationship and switching rigs and contractor; and (3) additional funds to repair well casing and associated recompletions costs for a well acquired by Eagle at Midland. Eagle is presently seeking reimbursement from the casing manufacturer.

Eagle's updated guidance with respect to its capital budget, production, operating costs and funds flow from operations, excluding the Hardeman County acquisition, is as follows:

	Updated 2013 Guidance	Previous 2013 Guidance	Notes
Capital Budget	$US 29.2 mm	$US 26.0 mm	(1)
Working Interest Production	2,900 to 3,100 boe/d	2,900 to 3,100 boe/d	
Operating Costs (inclusive of transportation)	$12.00 per boe	$12.00 to $14.00 per boe	(2)
Funds Flow from Operations	$45.0 mm	$45.0 mm	(3)

Notes:

(1) The capital budget amount does not include the cost of acquisitions.

(2) The Trust expects operating costs for the year to be at the low end of previous guidance.

(3) 2013 funds flow from operations of $45.0 million has been estimated using the following assumptions:

a. based on actual results through to September 30, 2013;

b. full year average working interest production of 3,000 boe/d, which is at the mid-range of guidance;

c. October - December benchmark pricing of $US 100.00 per barrel WTI oil, $US 2.90 per Mcf NYMEX gas and $US 44.00 per barrel NGLs (NGLs price is calculated as 44% of the WTI price);

d. October - December field marketing contracts currently in place for both Midland and Luling, as described in the "Revenue" section of this MD&A, and a WTI to LLS premium of $US 3.03 per barrel;

e. October - December average operating costs (inclusive of transportation) of $12.60 per boe; and

f. October - December foreign exchange rate at $1.00 CDN/US.

A table showing the sensitivity of Eagle's 2013 funds flow to changes in production and commodity prices is set out below under the heading "2013 Sensitivities".

Calculations and commentary regarding the sustainability of Eagle's distributions

The following table sets out Eagle's 2013 updated guidance with respect to its projected payout ratios, debt to trailing cashflow, and percentage to be drawn on its credit facility.

	Updated 2013 Guidance	Previous 2013 Guidance	Notes
Payout Ratios (as a percentage of funds flow)			
Basic Payout Ratio (i.e., assuming annualized distribution at $1.05/unit)	72%	71%	(1)
Plus: Capital Expenditures	67%	57%	(2)
Equals: Corporate Payout Ratio	139%	128%	(3)
Adjusted Payout Ratio (i.e., distribution - DRIP proceeds + capital expenditures)	93%	83%	(4)
Financial Strength			
Debt to trailing cashflow	1.03x	0.88x	(5)
% Drawn on existing credit facility at end of period	66%	66%	(6)

Notes:

(1) Eagle calculates its basic payout ratio as follows:

$$\frac{\text{Unitholder Distributions}}{\text{Funds Flow from Operations}} = \text{Basic Payout Ratio}$$

A table showing the sensitivity of Eagle's basic payout ratio to production and pricing is set out below under the heading "2013 Sensitivities".

(2) Capital expenditures generally exclude corporate and property acquisitions because these are evaluated separately on their own merits. The $US 8.6 million acquisition in Midland and the $US 26.3 million in Hardeman County have therefore been excluded from this percentage.

(3) Eagle calculates its corporate payout ratio as follows:

$$\frac{\text{Capital Expenditures + Unitholder Distributions}}{\text{Funds Flow from Operations}} = \text{Corporate Payout Ratio}$$

A table showing the sensitivity of Eagle's corporate payout ratio to production and pricing is set out below under the heading "2013 Sensitivities".

(4) Assumes 65% unitholder participation in Eagle's Premium Drip™ and distribution reinvestment programs is unchanged throughout 2013. As is the case with any manner of equity funding, Eagle weighs the benefits of this method of financing and will make adjustments as deemed prudent.

(5) Increased due to updated full year capital guidance.

(6) The borrowing base under the credit facility is $US 70.0 million.

2013 Sensitivities

The following tables show the sensitivity of Eagle's funds flow, corporate payout ratio and basic payout ratio to changes in commodity price and production.

Sensitivity of Funds Flow ($ millions) to Commodity Price and Production

		2013 (Oct – Dec) Average WTI		
		$US 90.00	$US 100.00	$US 110.00
2013 Average Working Interest Production (boe/d)	2,900	42.2	42.9	43.5
	3,000	44.2	45.0	45.4
	3,100	46.1	46.7	47.3

Sensitivity of Corporate Payout Ratio to Commodity Price and Production

		2013 (Oct – Dec) Average WTI		
		$US 90.00	$US 100.00	$US 110.00
2013 Average Working Interest Production (boe/d)	2,900	147%	145%	143%
	3,000	141%	139%	137%
	3,100	135%	133%	132%

Sensitivity of Basic Payout Ratio to Commodity Price and Production

		2013 (Oct – Dec) Average WTI		
		$US 90.00	$US 100.00	$US 110.00
2013 Average Working Interest Production (boe/d)	2,900	77%	75%	74%
	3,000	73%	72%	71%
	3,100	70%	69%	69%

Assumptions:

(1) Annual distributions are held at current levels of $1.05 per unit per year.

(2) No new equity issued other than under the distribution reinvestment program.

(3) Field operating costs (including transportation) from October to December 2013 of $12.60 per barrel.

Sensitivities

The Trust's results and ability to generate sufficient amounts of cash to fund ongoing operations are affected by external market factors such as fluctuations in the prices of crude oil and natural gas as well as movements in foreign-exchange rates and interest rates. Changes in production also affect funds flow. Sensitivities to these factors are summarized below.

	Quarterly impact on ➔	**Funds flow from operations ($000's)**	**Funds flow from operations / unit**
Gas price(2)	+ USD $0.10/mcf Henry HUB	8	0.00
Oil price (2)	+ USD $1.00/bbl WTI	204	0.01
Gas production	+1000 mcf/d	182	0.01
Oil production	+100 bbls/d	592	0.02
Currency (2)	+CDN strengthen by $0.01	(180)	(0.01)
Interest Rate	+1% prime	(112)	(0.00)

Notes:

(1) Per unit figures are based on 30,282,160 weighted average basic units outstanding for the nine months ended September 30, 2013.

(2) Price and currency sensitivities are calculated assuming an average yearly production rate equal to year to date average working interest sales volumes of 3,002 boe per day.

Results of operations

Production

Oil equivalent sales volumes (boe/d @ 6:1)	**Three Months Ended September 30, 2013**	Three Months Ended September 30, 2012	%	**Nine Months Ended September 30, 2013**	Nine Months Ended September 30, 2012	%
Oil (bbl/d)	2,447	2,477	(1)	2,490	2,289	9
Natural gas (Mcf/d)	1,559	927	68	1,336	467	186
Natural gas liquids (bbl/d)	345	194	78	289	99	192
	3,052	2,825	8	**3,002**	2,466	22

Working interest sales volumes for the third quarter of 2013 averaged 3,052 boe/d (80% oil, 11% natural gas liquids, 9% natural gas). The year over year increase of 8% is over and above production volumes required to overcome base decline and is a result of more efficient production operations, the Midland properties acquisition (2013 working interest top up), and well tie ins at Midland and Luling since September 30, 2012. For the nine months ended September 30, 2013, working interest sales volumes were 22% higher than the comparable 2012 period. As above, the increase is due to more effective base management, drilling activity and the Midland properties acquisition (2013 working interest top up).

Eagle has recently undertaken a comprehensive well by well review, which included looking at overall corporate declines. Eagle estimates its overall corporate decline at approximately 22% heading into the fourth quarter of 2013. This compares favorably to an overall corporate decline rate in 2012 exceeding 32%.

Revenue ($000's)		**Three Months Ended September 30, 2013**		Three Months Ended September 30, 2012	%		**Nine Months Ended September 30, 2013**		Nine Months Ended September 30, 2012	%
Oil	$	25,428	$	19,844	28	$	70,182	$	56,955	23
Natural gas		513		253	103		1,324		333	298
Natural gas liquids		1,157		645	79		2,766		969	185
Sales before royalties	**$**	**27,098**	$	20,742	31	**$**	**74,272**	$	58,257	27

Realized Prices										
Oil ($/bbl)	$	112.94	$	87.09	30	$	103.23	$	90.80	14
Natural gas ($/Mcf)		3.57		2.97	21		3.63		2.61	39
Natural gas liquids ($/bbl)		36.49		36.17	1		35.11		35.86	(2)
Sales before royalties ($/boe)		96.51		79.80	21		90.64		86.23	5
Royalties ($/boe)		(27.00)		(21.40)	26		(25.37)		(23.76)	7
Revenue ($/boe)	**$**	**69.51**	$	58.41	19	**$**	**65.27**	$	62.47	4

Benchmark Prices										
Oil – WTI ($US/bbl)	**$**	**105.82**	$	92.18	15	**$**	**98.15**	$	96.71	1
Natural gas – Henry HUB ($US/Mcf)	**$**	**3.56**	$	2.80	27	**$**	**3.34**	$	2.52	33

The Trust's quarterly revenue is 94% derived from oil, 4% from natural gas liquids and 2% from natural gas. Realized oil prices were at a premium to benchmark $US WTI, while natural gas liquid prices were approximately 34% of benchmark $US WTI.

There is a quality differential between the benchmark WTI price and the $US price realized by the Trust. Eagle enters into field marketing contracts to obtain the most favourable pricing. Management monitors pricing regularly and endeavours to maximize realized sales prices while minimizing counterparty risk. A key part of the Trust's strategy is to acquire US properties which are close to markets and, in so doing, realize premium sales prices compared to Canadian production.

In the Luling area, a field marketing agreement was in place from March 2013 through August 2013 which fixed the Trust's reference price to Louisiana Light Sweet ("**LLS**") instead of WTI. When other field pricing adjustments that were concurrently fixed are also considered, the result was Eagle realizing a premium to the WTI price of $US 4.67 per barrel (excluding transportation costs). In September 2013, Eagle executed a similar field marketing agreement for the period from September 2013 to February 2014 in which it fixed the other field pricing adjustments (which resulted in a $US 3.76 per barrel improvement to Eagle's realized price when compared to the expired agreement), but let the differential between LLS and WTI float. Eagle continues to monitor this spread and has the ability to fix this differential in the future.

Throughout 2013, the LLS to WTI premium has narrowed significantly. When compared to Canadian producers of medium gravity crude, who faced third quarter discounts to WTI averaging $US 17.50 (for Western Canadian select), Eagle pricing remains attractive.

In the Midland area, a marketing agreement was in place from March 2013 through August 2013 that limited the discount from the WTI price to $US 2.14 per barrel (excluding transportation costs). Eagle has executed a similar field marketing agreement for the period from September 2013 to February 2014 that results in a premium to the WTI price of $US 0.83 per barrel (excluding transportation costs).

The benchmark WTI price increased 15% from the prior years' comparative quarter, with Canadian dollar realized prices increasing by a higher amount due to the weaker Canadian dollar. The above prices do not include realized gains or losses from financial commodity contracts, which amounted to a realized loss of $0.9 million ($3.28/boe) for the three months ended September 30, 2013 and a realized loss of $0.7 million ($0.87/boe) for the nine months ended September 30, 2013. See *Realized and unrealized risk management gain/loss.*

The overall royalty rate of approximately 28% was consistent with prior periods.

Operating costs

	Three Months Ended September 30, 2013		Three Months Ended September 30, 2012		%	Nine Months Ended September 30, 2013		Nine Months Ended September 30, 2012		%
	$	**/boe**	$	/boe		**$**	**/boe**	$	/boe	
Operating expenses		10.30		11.43	(10)		9.07		12.80	(29)
Transportation expenses		2.42		2.35	3		2.32		2.09	11
	$	**12.73**	$	13.78	(8)	**$**	**11.39**	$	14.89	(24)

Field operating expenses fell by 8% per boe when compared to the third quarter of 2012. The increase in operating expenses in the third quarter 2013 compared to the second quarter of 2013 is due to non-recurring well workover costs in Midland. Ongoing success with operational efficiencies has resulted in Eagle lowering its full year 2013 operating cost guidance to $12.00 per boe (previously $12.00 - $14.00 per boe). The year over year reduction in per boe operating costs is the result of operating efficiencies.

Depreciation, depletion and amortization

	Three Months Ended September 30, 2013		Three Months Ended September 30, 2012		%	Nine Months Ended September 30, 2013		Nine Months Ended September 30, 2012		%
	$	**/boe**	$	/boe		**$**	**/boe**	$	/boe	
Depreciation, depletion and amortization		**27.83**		23.83	17		**27.18**		24.91	9

The depletion, depreciation, and amortization provision for the three and nine months ended September 30, 2013 was based on proved plus probable reserves, including the future development costs associated with those reserves, as found in the year end 2012 independently prepared reserves evaluation reports for Salt Flat and Midland. The increase in the provision at September 30, 2013 when compared to the same period for 2012 resulted from increased production volumes attributable to the Midland properties acquisition.

Field netback

	Three Months Ended September 30, 2013				Three Months Ended September 30, 2012				Nine Months Ended September 30, 2013				Nine Months Ended September 30, 2012			
($000's)	**$**		**$**	**/boe**	$		$	/boe	**$**		**$**	**/boe**	$		$	/boe
Sales before royalties		27,098		96.51		20,742		79.80		74,272		90.64		58,257		86.23
Royalties		(7,581)		(27.00)		(5,561)		(21.40)		(20,788)		(25.37)		(16,052)		(23.76)
Operating expenses		(2,892)		(10.30)		(2,970)		(11.42)		(7,432)		(9.07)		(8,646)		(12.80)
Transportation expenses		(680)		(2.42)		(611)		(2.35)		(1,899)		(2.32)		(1,414)		(2.09)
Field netback	**$**	**15,945**	**$**	**56.79**	$	11,600	$	44.63	**$**	**44,153**	**$**	**53.88**	$	32,145	$	47.58
Sales volumes (boe/d)				**3,052**				2,825				**3,002**				2,466

During the quarter, benchmark WTI averaged $US 105.82 per barrel and the Trust realized a field netback of $56.79 per barrel. For the nine months ended September 30, 2013, benchmark WTI averaged $US 98.15 per barrel and the Trust realized a field net back of $53.88 per barrel. The increase in field netbacks over the prior year period is primarily due to lower operating expenses and higher realized prices.

Field netback is a non-IFRS financial measure. See "Non-IFRS financial measures".

Realized and unrealized risk management gain/loss

As part of the Trust's ongoing strategy to mitigate the effects of fluctuating prices on a portion of its production, the following contracts have been put in place:

Oil Fixed Price	Volume	Contract Term	Price $US
NYMEX (i)	500 bbls/d	May 2013 to Dec 2013	$103.45
NYMEX (i)	400 bbls/d	Jan 2014 to Dec 2014	$98.00
NYMEX (ii)	800 bbls/d	Sep 2013 to Dec 2013	$95.00-$103.75
NYMEX (i)	300 bbls/d	Feb 2013 to Dec 2013	$93.25
NYMEX (i)	500 bbls/d	Jan 2014 to Dec 2014	$91.15
NYMEX (iii)	500 bbls/d	Jan 2014 to Dec 2014	$100.00
NYMEX (i)	400 bbls/d	Jan 2014 to Dec 2014	$91.15

(i) Represents a fixed price financial swap transaction with a set forward sale price (WTI reference prices).
(ii) Represents costless collar transactions created by buying puts and selling calls (WTI reference prices).
(iii) Represents a call swaption financial transaction with a set forward sale price (WTI reference prices).

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	%	**Nine Months Ended September 30, 2013**	Nine Months Ended September30, 2012	%
Realized loss (gain)	**$ 920**	$ (26)	-	**$ 711**	$ 23	(2,991)
Unrealized loss (gain)	3,795	3,853	2	3,772	(2,468)	-
Total net loss (gain)	**4,715**	3,827	(23)	**4,483**	(2,445)	-

For the three and nine months ended September 30, 2013, the net value of the commodity price contracts has decreased, compared to 2012. The net value of the contracts is dependent upon current and forward commodity pricing and, in the case of realized gains and losses, the price of the contract relative to the benchmark oil price at time of expiry. Although the Trust currently has no intention of unwinding the contracts that are in place, it is required to calculate and record, using a mark-to-market valuation, the fair value of the remaining term of the contracts at the end of each reporting period, hence the change in value of the unrealized portion of the commodity contracts. Since the second quarter of 2013, a stronger forward commodity pricing environment has caused a decrease in the future value of these contracts and a corresponding switch from an asset position at June 30, 2013 to a liability position on the balance sheet at September 30, 2013.

Finance expense

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	%	**Nine Months Ended September 30, 2013**	Nine Months Ended September 30, 2012	%
Finance expense	**$ 620**	$ 509	22	**$ 1,605**	$ 712	125
Per barrel	**2.21**	1.96	13	**1.96**	1.05	86

For the three and nine months ended September 30, 2013, finance expense increased due to greater average debt levels associated with acquisitions and increased capital investment. Higher 2013 debt levels are a result of: (1) the substantial completion of the 2013 capital program, and (2) the successful execution of the $US 8.6 million acquisition in Midland.

As of September 30, 2013, the effective interest rate on bank debt for the period was 3.8% compared to 4.5% for the comparable period in 2012. During 2013, the Trust utilized Euro dollar advances at a lower LIBOR rate than the base rate option on its borrowings.

Administrative expenses

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	%	**Nine Months Ended September 30, 2013**	Nine Months Ended September 30, 2012	%
Administrative expenses	**$ 2,027**	$ 1,289	57	**$ 5,472**	$ 5,337	3
Per barrel	**7.22**	4.96	46	**6.68**	7.90	(15)

Total administrative expenses for the third quarter ended September 30, 2013 were 57% above the third quarter in 2012 and 3% above the comparative nine month period in 2012. Over the past year, engineering, field and accounting staff were added to assist with full cycle development of the Luling and Midland areas, acceleration of the strategic focus on potential acquisitions and management of planned activities. Staff and related employment costs account for 48% of annual administrative expenses.

Administrative expenses for the third quarter of 2013 remained relatively flat when compared to the second quarter of 2013 but decreased on a per barrel basis from $7.36 per boe to $7.22 per boe. With additional staff in place, Eagle has now built its in-house capabilities to enable it to continue to execute on optimization and growth opportunities.

Unit-based compensation

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	%	**Nine Months Ended September 30, 2013**	Nine Months Ended September 30, 2012	%
Unit-based compensation expense	**$ 3,940**	$ 2,332	69	**$ 5,336**	$ 5,330	-

The dollar amount of unit-based compensation expense does not represent cash paid by the Trust.

The actual total value received by holders of the awards will depend on the accumulated distributions actually paid by the Trust combined with the actual year over year price appreciation of the trust units with respect to holders of the restricted unit rights and unit rights, and the actual price of the units relative to the exercise price of the options at the time the options are exercised (which would not result in a cash outlay for the Trust).

The Trust is, however, required to re-determine the fair value of the liability each quarter relating to: (1) the restricted unit rights, (2) the options and (3) the unit rights. Any changes in fair value are recorded as an expense.

From one reporting period to the next, changes in the closing price of the units, accumulated distributions and expected future unit price volatility will increase or decrease the fair values of the unit based awards as calculated under the Black-Scholes valuation model. These fair value changes cause corresponding swings in the amount recorded in the income statement. For the nine month comparative periods, the increase in the unit based payment liability and associated expense from September 30, 2012 to September 30, 2013 was due to additional awards vesting over time and additional awards being granted during that period.

During the quarter, $0.8 million was paid in cash for amounts related to restricted unit rights and unit rights, and $1.0 million was paid for the nine months ended September 30, 2013 (three and nine months ended September 30, 2012 - $1.0 million). The liability accrued from inception for these cash settled awards was reduced by such cash payments.

During the third quarter 2012, $1.0 million was paid in cash to the restricted unit rights holders, representing two years of accumulated vested amounts for two-thirds of the restricted unit rights then vested. During the third quarter 2013, $0.7 million was paid in cash to the restricted unit rights holders, representing three years of accumulated vested amounts on the remaining one-third of the restricted unit rights then vested. These were one-time cumulative payments. As all restricted unit rights have now vested, the restricted unit rights holders will be entitled to monthly payments that track to monthly unit distributions.

Tax horizon

The tax horizon, as determined from a full cycle corporate model incorporating cash flows from the year-end reserves evaluation report plus all applicable U.S. deductions, indicates that no material U.S. taxes are expected to be payable in respect of income attributable to the Luling and Midland properties for several years. Management expects to extend this period through continued capital investments and additional acquisitions in the U.S. as the Trust executes its business plan. No taxes are expected to be payable by the Trust in Canada because the Trust will distribute its full taxable income each year to unitholders and will not be a SIFT trust, as defined under the *Income Tax Act* (Canada), provided that the Trust complies at all times with the investment restrictions as set forth in the Trust Indenture.

Summary of quarterly results

	Q3/2013	Q2/2013	Q1/2013	Q4/2012	Q3/2012	Q2/2012	Q1/2012	Q4/2011
($000's except for boe/d and per unit amounts)								
Sales volumes – boe/d	3,052	3,022	2,928	2,986	2,825	2,400	2,169	2,023
Revenue, net of royalties	19,517	17,162	16,805	16,519	15,181	13,077	13,947	11,798
per boe	69.51	62.42	63.77	60.13	58.41	59.90	70.67	63.40
Funds flow from operations	11,615	11,977	11,884	9,905	9,039	7,233	9,118	7,199
per boe	41.37	43.56	45.10	36.06	34.78	33.13	46.20	38.69
per unit – basic	0.37	0.39	0.40	0.34	0.32	0.31	0.50	0.39
per unit – diluted	0.37	0.39	0.40	0.32	0.32	0.31	0.50	0.39
Income (loss)	(3,241)	3,919	4,080	(403)	(1,095)	8,567	(952)	(1,426)
per unit – basic & diluted	(0.10)	0.13	0.14	(0.02)	(0.04)	0.37	(0.05)	(0.08)
Cash distributions declared	8,204	8,026	7,828	7,653	7,512	6,628	5,024	4,936
per issued unit	0.2625	0.2625	0.2625	0.2625	0.2625	0.2625	0.2625	0.2625
Current assets	9,950	11,443	9,913	14,464	14,209	18,758	16,447	13,385
Current liabilities	20,942	19,874	11,982	17,512	23,723	28,158	20,319	16,557
Total assets	306,021	311,271	283,112	284,802	283,913	291,273	156,477	158,885
Total non-current liabilities	55,069	50,654	39,873	42,111	35,136	27,192	489	503
Unitholders' equity	230,010	240,743	231,257	225,179	225,055	235,923	135,669	141,826
Units outstanding for accounting purposes	31,469	30,707[1]	29,960[1]	29,269[1]	28,654[1]	27,895[1]	18,847[1]	18,544[1]
Units issued	31,469	30,813	30,066	29,375	28,783	28,283	19,234	18,931

Note:

(1) Units outstanding for accounting purposes exclude those units issued due to the performance conditions that had to be met to enable such units to be released from escrow.

Funds flow from operations is a non-IFRS financial measure. See "Non-IFRS financial measures".

Sales volumes in the third quarter of 2013 remained relatively consistent with second quarter 2013 levels. Refer to the section of this MD&A titled "Activity Summary" for additional discussion.

Funds flow from operations decreased 3% in the third quarter of 2013 when compared to the prior quarter. Although the Trust realized higher WTI prices in the third quarter, resulting in higher revenue when compared to the second quarter of 2013, the increase in revenue was offset by: (1) increased operating expenses in the third quarter 2013 due to non-recurring workover costs on the Midland properties, (2) a one-time payment on vested restricted unit rights and (3) cash payments on risk management contracts. Generally, in times of steady or increasing prices, funds flow from operations will grow as sales volumes increase and, on a per-boe basis, will decline when volumes decline. This is because certain expenses tend to be more fixed in nature, such as general and administrative expenses, and do not decrease as sales volumes decrease.

Income (loss) on a quarterly basis often does not move directionally or by the same amount as movements in funds flow from operations. This is primarily due to items of a non-cash nature that factor into the calculation of income (loss), and items that are required to be fair valued at each quarter end. By way of example, third quarter 2013 funds flow from operations decreased 3% from the second quarter, while third quarter 2013 income decreased by 183%. This occurred for two reasons. First, a stronger commodity price environment during the third quarter of 2013 reduced the fair market valuation of Eagle's forward commodity contracts. Second, a higher unit price caused an increase in the expense recorded in the income statement due to the fair market valuation of future unit-based compensation payments.

Total non-current liabilities increased in the third quarter of 2013 compared to the second quarter of 2013 as a result of the substantial completion of the 2013 capital program.

Liquidity and capital resources

Generally, three sources of funding are available to the Trust: (1) internally generated funds flow from operations; (2) debt financing, when appropriate; and (3) the issuance of additional units, if available on favourable terms, including proceeds from the Trust's distribution re-investment programs.

Management aims to maintain a bank debt to cash flow ratio below 1.5 times.

The Trust believes that its expected funds flow from operations and undrawn credit facility will be sufficient to fund its current and expected financial obligations. Refer to the "Outlook" section for a discussion of the Trust's future plans. Other than the items noted in the "Commitments" section of this MD&A, capital spending and distributions are discretionary.

Funds flow from operations

The following table summarizes funds flow from operations on a per boe basis:

	Three Months Ended September 30, 2013		Three Months Ended September 30, 2012		**Nine Months Ended September 30, 2013**		Nine Months Ended September 30, 2012	
($000's)	**$**	**$ /boe**	$	$ /boe	**$**	**$ /boe**	$	$ /boe
Field netback	15,945	56.79	11,600	44.63	44,153	53.88	32,145	47.58
Cash settled award payments	(798)	(2.84)	(959)	(3.69)	(1,023)	(1.25)	(959)	(1.43)
Administrative expenses	(2,027)	(7.22)	(1,289)	(4.97)	(5,472)	(6.68)	(5,338)	(7.90)
Realized risk management (loss) gain	(920)	(3.28)	26	0.10	(711)	(0.87)	(23)	(0.03)
Finance expense	(540)	(1.92)	(407)	(1.56)	(1,383)	(1.69)	(652)	(0.96)
Realized foreign exchange loss (gain) (1)	(45)	(0.16)	68	0.27	(87)	(0.10)	217	0.32
Funds flow from operations	**$ 11,615**	**$ 41.37**	$ 9,039	$ 34.78	**$ 35,477**	**$ 43.29**	$ 25,390	$ 37.58

Note:

(1) This represents settled foreign currency transactions related to operating activities.

Funds flow from operations is a non-IFRS financial measure. See "Non-IFRS financial measures".

Credit facility

As of September 30, 2013, the Trust had approximately $US 9.8 million of unused credit on its $US 61.0 million syndicated credit facility, which is held indirectly through its U.S. subsidiary with two Canadian chartered banks. At December 31, 2012, the Trust had approximately $US 8.0 million of unused credit outstanding on a $US 48.5 million credit facility.

As a result of a semi-annual review, Eagle's lenders increased the borrowing base under the credit facility from $US 61.0 million to $US 70.0 million effective October 17, 2013. Additionally, the credit agreement was amended to extend the term from December 21, 2014 to May 29, 2015. All other terms and conditions remain unchanged.

Working capital

At September 30, 2013, the Trust had a working capital deficiency of $11.0 million, which becomes a $0.7 million surplus when the non-cash current portion of unit-based payments and current risk management contracts are excluded. As at September 30, 2013, $52.8 million (December 31, 2012 - $40.2 million) was drawn on its expanded $US 70.0 million bank credit facility described above.

Unitholders' equity

Other than the units released from escrow on September 14, 2013, all Trust capital issuances were issued pursuant to the distribution reinvestment plans as detailed below.

As a result of its Premium Distribution™ and Distribution Reinvestment Plan (collectively referred to as the "**Plan**"), the Trust received proceeds resulting from the issuance of units from treasury to those unitholders who have opted to participate in the Plan. For the three months ended September 30, 2013, 655,983 units (three months ended September 30, 2012 – 500,604 units) were issued for total proceeds of $5.0 million (three months ended September 30, 2012 - $4.6 million) at an average unit price of $7.68 (three months ended September 30, 2012 - $9.30 per unit). For the nine months ended September 30, 2013, 2,094,313 units (September 30, 2012 - 1,172,355 units) were issued for total proceeds of $15.0 million (September 30, 2012 - $11.5 million) at an average unit price of $7.15 (September 30, 2012 - $9.92 per unit).

Management may also seek to issue additional units in the future to provide sufficient capital to fund growth, including acquisition opportunities.

Distributions and outstanding unit data

The Trust pays monthly distributions to unitholders at the discretion of the Board of Directors. Cash distributions paid in the third quarter (for the June, July, August 2013 record dates) were approximately $8.2 million.

At September 30, 2013, the Trust had issued 31,468,873 units.

As at the date of this MD&A, 31,678,384 units are issued and 2,681,750 options are outstanding.

Capital expenditures

Capital expenditures during the three and nine months ended September 30, 2013 and September 30, 2012 were as follows:

	Three Months Ended September30, 2013	Three Months Ended September 30, 2012	**Nine Months Ended September 30, 2013**	Nine Months Ended September 30, 2012
(000's)	**$**	$	**$**	$
Exploration and evaluation[1]	7	99	63	183
Acquisition of Midland properties - 92.5% interest	-	-	-	115,680
Acquisition of Midland properties - 7.5% interest	-	-	8,830	-
Intangible drilling and completions	8,836	12,634	25,180	20,403
Well equipment and facilities	2,356	3,252	3,468	11,819
Office furniture and fixtures	(257)	-	80	-
Other	(2)	45	117	145
	$ 10,940	$ 16,030	**$ 37,738**	$ 148,230

Notes:

(1) Exploration and evaluation expenditures relate to amounts spent on land to which no proven reserves are yet assigned.

During the third quarter of 2013, the Trust incurred $8.8 million on drilling and completions. Of this total, $7.2 million was for drilling five wells and completing and fracturing six wells. Another $1.6 million was for recompleting existing wells to enhance production.

The Trust has updated its 2013 full year capital guidance to $US 29.2 million (previously $US 26.0 million) due to operational issues, primarily: (1) additional investment during drilling activities for extended coring, logging, and core and cutting analyses in order to mature play concepts in Luling and Midland (including Permian horizontal drilling potential); (2) additional funds to re-drill one Midland well due to issues with a drilling contractor that led to Eagle terminating the relationship and switching rigs and contractor and; (3) additional funds to repair well casing and associated recompletion costs for a well acquired by Eagle at Midland. Eagle is presently seeking reimbursement from the casing manufacturer.

On April 22, 2013, the Trust announced that it had acquired all of the remaining interest in its Midland properties for cash consideration of $8.8 million which includes closing adjustments of approximately $0.1 million. The Trust now owns a 100% working interest in its Midland area properties.

Consideration was comprised of cash. The acquisition has been accounted for as a business combination with the fair value of the net assets (preliminary purchase price allocation) as follows:

Identifiable assets acquired and liabilities assumed ($CAD):		
Oil and gas properties	$	8,914
Decommissioning liabilities		(84)
	$	**8,830**

Activity Summary

Wells Drilled	**Three Months Ended September 30, 2013**		Three Months Ended September 30, 2012		**Nine Months Ended September 30, 2013**		Nine Months Ended September 30, 2012	
	Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Luling	3	2.8	6	4.8	6	5.2	15	12.0
Midland	2	2.0	1	0.9	6	6.0	4	3.6
Total	**5**	**4.8**	7	5.7	**12**	**11.2**	19	15.6

Wells Brought on-stream	**Three Months Ended September 30, 2013**		Three Months Ended September 30, 2012		**Nine Months Ended September 30, 2013**		Nine Months Ended September 30, 2012	
	Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Luling	3	2.8	8	6.4	6	5.2	14	11.2
Midland	3	3.0	2	1.9	6	5.9	4	3.7
Total	**6**	**5.8**	10	8.3	**12**	**11.1**	18	14.9

Of the three oil wells that were brought on-stream in Luling, two commenced intermittent production in late September. The regional power company is now clearing their backlog of weather related calls and Eagle is getting these well sites electrified. This will allow the pumps to operate more reliably and at a lower cost.

At Midland, once the wells are fractured, they often flow up the casing and cleanup for up to 30 days before a pump is installed and peak well production is achieved. Two of the three Midland oil wells had pumps installed in late September and, even though the wells are performing to expectations, production contributions from the wells were negligible for the quarter.

Commitments

The Trust has committed to future payments as follows:

(000's)		Total		Less than 1 year		1 – 3 years		After 3 years
Operating leases [(1)(2)(3)(4)]		3,194		676		1,570		948
Software database[(5)]		299		123		176		-
Total contractual obligations	**$**	**3,493**	**$**	**799**	**$**	**1,746**	**$**	**948**

Notes:

(1) Calgary, Alberta office lease: On January 1, 2013, the Trust entered into a head-lease agreement for new office space which has an approximate 61 month term from January 8, 2013 to February 7, 2018. Future minimum lease payments during the term of the lease approximate $2.1 million and include an available leasehold improvements allowance up to $0.3 million, with 52 months and approximately $1.8 million remaining at September 30, 2013.

(2) Houston, Texas office lease: The lease agreement was entered into on April 1, 2011, and had an approximate 30 month term from April 7, 2011 through September 30, 2013. On November 21, 2012, the lease agreement was extended for an additional 63 month period from October 1, 2013 to December 31, 2017 and the premise space was expanded to incorporate additional square footage. Future minimum lease payments during the term of the lease include an available leasehold improvements allowance of $US 111,293 and approximate $US 1.5 million with 51 months and approximately $US 1.1 million remaining at September 30, 2013. In $CA the remaining future minimum lease payments approximate $1.2 million translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.03.

(3) Luling, Texas office lease: The lease agreement was entered into on August 15, 2011, and originally had an approximate 12 month term from August 15, 2011 through August 31, 2012. On April 24, 2012, the lease agreement was extended for an additional 36 month period from September 1, 2012 to August 31, 2015 at a monthly rate of $US 1,650. Future minimum payments during the term of the sublease and the extension approximate $US 80,000, 23 months and approximately with $US 38,000 remaining at September 30, 2013. In $CA, the remaining future minimum lease payments approximate $39,000 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.03.

(4) Midland, Texas office lease: The lease agreement was entered into on July 31, 2012 and has an approximate 48 month term from October 15, 2012 through October 14, 2016. Future minimum lease payments during the term of the lease approximate $US 203,000 with 36 months and approximately $US 152,000 remaining at September 30, 2013. In $CA the remaining future minimum lease payments approximate $157,000 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.03.

(5) Software database: A three year subscription agreement for technical software was entered into effective June 18, 2013. The total subscription commitment was estimated to be approximately $US 0.4 million with approximately $US 0.3 million remaining at September 30, 2013. In $CA, the net future commitment approximates $0.3 million translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 1.03.

Non-IFRS financial measures

Statements throughout this MD&A make reference to the terms "field netback" and "funds flow from operations" which are non-IFRS financial measures that do not have any standardized meaning prescribed by IFRS and may not be comparable to similar measures presented by other issuers. Management believes that "field netback" and "funds flow from operations" provide useful information to investors and management since such measures reflect the quality of production, the level of profitability, the ability to drive growth through the funding of future capital expenditures and the sustainability of distributions to unitholders. Funds flow from operations is calculated before changes in non-cash working capital and abandonment expenditures. Field netback is calculated by subtracting royalties and operating costs from revenues. Other financial data has been prepared in accordance with IFRS. The following table reconciles the non-IFRS financial measures "funds flow from operations" and "field netback" to "earnings (loss)", the most directly comparable measure in the Trust's condensed consolidated interim financial statements:

($000's)	**Three Months Ended September 30, 2013**	Three Months Ended September 30, 2012	**Nine Months Ended September 30, 2013**	Nine Months Ended September 30, 2012
Earnings (loss)	**$ (3,241)**	$ (1,095)	**$ 4,758**	$ 6,521
Add back (deduct) items not involving cash:				
Unit-based compensation - non-cash portion	3,141	1,373	4,313	4,371
Unrealized risk management (gain) loss	3,795	3,853	3,772	(2,468)
Depreciation, depletion and amortization	7,839	6,221	22,412	16,906
Deferred income tax	-	(1,415)	-	-
Finance expense	81	102	222	60
Funds flow from operations	**$ 11,615**	$ 9,039	**$ 35,477**	$ 25,390
Add back (deduct) items not directly related to field operations:				
Realized foreign exchange loss (gain)	45	(68)	87	(217)
Finance expense (cash portion)	540	407	1,383	652
Risk management (gain) loss-realized	920	(26)	711	23
Administrative expenses	2,027	1,289	5,472	5,338
Cash settled award payments	798	959	1,023	959
Field netback	**$ 15,945**	$ 11,600	**$ 44,153**	$ 32,145

No change in internal controls over financial reporting during the period July 1, 2013 to September 30, 2013

During the period beginning on July 1, 2013 and ended on September 30, 2013, there was no change in the Trust's internal controls over financial reporting that has materially affected, or is reasonably likely to materially affect, the Trust's internal controls over financial reporting. It should be noted, that the Trust's control system, no matter how well designed, can provide only reasonable, but not absolute assurance of detecting, preventing and deterring errors or fraud.

Critical accounting estimates

There have been no changes to the Trust's critical accounting estimates and judgments in the third quarter of 2013. Further information about the Trust's critical accounting estimates and judgments can be found in the notes to the Consolidated Financial Statements and MD&A for the year ended December 31, 2012.

Accounting standards and interpretations adopted

The Trust has adopted the following new and revised standards, along with any consequential amendments, effective January 1 2013. These changes were made in accordance with the applicable transitional provisions.

- IAS 1, Presentation of Financial Statements. The Trust has adopted the amendments to IAS 1 effective January 1, 2013. These amendments required the Trust to group other comprehensive income items by those that will be reclassified subsequently to profit or loss and those that will not be reclassified. The Trust has reclassified comprehensive income items of the comparative period. These changes did not result in any adjustments to other comprehensive income or comprehensive income.
- IFRS 10, Consolidated Financial Statements, replaces the guidance on control and consolidation in IAS 27, Consolidated and Separate Financial Statements, and SIC-12, Consolidation – Special Purpose Entities. The Trust assessed its consolidation conclusions on January 1, 2013 and determined that the adoption of IFRS 10 did not result in any change in the consolidation status of any of its subsidiaries.
- IFRS 11, Joint Arrangements, supersedes IAS 31, Interests in Joint Ventures, and requires joint arrangements to be classified either as joint operations or joint ventures depending on the contractual rights and obligations of each investor that jointly controls the arrangements. The Trust has classified its joint arrangements and concluded that the adoption of IFRS 11 did not result in any changes in the accounting for its joint arrangements.
- IFRS 13, Fair value measurement, provides a single framework for measuring fair value. The measurement of the fair value of an asset or liability is based on assumptions that market participants would use when pricing the asset or liability under current market conditions, including assumptions about risk. The Trust adopted IFRS 13 on January 1, 2013 on a prospective basis. The adoption of IFRS 13 did not require any adjustments to the valuation techniques used by the Trust to measure fair value and did not result in any measurement adjustments.
- IAS 19, Employee Benefits (amended in 2011), amends certain accounting requirements for defined benefits plans and termination benefits. These changes do not impact the Trust and it did not result in any adjustments to the Financial Statements.

The Trust will continue to monitor the adoption efforts of industry participants and the efforts of the CICA and industry groups. Additional adjustments to the Trust's accounting policies may be required upon completion of a separate IASB framework for extractive industries.

Note about forward-looking statements

Certain of the statements made and information contained in this MD&A are forward-looking statements and forward looking information (collectively referred to as "forward-looking statements") within the meaning of Canadian securities laws. All statements other than statements of historic fact are forward-looking statements. The Trust cautions investors that important factors could cause the Trust's actual results to differ materially from those projected, or set out, in any forward-looking statements included in this MD&A.

In particular, and without limitation, this MD&A contains forward looking statements pertaining to the following:

- the Trust's estimates regarding its 2013 capital budget and specific uses;
- the Trust's expectations regarding its average 2013 working interest production and 2013 operating costs;
- the Trust's expectations regarding its 2013 funds flow from operations and sensitivities of funds flow from operations to production rates and commodity prices;
- the Trust's expectations regarding its 2013 basic and corporate payout ratios and 2013 debt to trailing cashflow;
- the Trust's expectations regarding its bank debt to cash flow ratio;
- the Trust's expectations regarding the percentage to be drawn on its credit facility and specific uses including funding the Hardeman County property acquisition;
- the sensitivities of 2013 payout ratios to changes in production rates and commodity prices;
- the Trust's expectations regarding its overall decline rate;
- the Trust's expectations regarding its tax horizon;
- the anticipated completion of the Hardeman County property acquisition; and
- the Trust's expectation that its expected funds flow from operations and undrawn credit facility will be sufficient to fund its current and expected financial obligations.

With respect to forward-looking statements contained in this MD&A, assumptions have been made regarding, among other things:

- future oil, natural gas liquid and natural gas prices;
- future currency exchange and interest rates;
- future recoverability of reserves;
- future distribution levels;
- future capital expenditures and the ability of the Trust to obtain financing on acceptable terms for its capital projects and future acquisitions;
- the Trust's 2013 capital budget, which is subject to change in light of ongoing results, prevailing economic circumstances, commodity prices and industry conditions and regulations;
- not including capital required to pursue future acquisitions in the forecasted capital expenditures;
- estimates of anticipated production, which is based on the proposed drilling program with a success rate that, in turn, is based upon historical drilling success and an evaluation of the particular wells to be drilled;
- projected operating costs, which are based on historical information and anticipated increases in the cost of equipment and services;
- the level of unitholder participation in Eagle's Premium Drip ™ and distribution reinvestment programs; and
- the regulatory framework governing taxes in the U.S. and Canada and the Trust's status as a "mutual fund trust" and not a "SIFT trust".

The Trust's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and those in the Trust's Annual Information Form for the year ended December 31, 2012 (AIF) available on SEDAR at www.sedar.com:

- volatility of oil, natural gas liquid, and natural gas prices;
- commodity supply and demand;
- fluctuations in currency and interest rates;
- inherent risks and changes in costs associated in the development of petroleum properties;
- ultimate recoverability of reserves;
- timing, results and costs of drilling and production activities;
- unexpected operational delays and challenges;
- availability of financing and capital; and
- new regulations and legislation that apply to the Trust and the operations of its subsidiaries.

Additional risks and uncertainties affecting the Trust are contained in the AIF under the heading "Risk Factors".

As a result of these risks, actual performance and financial results in 2013 may differ materially from any projections of future performance or results expressed or implied by these forward-looking statements. The Trust's production rates, operating costs, drilling program, 2013 capital budget, funds flow from operations payout ratios, tax horizon Eagle's Premium Drip ™ and distribution reinvestment programs and distributions, among other things, are subject to change in light of ongoing results, prevailing economic circumstances, obtaining regulatory approvals, actual commodity prices, and industry conditions and regulations. New factors emerge from time to time, and it is not possible for management to predict all of these factors or to assess, in advance, the impact of each such factor on the Trust's business, or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward looking statement.

Undue reliance should not be placed on forward-looking statements, which are inherently uncertain, are based on estimates and assumptions, and are subject to known and unknown risks and uncertainties (both general and specific) that contribute to the possibility that the future events or circumstances contemplated by the forward looking statements will not occur. Although management believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date the forward-looking statements were made, there can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based will in fact be realized. Actual results will differ, and the difference may be material and adverse to the Trust and its unitholders. The Trust does not undertake any obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise.

Note regarding barrel of oil equivalency

This MD&A contains disclosure expressed as "boe" or "boe/d". All oil and natural gas equivalency volumes have been derived using the conversion ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of oil. Equivalency measures may be misleading, particularly if used in isolation. A conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. In addition, given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of six to one, utilizing a boe conversion ratio of 6 Mcf: 1 bbl would be misleading as an indication of value.

Eagle Energy Trust

Interim Condensed Consolidated Financial Statements
(in Canadian dollars) (unaudited)

For the three and nine months ended September 30, 2013 and September 30, 2012

Eagle Energy Trust

Condensed Consolidated Balance Sheets

(Thousands of Canadian dollars) (unaudited)

	Note		**September 30, 2013**		December 31, 2012
ASSETS					
Current assets					
Cash		$	2,485	$	4,007
Trade and other receivables			6,890		7,612
Prepaid expenses			575		531
Risk management asset	3		-		2,314
			9,950		**14,464**
Non-current assets					
Risk management asset	3		39		-
Exploration and evaluation			492		422
Oil and gas properties	10		294,803		269,233
Property, plant and equipment	11		347		282
Other intangible assets			390		401
			296,071		**270,338**
Total Assets		**$**	**306,021**	**$**	**284,802**
LIABILITIES					
Current liabilities					
Trade and other payables		$	6,537	$	8,313
Distributions payable	12		2,754		2,570
Unit-based payments	6		10,083		6,629
Risk management liability	3		1,568		-
			20,942		**17,512**
Non-current liabilities					
Risk management liability	3		-		123
Long-term debt	13		52,751		40,244
Decommissioning liability	14		2,318		1,744
			55,069		**42,111**
Total Liabilities		**$**	**76,011**	**$**	**59,623**
UNITHOLDERS' EQUITY					
Trust capital	15	$	292,297	$	276,526
Currency reserves			3,343		(5,017)
Accumulated earnings			6,448		1,690
Accumulated cash distributions			(72,078)		(48,020)
Total Unitholders' Equity		**$**	**230,010**	**$**	**225,179**
Total Liabilities and Unitholders' Equity		**$**	**306,021**	**$**	**284,802**

The notes are an integral part of these condensed financial statements.

See Note 18 "Commitments" and Note 19 "Subsequent events".

Eagle Energy Trust

Condensed Consolidated Statements of Earnings (Loss) and Comprehensive Income (Loss)

(Thousands of Canadian dollars, except per unit amounts) (unaudited)

	Note	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Revenue		$ 27,098	$ 20,742	$ 74,272	$ 58,257
Royalties		(7,581)	(5,561)	(20,788)	(16,052)
		19,517	**15,181**	**53,484**	**42,205**
Operating expenses		2,892	2,970	7,432	8,646
Transportation expenses		680	611	1,899	1,414
Administrative expenses		2,027	1,289	5,472	5,337
Depreciation, depletion and amortization		7,839	6,221	22,412	16,907
Operating profit		**6,079**	**4,090**	**16,269**	**9,901**
Unit based compensation expense	6	3,940	2,332	5,336	5,330
Finance expense	7	620	509	1,605	712
Risk management loss (gain)	3	4,715	3,827	4,483	(2,445)
Foreign exchange loss (gain), net		45	(68)	87	(217)
Earnings (Loss) before taxes		**(3,241)**	**(2,510)**	4,758	**6,521**
Income tax recovery	8	-	1,415	-	-
Earnings (Loss)		**$ (3,241)**	**$ (1,095)**	**$ 4,758**	**$ 6,521**
Other comprehensive income					
Items that may be reclassified subsequently to net income					
Foreign currency translation gain (loss)		(5,138)	(9,313)	8,360	(7,542)
Comprehensive income (loss)		**$ (8,379)**	**$ (10,408)**	**$ 13,118**	**$** (1,021)
Earnings (Loss) per unit					
Basic and diluted	9	**$ (0.10)**	**$ (0.04)**	**$ 0.16**	**$ 0.28**

The notes are an integral part of these condensed financial statements.

Eagle Energy Trust

Condensed Consolidated Statements of Changes in Unitholders' Equity

For the nine months ended September 30, 2013 and year ended December 31, 2012
(Thousands of Canadian dollars) (unaudited)

	Note	Number of trust units	Trust capital	Currency reserve	Accumulated earnings/ (loss)	Accumulated cash distributions	Deficit	Total Unitholders' equity
Balance at December 31, 2011		**18,544**	**168,175**	**(718)**	**(4,427)**	**(21,204)**	**(25,631)**	**$ 141,826**
Earnings		-	-	-	6,521	-	6,521	6,521
Foreign currency translation loss		-	-	(7,542)	-	-	-	(7,542)
Total comprehensive income		-	-	(7,542)	6,521	-	6,521	(1,021)
Issuance of trust capital		10,110	109,524	-	-	-	-	109,524
Trust unit issuance costs		-	(6,110)	-	-	-	-	(6,110)
Unitholder distributions		-	-	-	-	(19,163)	(19,163)	(19,163)
		10,110	103,414	-	-	(19,163)	(19,163)	84,250
Balance at September 30, 2012		**28,654**	**271,589**	**(8,260)**	**2,093**	**(40,367)**	**(38,274)**	**$ 225,055**
Balance at December 31, 2012		**29,269**	**276,526**	**(5,017)**	**1,690**	**(48,020)**	**(46,330)**	**$ 225,179**
Earnings		-	-	-	4,758	-	4,758	4,758
Foreign currency translation gain		-	-	8,360	-	-	-	8,360
Total comprehensive income		-	-	8,360	4,758	-	4,758	13,118
Issuance of trust capital	15	2,200	15,837	-	-	-	-	15,837
Trust unit issuance costs	15	-	(66)	-	-	-	-	(66)
Unitholder distributions	12	-	-	-	-	(24,058)	(24,058)	(24,058)
		2,200	15,771	-	-	(24,058)	(24,058)	(8,287)
Balance at September 30, 2013		**31,469**	**292,297**	**3,343**	**6,448**	**(72,078)**	**(65,630)**	**$ 230,010**

The notes are an integral part of these condensed financial statements.

Eagle Energy Trust

Condensed Consolidated Cash Flow Statements

For the three and nine months ended September 30, 2013 and September 30, 2012
(Thousands of Canadian dollars) (unaudited)

	Note	**Three Months Ended September 30, 2013**	Three Months Ended September 30, 2012	**Nine Months Ended September 30, 2013**	Nine Months Ended September 30, 2012
Cash flows from operating activities					
Net cash generated by operating activities	16	**$ 8,810**	**$ 4,218**	**$ 34,383**	**$ 27,514**
Cash flows from investing activities					
Additions to exploration and evaluation		(7)	(99)	(63)	(183)
Additions to oil and gas properties		(11,192)	(15,664)	(28,648)	(32,000)
Additions to property, plant and equipment		259	(45)	(197)	(145)
Acquisition of oil and gas assets	4	-	(222)	(8,830)	(115,902)
Net cash used in investing activities		**$ (10,940)**	**$ (16,030)**	**$ (37,738)**	**$ (148,230)**
Cash flows from financing activities					
Long-term debt		5,299	10,404	10,905	34,343
Proceeds from issuance of units		5,894	4,654	15,837	106,956
Trust unit issue costs		(44)	(170)	(66)	(6,110)
Cash distributions to unitholders		(8,146)	(7,468)	(23,874)	(18,301)
Change in non-cash working capital		(860)	2,568	(860)	2,568
Deferred financing charges		(94)	(3)	(156)	(258)
Net cash used in financing activities		**$ 2,049**	**$ 9,985**	**$ 1,786**	**$ 119,198**
Net increase (decrease) in cash and cash equivalents		**(81)**	**(1,827)**	**(1,569)**	**(1,518)**
Effects of exchange rates on cash and cash equivalents		(143)	(1,767)	47	(924)
Cash at beginning of the period		2,709	8,647	4,007	7,495
Cash at end of the period		**$ 2,485**	**$ 5,053**	**$ 2,485**	**$ 5,053**

The notes are an integral part of these condensed financial statements.

Eagle Energy Trust

Notes to Condensed Consolidated Financial Statements (unaudited)

For the three and nine months ended September 30, 2013 and September 30, 2012
(in Canadian dollars)

1. Reporting entity / Structure of the Trust

Eagle Energy Trust's activities are restricted to owning property (other than real property or interests in real property), and it does not carry on business. Eagle Energy Trust's subsidiaries are in the business of acquiring, developing and producing petroleum reserves in the United States. Eagle Energy Trust was formed as an unincorporated open-ended limited purpose trust established under the laws of the Province of Alberta on July 20, 2010. The beneficiaries of the Trust are the unitholders.

Throughout these notes to the condensed consolidated financial statements, Eagle Energy Trust and its subsidiaries are referred to collectively as the "Trust" or "Eagle" for purposes of convenience.

The strategy of the Trust is to invest in operating subsidiaries that will acquire on-shore petroleum reserves and production in certain regions of the United States. The Trust's subsidiaries do not intend to engage substantively in exploration activities. The Trust intends to make monthly distributions of a portion of its available cash to unitholders and use the remainder of its available cash to reinvest in its subsidiaries to fund growth through additional acquisitions and capital expenditures. Cash flow is provided to the Trust from properties owned and operated by an indirectly owned subsidiary of the Trust.

Operations officially commenced on November 24, 2010, concurrent with the closing of its first acquisition.

The address of the Trust is: Suite 2710, 500 - 4th Avenue SW, Calgary, AB T2P 2V6.

2.1. Basis of preparation

Basis of accounting

The condensed consolidated financial statements were authorized for issuance in accordance with a resolution of the Board of Directors made on November 7, 2013.

These condensed consolidated interim financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of interim financial statements, including IAS 34, Interim Financial Reporting, and have been prepared following the same accounting policies as the Trust's annual audited IFRS Consolidated Financial Statements for the year ended December 31, 2012, except for the changes described in note 2.2 and income tax expense for an interim period, which is based on an estimated average annual effective income tax rate. The condensed consolidated interim financial statements should be read in conjunction with the annual financial statements for the year ended December 31, 2012, which have been prepared in accordance with IFRS as issued by the IASB.

2.2. Adoption of new and revised standards

The accounting policies followed in these condensed consolidated interim financial statements are consistent with those of the previous financial year, except as described below.

The Trust has adopted the following new and revised standards, along with any consequential amendments, effective January 1, 2013. These changes were made in accordance with the applicable transitional provisions.

- IAS 1, Presentation of Financial Statements. The Trust has adopted the amendments to IAS 1 effective January 1, 2013. These amendments required the Trust to group other comprehensive income items by those that will be reclassified subsequently to profit or loss and those that will not be reclassified. The Trust has reclassified comprehensive income items of the comparative period. These changes did not result in any adjustments to other comprehensive income or comprehensive income.

- IFRS 10, Consolidated Financial Statements, replaces the guidance on control and consolidation in IAS 27, Consolidated and Separate Financial Statements, and SIC-12, Consolidation – Special Purpose Entities. The Trust assessed its consolidation conclusions on January 1, 2013 and determined that the adoption of IFRS 10 did not result in any change in the consolidation status of any of its subsidiaries.

- IFRS 11, Joint Arrangements, supersedes IAS 31, Interests in Joint Ventures, and requires joint arrangements to be classified either as joint operations or joint ventures depending on the contractual rights and obligations of each investor that jointly controls the arrangements. The Trust has classified its joint arrangements and concluded that the adoption of IFRS 11 did not result in any changes in the accounting for its joint arrangements.

- IFRS 13, Fair Value Measurement, provides a single framework for measuring fair value. The measurement of the fair value of an asset or liability is based on assumptions that market participants would use when pricing the asset or liability under current market conditions, including assumptions about risk. The Trust adopted IFRS 13 on January 1, 2013 on a prospective basis. The adoption of IFRS 13 did not require any adjustments to the valuation techniques used by the Trust to measure fair value and did not result in any measurement adjustments.

- IAS 19, Employee Benefits (amended in 2011), amends certain accounting requirements for defined benefits plans and termination benefits. These changes do not impact the Trust and it did not result in any adjustments to the Financial Statements.

3. Financial risk management

The Trust’s activities expose it to a variety of financial risks that arise as a result of its exploration, development, production and financing activities such as:

- credit risk;
- liquidity risk; and
- market risk.

This note presents information about significant changes in the Trust’s exposure to each of the above risks since the year ended December 31, 2012.

Market risk

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates will affect the Trust’s income or the value of the financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters while optimizing the return.

The Trust may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors.

Commodity price risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only the relationship between the Canadian and United States dollar but also world economic events that dictate the levels of supply and demand.

The Trust enters into certain financial derivative instruments periodically to economically hedge some oil and natural gas sales through the use of various financial derivative forward sales contracts and physical sales contracts. The Trust does not apply hedge accounting for these contracts. The Trust’s production is either sold using “spot” or near term contracts, with prices fixed at the time of transfer of custody or on the basis of a monthly average market price or by way of fixed term, fixed price marketing contracts.

As at September 30, 2013, the Trust has entered into the following financial contracts to mitigate the effects of fluctuating prices on a portion of its production as follows:

1. A fixed contract to sell 500 bbls of oil per day with a May 2013 through December 2013 term at a price of $US 103.45 per barrel.

2. A fixed contract to sell 400 bbls of oil per day with a January 2014 through December 2014 term at a price of $US 98.00 per barrel.

3. A costless collar contract for 800 bbls of oil per day with a September 2013 through December 2013 term at a floor of $US 95.00 per barrel and a ceiling of $US 103.75 per barrel.

4. A call swaption to sell 500 bbls of oil per day with a January 2014 through December 2014 term at a price of $US 100.00 per barrel.

5. A fixed contract to sell 300 bbls of oil per day with a February 2013 through December 2013 term at a price of $US 93.25 per barrel.

6. A fixed contract to sell 500 bbls of oil per day with a January 2014 through December 2014 term at a price of $US 91.15 per barrel.

7. A fixed contract to sell 400 bbls of oil per day with a January 2014 through December 2014 term at a price of $US 91.15 per barrel.

Summary of Unrealized Risk Management Positions as at September 30, 2013

	Volume	***Measure***	***Beginning***	***Term***	***Floor $US***	***Ceiling $US***	***Current net present value (NPV) $000's $CA***	***Non-current net present value (NPV) $000's $CA***
Oil Fixed Price								
NYMEX (i)	500	bbls/d	May-13	Dec-13	103.45	103.45	89	
NYMEX (i)	400	bbls/d	Jan-14	Dec-14	98.00	98.00	185	215
NYMEX (ii)	800	bbls/d	Sep-13	Dec-13	95.00	103.75	(66)	
NYMEX (iii)	500	bbls/d	Jan-14	Dec-14	100.00	100.00	(227)	(77)
NYMEX (i)	300	bbls/d	Feb-13	Dec-13	93.25	93.25	(236)	
NYMEX (i)	500	bbls/d	Jan-14	Dec-14	91.15	91.15	(729)	(55)
NYMEX (i)	400	bbls/d	Jan-14	Dec-14	91.15	91.15	(584)	(44)
							$ (1,568)	**$ 39**

(i) Represents a fixed price financial swap transaction with a set forward sale price (WTI reference prices).
(ii) Represents costless collar transactions created by buying puts and selling calls (WTI reference prices).
(iii) Represents a call swaption financial transaction with a set forward sale price (WTI reference prices).

The total net fair value of Eagle's unrealized risk management positions at September 30, 2013 is a liability of $1,529,418 (December 31, 2012 - $2,190,308 asset) and has been calculated using both quoted prices in active markets and observable market-corroborated data consistent with a Level 2 valuation.

Earnings Impact of Realized And Unrealized Risk Management Gain

	Three Months Ended September 30, 2013			Three Months Ended September 30, 2012		
$000's	Realized loss (gain)	Unrealized loss (gain)	Total net loss (gain)	Realized loss (gain)	Unrealized loss (gain)	Total net loss (gain)
Net effect - risk management	**$ 920**	**$ 3,795**	**$ 4,715**	$ (26)	$ 3,853	$ 3,827

	Nine Months Ended September 30, 2013			Nine Months Ended September 30, 2012		
$000's	Realized loss (gain)	Unrealized loss (gain)	Total net loss (gain)	Realized loss (gain)	Unrealized loss (gain)	Total net loss (gain)
Net effect - risk management	**$ 711**	**$ 3,772**	**$ 4,483**	$ 23	$ (2,468)	$ (2,445)

4. Acquisition

Acquisition - Non-financial forward purchase contract

On April 22, 2013, the Trust announced that it had acquired all of the remaining interest in its oil and natural gas properties in the Permian Basin (the "Acquisition") located near Midland, Texas for cash consideration of $8,830,103 which includes closing adjustments of $62,592. The Acquisition had an effective date of January 1, 2013. The Trust now owns 100% working interest in its Midland area properties.

The Acquisition was made pursuant to the terms and conditions of the April 30, 2012 purchase and sale agreement for the Trust's initial acquisition of its interest in the Midland area properties, which closed on May 18, 2012. The terms of the purchase and sale agreement provided the Trust with the right and obligation to purchase the seller's remaining 7.5% undivided interest by April 30, 2013 based on the net present value of such assets as of January 1, 2013, as determined in an independent engineering report.

Consideration was comprised of cash. The acquisition has been accounted for as a business combination with the fair value of the net assets (preliminary purchase price allocation) as follows:

Identifiable assets acquired and liabilities assumed ($CAD):		
Oil and gas properties	$	8,914
Decommissioning liabilities		(84)
	$	**8,830**

5. Operating segments

The operations of the Trust consist of one operating segment: oil and gas exploration, development and the sale of hydrocarbons and related activities. All of the Trust's assets and liabilities, income and expenses relate to this segment and the relevant disclosures have been made elsewhere in these financial statements.

Geographical information

The Trust's operational activities are wholly focused in the continental United States, currently in the state of Texas, and are supported by offices in Houston, Luling, and Midland. The Trust's head office is in Calgary, Alberta. All inter-segment and geographical transactions have been eliminated in consolidation.

Revenue

All of the Trust's revenue from external customers is derived from its operations in the United States.

Non-Current Assets

Substantially all of the Trust's non-current assets are within the United States.

6. Unit-based payments

The following table reconciles unit-based compensation expense.

$ 000's	Note	**Three Months Ended September 30, 2013**	Three Months Ended September 30, 2012	**Nine Months Ended September 30, 2013**	Nine Months Ended September 30, 2012
Units issued on performance option surrender	6(a)	151	546	270	1,280
Restricted unit rights	6(b)	892	612	841	1,519
Unit options	6(c)	2,411	1,006	3,344	2,211
Unit rights	6(d)	486	168	881	320
Total unit-based compensation expense		**$ 3,940**	$ 2,332	**$ 5,336**	$ 5,330

The following table reconciles the unit-based payments liability.

$ 000's	Note	**September 30, 2013**	December 31, 2012
Units issued on performance option surrender	6(a)	-	589
Restricted unit rights	6(b)	1,485	1,588
Unit options	6(c)	7,326	3,982
Unit rights	6(d)	1,272	470
Total unit-based payments liability		**$ 10,083**	$ 6,629

Note (a)

Units issued upon surrender of performance options

At September 30, 2013, no escrowed units were outstanding. On November 24, 2010, the Trust issued and placed into escrow 387,500 units upon surrender of performance options. Two-thirds of those escrowed units were released on September 14, 2012 and the remaining one-third were released from escrow on September 14, 2013. The fair value estimate associated with the escrowed units was expensed in the income statement over the escrow period, which is the same period as the performance conditions, with the offsetting entry to unit-based payments liability. Upon release of the units from escrow, the accumulated liability was then transferred to Trust capital.

The following schedule shows the continuity of escrowed units issued upon surrender of performance options:

	Nine Months Ended September 30, 2013	Year Ended December 31, 2012
Balance, beginning of period	105,417	387,500
Issued	-	-
Transferred to the Trust capital account	(105,417)	(282,083)
Balance, end of period in escrow	**-**	105,417

Note (b)

Cash settled Restricted Unit Rights (RURs) issued upon surrender of performance options

As of September 14, 2013, the remaining one-third of the RURs vested and $613,000 of accumulated vested amounts related to this tranche was paid to the RUR holders.

For the nine months ended September 30, 2013, $944,716 has been paid to the RUR holders (year ended December 31, 2012 - $1,086,248, nine months ended September 30, 2012 – $958,925).

The following schedule shows the continuity of cash settled RURs issued upon surrender of performance options:

	Nine Months Ended September 30, 2013	Year Ended December 31, 2012
Balance, beginning of period	632,500	775,000
Issued	-	-
Forfeited	-	(142,500)
Balance, end of period	632,500	632,500
Number of RURs vested	632,500	421,667

The fair value of the RURs was estimated using the Black-Scholes valuation model with the following inputs:

	September 30, 2013	December 31, 2012
Fair value at the balance sheet date	$ 5.85	$ 4.48
Volatility	32%	32%
Life of RURs	7.3 years	8.0 years
Risk-free interest rate	2.66%	1.82%

A forfeiture rate of 5% was used and this figure is an estimated expected rate. Given the limited trading history of the Trust, which commenced trading on November 24, 2010, a representative sample of peer group entities was used in order to determine expected unit price volatility.

Note (c)

Unit option plan

The number and weighted average exercise prices of unit options are as follows:

	Nine Months Ended September 30, 2013		Year Ended December 31, 2012	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Outstanding, beginning of period	2,214,668	$ 8.23	1,706,000	$ 8.88
Forfeited	(249,918)	4.40	(258,332)	8.32
Exercised	-	-	-	-
Granted	717,000	6.19	767,000	9.15
Outstanding at end of period	**2,681,750**	**$ 7.15**	2,214,668	$ 8.23
Exercisable at end of period	**976,259**	**$ 7.39**	992,006	$ 7.85

The range of exercise prices of the outstanding options is as follows at September 30, 2013:

	Weighted average exercise price	Weighted average contractual life (years)
$6.18 - $8.48	**$ 7.15**	**8.3**

The fair value of the options was estimated using the Black-Scholes model with the following inputs:

	September 30, 2013	December 31, 2012
Fair value - at balance sheet date	$ 4.07	$ 2.93
Unit trading price - closing	$ 8.57	$ 7.69
Exercise price – weighted average	$ 7.15	$ 8.23
Volatility	32%	32%
Option life – weighted average	8.3 years	8.6 years
Distributions – none estimated, due to declining strike price feature	0%	0%
Risk-free interest rate	2.66%	1.82%

A forfeiture rate of 5% was used and this figure is an estimated expected rate. Given the limited trading history of the Trust, which commenced trading on November 24, 2010, a representative sample of peer group entities was used in order to determine expected unit price volatility.

Note (d)

Unit Rights (URs) plan

For the nine months ended September 30, 2013, $78,668 has been paid to the UR holders (year ended December 31, 2012 - $nil, nine months ended September 30, 2012 - $nil).

The following schedule shows the continuity of cash settled URs issued:

	Nine Months Ended September 30, 2013	Year Ended December 31, 2012
Balance, beginning of period	493,000	185,000
Issued	350,000	338,000
Forfeited	(145,000)	(30,000)
Balance, end of period	698,000	493,000
Number of unit rights vested	**147,670**	51,670

The Black-Scholes valuation model is used to determine the fair value of the URs issued by the Trust. The fair value of the URs was estimated using the following inputs:

	September 30, 2013	December 31, 2012
Fair value at the balance sheet date	$ 4.29	$ 2.66
Volatility	32%	32%
Life of URs	9.1 years	9.3 years
Risk-free interest rate	2.66%	1.82%

A forfeiture rate of 5% was used and this figure is an estimated expected rate. Given the limited trading history of the Trust, which commenced trading on November 24, 2010, a representative sample of peer group entities was used in order to determine expected unit price volatility.

7. Finance expense

$ 000's	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Interest expense on long-term debt	522	383	1,337	570
Amortization of deferred financing costs	64	94	180	42
Standby and bank fees	17	24	46	83
Accretion of decommissioning provision	17	8	42	17
Finance expense	$ 620	$ 509	$ 1,605	$ 712

8. Taxation

Reconciliation of effective tax rate

The income tax provision differs from the expected amount calculated by applying the Trust's combined federal and state income tax rate of 35% as follows:

$ 000's		Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Earnings (loss) before taxation		$ (3,241)	$ (2,510)	$ 4,758	$ 6,521
Expected tax rate		35%	35%	35%	35%
Expected income tax provision (recovery)		(1,134)	(878)	1,665	2,282
Decrease (Increase) resulting from:					
Non-deductible items – permanent differences					
Administrative expenses of the Trust	35%	247	174	685	518
Unit-based compensation (recovery)	35%	1,380	816	1,868	1,865
Foreign exchange gain, net	35%	-	52	-	-
Risk management gain	35%	-	2,195	-	-
Changes in temporary differences for which no amounts are recognized	35%	892	(3,035)	(1)	(1,601)
Changes in temporary differences for which amounts are recognized	35%	-	637	-	374
Items deductible at the subsidiary level					
Interest on internal debt of subsidiary	35%	(1,393)	(1,394)	(4,135)	(3,462)
Other	35%	8	18	(82)	24
Total income tax expense (recovery)	35%	$ -	$ (1,415)	$ -	$ -

Deferred tax assets and liabilities:

Deferred tax assets and liabilities are attributable to the following items:

$ 000's	September 30, 2013	December 31, 2012
Deferred tax liabilities		
Oil and gas properties in excess of tax value	$ 22,052	$ 17,989
Exploration and evaluation assets	-	-
	22,052	17,989
Less deferred tax assets:		
Non-capital losses – US based	(25,468)	(20,562)
Net deferred tax liability (asset) – before valuation allowance	(3,416)	(2,573)
Unrecognized deferred tax asset	3,416	2,573
Net deferred tax liability (asset)	$ -	$ -

9. Earnings (Loss) per unit

$ 000's	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Earnings (Loss) basic and diluted	$ (3,241)	$ (1,095)	$ 4,758	$ 6,521
Weighted average units outstanding - basic and diluted	31,004	28,156	30,282	23,276
Earnings (Loss) per unit - basic and diluted	**$ (0.10)**	**$ (0.04)**	**$ 0.16**	**$ 0.28**

Calculation

Basic earnings per unit is calculated by dividing the earnings attributable to unitholders of the Trust by the weighted average number of units outstanding during the period. Diluted earnings per unit is calculated using the income for the period divided by the weighted average number of units outstanding assuming the conversion of potentially dilutive equity instruments outstanding.

Per unit amounts

Diluted income per unit is equal to basic income per unit as it was determined that the conversion of potentially dilutive equity instruments would be anti-dilutive.

10. Oil and gas properties

$ 000's		Developed oil and gas assets		Production facilities and equipment		Capitalized future decom-missioning costs		Total
Cost								
At December 31, 2012	$	304,175	$	6,962	$	1,715	$	312,852
Additions		48,198		587		531		49,316
At September 30, 2013	**$**	**352,373**	**$**	**7,549**	**$**	**2,246**	**$**	**362,168**
Accumulated depreciation and impairment								
At December 31, 2012	$	(41,184)	$	(2,435)	$	-	$	(43,619)
Depreciation		(22,465)		(1,281)		-		(23,746)
At September 30, 2013	**$**	**(63,649)**	**$**	**(3,716)**	**$**	**-**	**$**	**(67,365)**
Net book value								
At December 31, 2012	$	262,991	$	4,527	$	1,715	$	269,233
Net change for the period		25,733		(694)		531		25,570
At September 30, 2013	**$**	**288,724**	**$**	**3,833**	**$**	**2,246**	**$**	**294,803**

The Trust does not capitalize general and administrative costs. Future development costs related to proved plus probable reserves of $87,817,319 (December 31, 2012 - $117,479,500) were included in the depletion calculation.

11. Property, plant and equipment

$ 000's		Furniture, fixtures and equipment		Computer equipment		Vehicles and other		Total
Cost								
Opening Balance	$	60	$	299	$	81	$	440
Additions		72		139		2		213
At September 30, 2013	**$**	**132**	**$**	**438**	**$**	**83**	**$**	**653**
Accumulated Depreciation								
Opening Balance	$	(5)	$	(137)	$	(15)	$	(157)
Depreciation		(27)		(109)		(13)		(149)
At September 30, 2013	**$**	**(32)**	**$**	**(246)**	**$**	**(28)**	**$**	**(306)**
Net book value								
Opening Balance	**$**	55	$	162	$	66	$	283
Net change		45		30		(11)		64
At September 30, 2013	**$**	**100**	**$**	**192**	**$**	**55**	**$**	**347**

12. Distributions payable

$ 000's		**September 30, 2013**		December 31, 2012
Beginning balance	$	2,570	$	1,656
Distributions declared		24,058		26,816
Less distributions paid		(23,874)		(25,902)
Outstanding distributions declared and payable	**$**	**2,754**	$	2,570

Distributions are declared and paid monthly. The outstanding balance at September 30, 2013 represents the distribution declared September 16, 2013 and paid October 23, 2013. The outstanding balance at December 31, 2012 represents the distributions declared December 17, 2012 and paid January 23, 2013.

13. Long-term debt

As at September 30, 2013, $CA 52.8 million has been drawn under the $US 61 million credit facility by way of LIBOR borrowing and base rate loans. For the nine month period ended September 30, 2013, the interest rate was 3.8%.

At September 30, 2013, there were no covenant violations.

As a result of the October 1 semi-annual review, the borrowing base was increased from $US 61 million to $US 70 million. Additionally, the credit agreement was amended to extend the term from December 21, 2014 to May 29, 2015. Refer to note 19 "Subsequent events".

14. Decommissioning liability

$000's		**September 30, 2013**		December 31, 2012
Beginning Balance	$	1,744	$	502
Acquisition		83		709
Additions		396		666
Changes in estimates		-		(158)
Abandonment expenditures		(9)		-
Accretion (unwinding of discount)		42		25
Effects of exchange rate		62		-
Ending Balance	**$**	**2,318**	$	1,744

The decommissioning provision reflects the present value of internal estimates of future decommissioning costs of the Trust's net ownership position in oil and gas wells and related facilities at the relevant balance sheet date determined using local pricing conditions and requirements. These costs are expected to be incurred between 2014 and 2063. The timing of payments related to provisions is uncertain and is dependent on various items which are not always within Management's control.

The provision was estimated using existing technology, at current prices (adjusted for inflation assuming 2% inflation rate), and discounted using a risk-free discount rate of 3% at September 30, 2013 (September 30, 2012 – 2%).

15. Trust capital

Trust units outstanding	September 30, 2013			December 31, 2012		
$000's	Number of units		Amount	Number of units		Amount
Beginning balance	29,269	$	276,526	18,544	$	168,175
Issuance of Trust capital pursuant to DRIP	2,095		14,978	1,763		16,435
Issuance of Trust units[(i)]	-		-	8,680		95,480
Units released from escrow	105		859	282		2,779
Trust unit issuance costs			(66)	-		(6,343)
Ending balance	**31,469**	**$**	**292,297**	29,269	$	276,526

(i) Issued in conjunction with the asset acquisition which closed May 18, 2012.

For the nine months ended September 30, 2013, the Trust incurred $66,364 (December 31, 2012 - $261,368) of unit issuance costs in conjunction with implementing the unit distribution reinvestment program ("DRIP").

16. Cash generated from operations

$ 000's		**Three Months Ended September 30, 2013**		Three Months Ended September 30, 2012		**Nine Months Ended September 30, 2013**		Nine Months Ended September 30, 2012
Income (loss) for the period	**$**	**(3,241)**	$	(1,095)	**$**	**4,758**	$	6,521
Adjustments for:								
Depreciation, depletion and amortization		7,839		6,221		22,412		16,906
Income tax expense - deferred		-		(1,415)		-		-
Unit-based compensation – non-cash portion		3,141		1,373		4,313		4,371
Unrealized risk management (gain) loss		3,795		3,853		3,772		(2,468)
Finance expense		81		102		222		60
		11,615		9,039		**35,477**		25,390
Changes in working capital:								
Trade and other receivables		(6)		(626)		981		(2,034)
Prepaid expenses		(173)		(322)		(26)		(166)
Trade and other payables		(2,626)		(3,873)		(2,040)		4,324
		(2,805)		(4,821)		**(1,085)**		2,124
Cash (used in) generated from operations	**$**	**8,810**	$	4,218	**$**	**34,392**		27,514
Abandonment expenditures		-		-		(9)		-
Income taxes paid		-		-		-		-
Net cash generated by operating activities	**$**	**8,810**	$	4,218	$	**34,383**	$	27,514

Summary of non-cash items ($ 000's)

$ 000's	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Operating cash flow				
Income tax expense - deferred	$ -	$ (1,415)	$ -	$ -
Unit-based compensation	3,141	1,373	4,313	4,371
Distributions payable - declared not yet paid	2,754	2,519	2,754	2,519
Unrealized risk management (gain) loss	3,795	3,853	3,772	(2,468)
Investment activities				
Depreciation, depletion and amortization	$ 7,839	$ 6,221	$ 22,412	$ 16,906
Provision for decommissioning costs	47	81	574	1,188
Accretion of decommissioning provision	17	8	42	17
Financing activities				
Finance expense-amortization of deferred financing costs	$ 65	$ 94	$ 180	$ 44
Distributions accrued - declared not yet paid	(2,754)	(2,519)	(2,754)	(2,519)

17. Related party disclosures

The Trust has no party holding voting control.

Key management

Key management personnel includes the Trust's Chief Executive Officer, Chief Financial Officer, Chief Operating Officer, Vice-President Business Development, Vice-President Finance, General Counsel/Corporate Secretary and the Directors.

Intercompany transactions

There are certain intercompany transactions among the subsidiaries comprising these consolidated financial statements of the Trust. These transactions have been eliminated in consolidation.

18. Commitments

Operating lease commitment – head office lease in Calgary, Alberta

On January 1, 2013, the Trust entered into a head-lease agreement for new office space which has an approximate 61 month term from January 8, 2013 to February 7, 2018. Future minimum lease payments during the term of the lease approximate $2.1 million and include an available leasehold improvements allowance of $0.3 million, with 52 months and approximately $1.8 million remaining at September 30, 2013.

Operating lease commitment – office lease in Houston, Texas

The lease agreement was entered into on April 1, 2011, and originally had an approximate 30 month term from April 7, 2011 through September 30, 2013. On November 21, 2012, the lease agreement was extended for an additional 63 month period from October 1, 2013 to December 31, 2017 and the premise space was expanded to incorporate additional square footage. Future minimum lease payments during the term of the lease include an available leasehold improvement allowance of $US 111,293 and approximate $US 1.5 million, with 51 months and approximately $US 1.1 million remaining at September 30, 2013. In $CA the remaining future minimum lease payments approximate $1.2 million translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.03.

Operating lease commitment – office lease in Luling, Texas

The lease agreement was entered into on August 15, 2011, and originally had an approximate 12 month term from August 15, 2011 through August 31, 2012. On April 24, 2012, the lease agreement was extended for an additional 36 month period from September 1, 2012 to August 31, 2015 at a monthly rate of $US 1,650. Future minimum payments during the term of the sublease and the extension approximate $US 80,000, with 23 months and approximately with $US 38,000 remaining at September 30, 2013. In $CA, the remaining future minimum lease payments approximate $39,000 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.03.

Operating lease commitment – office lease in Midland, Texas

The lease agreement was entered into on July 31, 2012 and has an approximate 48 month term from October 15, 2012 through October 14, 2016. Future minimum lease payments during the term of the lease approximate $US 203,000 with 36 months and approximately $US 152,000 remaining at September 30, 2013. In $CA the remaining future minimum lease payments approximate $157,000 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.03.

Software data base

A three year subscription agreement for technical software was entered into effective June 18, 2013. The total subscription commitment was estimated to be approximately $US 0.4 million, with approximately $US 0.3 million remaining at September 30, 2013. In $CA, the net future commitment approximates $0.3 million translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 1.03.

19. Subsequent events

Increase in Eagle Energy Acquisitions LP borrowing base

Effective October 17, 2013, the borrowing base under the credit facility was increased from $US 61 million to $US 70 million. Additionally, the credit agreement was amended to extend the term from December 21, 2014 to May 29, 2015. All other terms and conditions remain unchanged.

Acquisition

On November 4, 2013, the Trust announced its U.S. subsidiary had signed a purchase and sale agreement to acquire producing properties in Hardeman County, Texas for a purchase price of $US 26.3 million, subject to closing adjustments. The seller's current working interest production from the properties is approximately 300 boe per day, consisting of 97% light sweet crude (43° API) from 34 producing wells. The acquisition is expected to close on or about November 25, 2013, with an effective date of October 1, 2013. In addition, upon successful closing of this acquisition, Eagle's lenders have approved a further increase in Eagle's credit facility to $US 90.0 million consisting of a $US 80.0 million revolving facility and a new one year non-revolving credit facility of $US 10.0 million. The Trust intends to use an advance under this new credit facility to fund the acquisition.

Corporate Information

Board of Directors

David M. Fitzpatrick
Chairman of the Board

Bruce K. Gibson (1)
Director

Warren D. Steckley (2)
Director

Joseph W. Blandford (3)
Director

Richard W. Clark
President, Chief Executive Officer and Director

(1) Audit Committee Chair
(2) Reserves & Governance Committee Chair
(3) Compensation Committee Chair

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Officers

Richard W. Clark
President, Chief Executive Officer and Director

Kelly A. Tomyn
Chief Financial Officer

J. Wayne Wisniewski
Chief Operating Officer

Robert J. Cunningham
Vice President, Business Development

James D. Elliott
Vice President, Finance

Jo-Anne M. Bund
General Counsel/Corporate Secretary

Auditors

PricewaterhouseCoopers LLP

Trustee and Transfer Agent

Computershare Trust Company of Canada

Engineering Consultants

GLJ Petroleum Consultants Ltd.
Netherland Sewell and Associates, Inc.

Bankers

Bank of Nova Scotia

Legal Counsel

Bennett Jones LLP

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