VISION GROWTH INCOME

First Quarter 2013 Financial Report

EAGLE ENERGY™
TRUST

Management's Discussion and Analysis

May 9, 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 May 9, 2013, should be read in conjunction with the Trust's unaudited interim condensed consolidated financial statements and accompanying notes for the three months ended March 31, 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**"), located near Midland, Texas. After the closing, Eagle also acquired all of another party's 1% interest in the same properties. Subsequent to March 31, 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 months ended March 31, 2013

- First quarter 2013 average working interest sales volumes of 2,928 barrels of oil equivalent per day (“boe/d”) exceeded Eagle’s first quarter plan and were unchanged from fourth quarter 2012 production levels.
- Eagle maintained fourth quarter 2012 production levels throughout the first quarter of 2013 while spending less than 20% of its 2013 capital budget. Over 60% of Eagle’s 2012 capital program occurred in the last half of 2012, resulting in a substantial portion of fourth quarter 2012 production from new wells being comprised of normal flush production. Eagle’s first quarter 2013 results demonstrate both improved operations execution as well as a significantly lower corporate decline rate compared to market consensus regarding prior periods.
- Average working interest production was 2,928 boe/d (87% oil, 7% natural gas liquids, 6% natural gas). From this base, the Trust remains on track to meet its 2013 full year production guidance of 2,900 to 3,100 boe/d. Eagle commenced its 2013 drilling program in April.
- Achieved a 37% reduction in field operating costs (excluding transportation) compared to first quarter 2012, and a 20% reduction compared to the fourth quarter 2012. Total field operating costs, including transportation, were $11.18 per boe. The significant reduction was primarily due to improved operating procedures, including reducing salt water disposal costs, resizing submersible pumps and negotiating lower power contracts.
- 2013 funds flow from operations was $11.9 million, up 30% from the first quarter of 2012 and up 20% from the fourth quarter of 2012.
- Top-decile first quarter field netbacks were $52.59 per boe. Canadian dollar realized oil prices were 103% of benchmark $US WTI. Premium pricing negotiated by Eagle in its 2013 marketing arrangements contributed to top decile per boe field and operating netbacks, giving Eagle a substantial revenue advantage over producers of Canadian oil.
- First quarter distributions held steady at $0.26 per unit or $0.0875 per unit per month without increasing debt per unit from the fourth quarter 2012.
- On April 22, 2013, Eagle acquired the remaining 7.5% interest in its oil and natural gas properties in the Permian Basin located near Midland for cash consideration of approximately $US 8.5 million (the “**Acquisition**”). The Acquisition adds approximately 70 boe/d of production. The Trust now owns 100% working interest these properties.
- Upon completion of the 2012 year end reserves report and the closing of the Acquisition, the borrowing base under Eagle’s credit facility was increased from $US 48.5 million to $US 61.0 million. The credit facility was syndicated to include a second major Canadian chartered bank as a new lender.

Outlook

This outlook section is intended to provide unitholders with information about Eagle’s expectations as at the date hereof for production 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".

2013 Updated guidance

Following completion of the Acquisition, the Trust updated its guidance as set forth below.

	Updated 2013 Guidance	Previous 2013 Guidance	Notes
Capital Budget	$US 26.0 mm	$US 24.0 mm	(1)
Working Interest Production	2,900 – 3,100 boe/d	2,900 – 3,100 boe/d	(2)
Operating Costs (inclusive of transportation)	$12.00 - $14.00 per boe	$12.00 - $14.00 per boe	(2)
Funds Flow from Operations	$45.0 mm	$41.0 mm	(3)

Notes:

(1) Increase due to the Acquisition. Eagle now owns a 100% working interest in its Midland properties. Note that the capital budget amount excludes the initial $US 8.5 million cost of the Acquisition.

(2) The April 22, 2013 Acquisition is expected to add approximately 70 boe/d to production volumes. This results in no change to previously stated production range guidance or operating cost guidance.

(3) 2013 funds flow from operations of $45.0 million (previous funds flow guidance of $41.0 million) has been estimated using the following assumptions:

a. based on actual results through to March 31, 2013 and the Acquisition;

b. full year average working interest production of 3,100 boe/d, which is at the upper end of the guidance range (previous funds flow guidance assumption used 3,000 boe/d, which was at the mid-point of the guidance range);

c. April - December benchmark pricing unchanged from previous funds flow guidance assumptions: $US 90.00 per barrel West Texas Intermediate ("WTI") oil, $US 2.90 per Mcf NYMEX gas and $US 39.60 per barrel NGLs (NGLs price is calculated as 44% of the WTI price);

d. April - August field marketing contracts currently in place for both Midland and Luling, as described in the "Revenue" section of this MD&A;

e. September - December $2.23 per barrel discount from WTI in Midland (excluding transportation) and a $1.71 per barrel discount from WTI in Luling (excluding transportation), which is based on assumptions used in the latest reserve report since no field marketing contracts yet are in place for this period;

f. April - December average operating costs (inclusive of transportation) unchanged from previous funds flow guidance assumption of $13.00 per boe; and

g. April - December foreign exchange unchanged from previous funds flow guidance assumption 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.

	Revised 2013 Guidance	Previous 2013 Guidance	Notes
Payout Ratios (as a percentage of funds flow)			
Basic Payout Ratio (i.e., Distribution at $1.05/unit)	71%	77%	(1)
Plus: Capital Expenditures	57%	59%	(2)
Equals: Corporate Payout Ratio	128%	136%	(3)
Adjusted Payout Ratio (i.e., Distribution - DRIP proceeds + Capital Expenditures)	83%	85%	(4)
Financial Strength			
Debt to trailing cashflow	0.88x	0.78x	(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 initial acquisition capital of $US 8.5 million relating to the Acquisition has 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 from this method of financing and will make adjustments as deemed prudent.

(5) Increased due to the $US 8.5 million Acquisition being financed by bank debt.

(6) Effective April 22, 2013, the borrowing base under the credit facility was increased to $US 61.0 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 (Apr – Dec) Average WTI		
		$US 80.00	$US 90.00	$US 100.00
2013 Average Working Interest Production (boe/d)	2,900	40.7	42.0	44.1
	3,100	44.1	45.0	48.1
	3,300	47.4	49.4	52.2

Sensitivity of Corporate Payout Ratio to Commodity Price and Production

		2013 (Apr – Dec) Average WTI		
		$US 80.00	$US 90.00	$US 100.00
2013 Average Working Interest Production (boe/d)	2,900	144%	140%	133%
	3,100	133%	128%	122%
	3,300	124%	119%	112%

Sensitivity of Basic Payout Ratio to Commodity Price and Production

		2013 (Apr – Dec) Average WTI		
		$US 80.00	$US 90.00	$US 100.00
2013 Average Working Interest Production (boe/d)	2,900	79%	77%	73%
	3,100	73%	71%	67%
	3,300	68%	65%	62%

Assumptions:

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

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

(3) Field operating costs, including transportation, of $13.00 per barrel.

The Trust remains on track to meet its 2013 guidance and to add additional production with the start of its 2013 capital program, beginning in April with five planned wells at Midland, followed by six planned wells in Luling beginning in June.

The Midland drilling program will continue to target multiple pay zones from the Clearfork through to the Atoka. Several horizontal plays are also being drilled by other operators in the Martin county area. Eagle is focusing on three zones for potential horizontal drilling on its acreage next year. The Salt Flat program will continue to primarily target the Edwards "A" zone; however, the Edwards "B" and "C" zones have also been shown to be productive by the Trust on its acreage. Eagle anticipates further development in these zones as its technical team continues to enhance its understanding of the subsurface.

Acquisition of remaining interest in the Trust's Midland area properties

On April 22, 2013, the Trust's operating subsidiary completed the Acquisition and acquired all of the remaining interest in its oil and natural gas properties in the Permian Basin located near Midland for cash consideration of $US 8.5 million, subject to closing adjustments and effective as of January 1, 2013. The Trust now owns a 100% working interest in its Midland area properties.

The Acquisition was made pursuant to the terms and conditions of the April 2012 purchase and sale agreement for the Trust's initial acquisition of its interest in the Midland area properties. Under the terms of the purchase and sale agreement, the Trust had agreed to purchase the seller's remaining 7.5% undivided interest by April 30, 2013.

Increase to Eagle's credit facility

Effective April 22, 2013, the Trust announced an increase in the borrowing base under its credit facility, with a Canadian chartered bank acting as agent. The borrowing base was increased to $US 61 million from $US 48.5 million. In addition, the credit facility has been syndicated to include a second Canadian chartered bank as a new lender. As of the end of the first quarter 2013, the Trust had 38% undrawn on its expanded credit facility.

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.

	Full year impact on ➔	**Funds flow from operations ($000's)**	**Funds flow from operations / unit**
Gas price[(2)]	+ USD $0.10/mcf Henry HUB	6	0.00
Oil price [(2)]	+ USD $1.00/bbl WTI	191	0.01
Gas production	+1000 mcf/d	171	0.01
Oil production	+100 bbls/d	2,155	0.07
Currency [(2)]	+CDN strengthen by $0.01	(155)	(0.01)
Interest Rate	+1% prime	(98)	(0.00)

Notes:

(1) Per unit figures are based on 29,544,969 weighted average basic units outstanding for the three months ended March 31, 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 2,928 boe per day.

Results of operations

Production

Oil equivalent sales volumes (boe/d @ 6:1)	**Three Months Ended March 31, 2013**	Three Months Ended March 31, 2012
Oil (bbl/d)	2,553	2,169
Natural gas (Mcf/d)	1,019	-
Natural gas liquids (bbl/d)	207	-
	2,928	2,169

Working interest sales volumes for the first quarter of 2013 averaged 2,928 boe/d (87% oil, 7% natural gas liquids, 6% natural gas), a 35% increase from the first quarter of 2012 levels (which was 100% oil). The increase is attributable to the May 2012 Midland area acquisition, 9 (8.2 net) additional oil wells being tied-in in the Midland area and an additional 16 (12.8 net) oil wells being brought on stream in the Luling area since March 31, 2012.

Revenue

($000's)		**Three Months Ended March 31, 2013**		Three Months Ended March 31, 2012
Oil	$	22,412	$	19,174
Natural gas		320		-
Natural gas liquids		609		-
Sales before royalties	**$**	23,341	**$**	19,174

Realized Prices				
Oil ($/bbl)	$	97.55	$	97.16
Natural gas ($/Mcf)		3.49		-
Natural gas liquids ($/bbl)		32.63		-
Sales before royalties ($/boe)		88.57		97.16
Royalties ($/boe)		(24.80)		(26.49)
Revenue ($/boe)	**$**	63.77	**$**	70.67

Benchmark Prices				
Oil – WTI ($US/bbl)	**$**	94.35	**$**	102.84
Natural gas – Henry HUB ($US/Mcf)	**$**	3.34	**$**	N/A

The Trust's quarterly revenue is 99% derived from oil and natural gas liquids. Canadian dollar realized oil prices were 103% of benchmark $US WTI for the quarter while natural gas liquid prices were approximately 35% of benchmark $US WTI.

There is a quality differential between the benchmark WTI price and the $US price realized by the Trust. The Trust enters into marketing contracts in the field to obtain the most favorable pricing. For example, in the Luling area, the Trust had a marketing agreement in place from September 2012 through February 2013 where the Trust's reference price was set to Louisiana Light Sweet instead of WTI. This resulted in a premium to the WTI price of $US 3.53 per barrel (excluding transportation costs). Additionally, from March 2013 through August 2013, the Trust has a marketing agreement in place that sets the Trust's reference price to Louisiana Light Sweet instead of WTI, which results in a premium to the WTI price of $US 4.75 per barrel (excluding transportation costs). In the Midland area, the Trust had a marketing agreement in place from October 2012 through February 2013 which limited the discount from the WTI price to $US 2.36 per barrel (excluding transportation costs). Additionally, from March 2013 through August 2013, the Trust has a marketing agreement in place which limits the discount from the WTI price to $US 2.06 per barrel (excluding transportation costs). Management monitors pricing regularly and endeavors 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.

The benchmark WTI price increased 7% from the fourth quarter 2012, with $US realized prices and Canadian dollar realized prices increasing by a commensurate amount. The above prices do not include realized gains or losses from financial commodity contracts, which amounted to a realized gain of $24,780 ($0.09/boe) for the three months ended March 31, 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 March 31, 2013		Three Months Ended March 31, 2012	
	$	**/boe**	$	/boe
Operating expenses		9.04		14.33
Transportation expenses		2.14		1.98
	$	**11.18**	$	16.31

Fuel, utilities and equipment rentals account for 27% of the operating costs during the first quarter 2013 compared to 53% for the three months ended March 31, 2012. The Trust achieved a 37% reduction in field operating costs (excluding transportation) when compared to first quarter 2012, and a 20% reduction when compared to the fourth quarter 2012. The significant reduction was primarily due to improved operating procedures, including reducing salt water disposal costs, resizing submersible pumps and negotiating lower power contracts.

Depreciation, depletion and amortization

	Three Months Ended March 31, 2013		Three Months Ended March 31, 2012	
	$	**/boe**	$	/boe
Depreciation, depletion and amortization		**27.34**		25.73

The depletion, depreciation, and amortization provision for the three months ended March 31, 2013 was based on proved plus probable reserves, including the future development costs associated with those reserves, as found in the year end 2012 reserves evaluation reports for Salt Flat and Midland, respectively, as prepared by the Trust's independent reserves evaluators.

Field netback

	Three Months Ended March 31, 2013			Three Months Ended March 31, 2012		
($000's)	**$**	**$**	**/boe**	$	$	/boe
Sales before royalties	23,341		88.57	19,175		97.16
Royalties	(6,536)		(24.80)	(5,227)		(26.49)
Operating expenses	(2,383)		(9.04)	(2,828)		(14.33)
Transportation expenses	(565)		(2.14)	(391)		(1.98)
Field netback	**$** 13,857	**$**	52.59	$ 10,729	$	54.36
Sales volumes (boe/d)			**2,928**			2,169

During the quarter, benchmark WTI averaged $US 94.35 per barrel and the Trust realized a field netback of $52.59 per barrel.

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)	300 bbls/d	May 2012 to Apr 2013	$95.00-$108.25
NYMEX (ii)	200 bbls/d	Jan 2013 to Apr 2013	$103.45
NYMEX (ii)	500 bbls/d	May 2013 to Dec 2013	$103.45
NYMEX (ii)	400 bbls/d	Jan 2014 to Dec 2014	$98.00
NYMEX (i)	250 bbls/d	Aug 2012 to Jul 2013	$87.00-$89.70
NYMEX (i)	250 bbls/d	Sep 2012 to Aug 2013	$90.00-$91.60
NYMEX (i)	300 bbls/d	Jan 2013 to Jul 2013	$95.00-$103.75
NYMEX (i)	500 bbls/d	Aug 2013 to Aug 2013	$95.00-$103.75
NYMEX (i)	800 bbls/d	Sep 2013 to Dec 2013	$95.00-$103.75
NYMEX (ii)	300 bbls/d	Feb 2013 to Dec 2013	$93.25
NYMEX (ii)	500 bbls/d	Jan 2014 to Dec 2014	$91.15
NYMEX (iii)	500 bbls/d	Jan 2014 to Dec 2014	$100.00

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

A stronger forward commodity pricing environment since the end of 2012 caused a decrease in the future value of these contracts and a corresponding decrease to the risk management asset on the balance sheet during the first quarter. 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. As a result, there was a $1.8 million unrealized loss for the three months ended March 31, 2013 (March 31, 2012 - $0.9 million unrealized loss). There was a $0.02 million realized risk management gain for the three months ended March 31, 2013 (March 31, 2012 - $0.3 million realized loss).

Administrative expenses

Total administrative expenses for the first quarter were $1.4 million essentially even with first quarter 2012 levels but distributed across a 35% higher production base. Staff and related employment costs account for approximately 70% of administrative expenses.

Unit-based compensation

A $1.2 million recovery of non-cash unit based compensation expense was recorded during the first quarter of 2013 ($4.0 million expense for the three months ended March 31, 2012). This was due to a lower unit price at the end of the first quarter of 2013 when compared to the unit price at 2012 year end and the resulting fair market valuation of such change.

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

The actual total value received by holders of the awards will depend on: (1) the price the escrowed units are eventually sold for by the holders of those units (which would not result in a cash outlay for the Trust), (2) 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 (3) 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 escrowed units, (2) the restricted unit rights, (3) the options and (4) 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. The decrease in the liability and associated recovery from March 31, 2012 to March 31, 2013 was primarily due to the lower year over year price of the Trust's units.

During the first quarter, $0.1 million (three months ended March 31, 2012 - $nil) was paid out in cash for amounts related to vested restricted unit rights and US based unit rights. The liability that was, and continues to be, accrued from inception for these cash settled awards was reduced by such cash payments.

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 areas 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

	Q1/2013	Q4/2012	Q3/2012	Q2/2012	Q1/2012	Q4/2011	Q3/2011	Q2/2011
($000's except for boe/d and per unit amounts)								
Sales volumes – boe/d	2,928	2,986	2,825	2,400	2,169	2,023	995	1,214
Revenue, net of royalties	16,805	16,519	15,181	13,077	13,947	11,798	5,533	7,305
per boe	63.77	60.13	58.41	59.90	70.67	63.40	60.42	66.10
Funds flow from operations	11,884	9,905	9,039	7,233	9,118	7,199	2,432	5,029
per boe	45.10	36.06	34.78	33.13	46.20	38.69	26.55	45.52
per unit – basic	0.40	0.34	0.32	0.31	0.50	0.39	0.14	0.28
per unit – diluted	0.40	0.32	0.32	0.31	0.50	0.39	0.14	0.28
Income (loss)	4,080	(403)	(1,095)	8,567	(952)	(1,426)	421	1,703
per unit – basic & diluted	0.14	(0.02)	(0.04)	0.37	(0.05)	(0.08)	0.02	0.10
Cash distributions declared	7,828	7,653	7,512	6,628	5,024	4,936	4,848	4,775
per issued unit	0.2625	0.2625	0.2625	0.2625	0.2625	0.2625	0.2625	0.2625
Current assets	9,913	14,464	14,209	18,758	16,447	13,385	14,121	20,067
Current liabilities	11,982	17,512	23,723	28,158	20,319	16,557	12,023	7,299
Total assets	283,112	284,802	283,913	291,273	156,477	158,885	164,480	150,351
Total non-current liabilities	39,873	42,111	35,136	27,192	489	503	2,671	4,496
Unitholders' equity	231,257	225,179	225,055	235,923	135,669	141,826	149,785	138,556
Units outstanding for accounting purposes	29,960(1)	29,269(1)	28,654(1)	27,895(1)	18,847(1)	18,544(1)	18,174(1)	17,894(1)
Units issued	30,066	29,375	28,783	28,283	19,234	18,931	18,562	18,282

Note:

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

With the exception of the third quarter of 2011, which had approximately 328 barrels per day of oil temporarily shut in due to delays in obtaining Texas Commission on Environmental Quality permits, production has grown commensurate with well tie-ins and acquisitions. First quarter 2013 volumes stayed level with fourth quarter 2012 volumes since the 2013 drilling program was not scheduled to commence until the second quarter of 2013.

Funds flow from operations increased in the first quarter of 2013, when compared to the prior quarters primarily due to higher commodity prices and lower operating costs. Generally, in times of steady or increasing prices, funds flow from operations grows as sales volumes increase, and on a per-boe basis, will decline when volumes decline, as they did in the third quarter of 2011. 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 those that are required to be fair valued at each quarter end. By way of example, first quarter 2013 funds flow from operations increased 20% from the fourth quarter 2012 while first quarter income increased by a much larger percentage. This occurred for two reasons. First, an impairment charge recorded in the fourth quarter of 2012 reduced income. Second, a lower unit price at the end of the first quarter of 2013 caused a unit based compensation recovery to be recorded upon performing a fair market valuation of future unit based payments.

Liquidity and capital resources

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

Management's objective is 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 March 31, 2013		Three Months Ended March 31, 2012	
($000's)	**$**	**$ /boe**	$	$ /boe
Field netback	13,857	52.59	10,729	54.36
Cash settled award payments	(114)	(0.43)	-	-
Administrative expenses	(1,421)	(5.39)	(1,338)	(6.78)
Realized risk management gain (loss)	24	0.09	(256)	(1.30)
Finance expense	(450)	(1.71)	(27)	(0.13)
Realized foreign exchange gain (1)	(12)	(0.05)	10	0.05
Funds flow from operations	**$ 11,884**	**$ 45.10**	$ 9,118	$ 46.20

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 March 31, 2013, the Trust had approximately $US 11.2 million of unused credit on its $US 48.5 million credit facility, which is held indirectly through its U.S. subsidiary with a U.S. affiliate of a Canadian chartered bank. At December 31, 2012 the Trust had approximately $US 8.0 million of unused credit.

Effective April 22, 2013, the borrowing base under the credit facility was increased to $US 61.0 million. All other terms and conditions remain unchanged. In addition, the credit facility has been syndicated to include a second Canadian chartered bank.

Working capital

At March 31, 2013, the Trust had a working capital deficiency of $2.1 million (which becomes a $2.9 million surplus when the non-cash current portion of unit-based payments and current risk management contracts are excluded) and $37.9 million (December 31, 2012- $40.2 million; March 31, 2012- $nil) drawn on its $US 48.5 million bank credit facility described above.

Unitholders' equity

All Trust capital issuances during the first quarter 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 March 31, 2013, 690,988 units (year ended December 31, 2012 – 591,106 units, three months ended March 31, 2012 – 303,377 units) were issued for total proceeds of approximately $4.9 million (year ended December 31, 2012 - $4.9 million, three months ended March 31, 2012 - $3.1 million) at an average price of $7.06 per unit (year ended December 31, 2012 $8.39 per unit, three months ended March 31, 2012 - $10.24 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. Distributions paid in the first quarter (for the December 2012, and January and February 2013 record dates) totaled approximately $7.8 million.

At March 31, 2013, the Trust had issued 30,065,548 units. For purposes of the March 31, 2013 condensed consolidated interim financial statements, 29,960,131 units were shown as outstanding. The 105,417 difference relates to units previously issued on the surrender of performance options that are excluded from financial statement figures because IFRS principles exclude units that require a performance condition be met before being released from escrow. Distributions are paid on the units while they are in escrow.

As at the date of this MD&A, 30,334,716 units are issued and 2,681,250 options are outstanding.

Capital expenditures

Capital expenditures during the three months ended March 31, 2013 and March 31, 2012 were as follows:

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
(000's)	**$**	$
Exploration and evaluation[1]	19	83
Intangible drilling and completions[2]	3,921	(280)
Well equipment and facilities	179	2,755
Other	50	81
	$ 4,169	$ 2,639

Notes:

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

(2) Lower than expected year end 2011 capital activity resulted in a net credit in first quarter 2012 intangible drilling and completion costs.

During the first quarter of 2013 the Trust spent $3.9 million on drilling and completions. Of this total, $1.0 million was invested on completing and fracturing one well to bring it on production. Another $0.5 million was spent on the commencement of drilling the Trust's first well of the 2013 capital program and $1.9 million was spent to recomplete existing wells.

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 located near Midland, Texas for cash consideration of $US 8,544,500, subject to closing adjustments and effective 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 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.

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]		3,493		634		1,560		1,299
Drilling rig commitment[5][6]		1,600		1,600		-		-
Total contractual obligations	**$**	**5,093**	**$**	**2,234**	**$**	**1,560**	**$**	**1,299**

Notes:

(1) Calgary, Alberta office lease: The monthly rent of the Trust's sub-lease agreement for its former office space was $9,250. On April 1, 2013, the Trust served its 30 day notice of termination of the sub-lease agreement. 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 $2.0 million and include an available leasehold improvements allowance up to $0.3 million, with 58 months and approximately $2.0 million remaining at March 31, 2013.

(2) Houston, Texas office lease: The 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 57 months and approximately $US 1.2 million remaining at March 31, 2013. In $CA the remaining future minimum lease payments approximate $1.3 million translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.016.

(3) Luling, Texas office lease: The 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 with a monthly rate of $US 1,650. Future minimum payments during the term of the sublease and the extension approximate $US 80,000, 29 months and approximately with $US 48,000 remaining at March 31, 2013. In $CA, the remaining future minimum lease payments approximate $49,000 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.016.

(4) Midland, Texas office lease: The 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 42 months and approximately $US 177,000 remaining at March 31, 2013. In $CA the remaining future minimum lease payments approximate $180,000 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.016.

(5) Drilling rig commitment: The Trust through its operations in the Midland area entered into a four well drilling rig commitment with an option to drill two additional wells effective January 17, 2013. Future minimum payments are estimated to be approximately $US 0.9 million, which is 100% of the commitment. The net commitment to the Trust, based upon its approximate 92.5% interest equals to $US 0.8 million, in $CA the net future commitment approximates $0.8 million translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 1.016.

(6) Drilling rig commitment: The Trust, through its operations in the Salt Flat area entered into a six well drilling rig commitment effective April 24, 2013. Future minimum payments are estimated to be approximately $US 0.7 million. In $CA the net future commitment approximates $0.7 million translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 1.016.

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 are therefore unlikely to 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 March 31, 2013	Three Months Ended March 31, 2012
Earnings (Loss)	**$ 4,080**	$ (952)
Add back (deduct) items not involving cash:		
Unit-based compensation – non-cash portion	(1,322)	4,005
Unrealized risk management loss	1,812	930
Depreciation, depletion and amortization	7,249	5,101
Finance expense	65	34
Funds flow from operations	**$ 11,884**	$ 9,118
Add back (deduct) items not directly related to field operations:		
Realized foreign exchange loss (gain)	12	(10)
Finance expense (cash portion)	450	27
Risk management (gain) loss-realized	(24)	256
Administrative expenses	1,421	1,338
Cash settled award payments	114	-
Field netback	**$ 13,857**	$ 10,729

No change in internal controls over financial reporting during the period January 1, 2013 to March 31, 2013

During the period beginning on January 1, 2013 and ended on March 31, 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 first 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 2013 capital budget and specific uses, including the 2013 drilling program;
- the Trust's expectation regarding its average 2013 working interest production, 2013 operating costs and 2013 funds flow from operations;
- the Trust's expectation regarding its 2013 funds flow from operations and sensitivities of funds flow from operations to production rates and commodity prices;
- the Trust's expectation regarding its 2013 payout ratios and debt to trailing cashflow
- the Trust's expectations regarding the percentage to be drawn on its credit facility and specific uses;
- the sensitivities of 2013 payout ratios to changes in production rates and commodity prices; and
- the Trust's expectation regarding the zones to be targeted by its drilling program.

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 rates;
- future production levels;
- 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 US 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 AIF:

- 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;
- 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, Eagle's Premium Drip ™ and distribution reinvestment programs and distributions are subject to change in light of ongoing results, prevailing economic circumstances, obtaining regulatory approvals, 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 months ended March 31, 2013 and March 31, 2012

Eagle Energy Trust

Condensed Consolidated Balance Sheets

(Thousands of Canadian dollars) (unaudited)

	Note		March 31, 2013		December 31, 2012
ASSETS					
Current assets					
Cash		$	2,331	$	4,007
Trade and other receivables			6,758		7,612
Prepaid expenses			520		531
Risk management asset	3		304		2,314
			9,913		**14,464**
Non-current assets					
Risk management asset	3		106		-
Exploration and evaluation			441		422
Oil and gas properties	9		272,005		269,233
Property, plant and equipment	10		293		282
Other intangible assets			354		401
			273,199		**270,338**
Total Assets		**$**	**283,112**	**$**	**284,802**
LIABILITIES					
Current liabilities					
Trade and other payables		$	4,044	$	8,313
Distributions payable	11		2,631		2,570
Unit-based payments	5		5,307		6,629
			11,982		**17,512**
Non-current liabilities					
Risk management liability	3		-		123
Long-term debt	12		37,897		40,244
Deferred income tax			-		-
Decommissioning liability	13		1,976		1,744
			39,873		42,111
Total Liabilities		**$**	**51,855**	**$**	**59,623**
UNITHOLDERS' EQUITY					
Trust capital	14	$	281,404	$	276,526
Currency reserves			(69)		(5,017)
Accumulated earnings (loss)			5,770		1,690
Accumulated cash distributions			(55,848)		(48,020)
Total Unitholders' Equity		**$**	**231,257**	**$**	**225,179**
Total Liabilities and Unitholders' Equity		**$**	**283,112**	**$**	**284,802**

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

See Note 17 "Commitments" and Note 18 "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 March 31, 2013**		Three Months Ended March 31, 2012
Revenue		$	23,341	$	19,174
Royalties			(6,536)		(5,227)
			16,805		**13,947**
Operating expenses			2,383		2,828
Transportation expenses			565		391
Administrative expenses			1,421		1,361
Depreciation, depletion and amortization			7,249		5,078
Operating profit (loss)			**5,187**		**4,289**
Unit based compensation (recovery)	5		(1,208)		4,005
Finance expense	6		515		60
Risk management loss	3		1,788		1,186
Foreign exchange loss (gain) net			12		(10)
Earnings (loss) before taxes			**4,080**		**(952)**
Income tax expense (recovery)	7		-		-
Earnings (loss)		**$**	**4,080**	**$**	**(952)**
Other comprehensive income					
Items that may be reclassified subsequently to net income					
Foreign currency translation gain (loss)			4,948		(3,207)
Comprehensive income (loss)		**$**	**9,028**	**$**	**(4,159)**
Earnings (loss) per unit					
Basic and diluted	**8**	**$**	**0.14**	**$**	**(0.05)**

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

Eagle Energy Trust

Condensed Consolidated Statements of Changes in Unitholders' Equity

For the three months ended March 31, 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 (loss)		-	-	-	(952)	-	(952)	(952)
Foreign currency translation loss		-	-	(3,207)		-	-	(3,207)
Total comprehensive income		-	-	(3,207)	(952)	-	(952)	(4,159)
Issuance of trust capital		303	3,053	-	-	-	-	3,053
Trust unit issuance costs		-	(28)	-	-	-	-	(28)
Unitholder distributions		-	-	-	-	(5,023)	(5,023)	(5,023)
		303	3,025	-	-	(5,023)	(5,023)	(1,998)
Balance at March 31, 2012		**18,847**	**171,200**	**(3,925)**	**(5,379)**	**(26,277)**	**(31,606)**	**$ 135,699**
Balance at December 31, 2012		**29,269**	**276,526**	**(5,017)**	**1,690**	**(48,020)**	**(46,330)**	**$ 225,179**
Earnings		-	-	-	4,080	-	4,080	4,080
Foreign currency translation loss		-	-	4,948	-	-	-	4,948
Total comprehensive income		-	-	4,948	4,080	-	4,080	9,028
Issuance of trust capital	14	691	4,878	-	-	-	-	4,878
Trust unit issuance costs	14	-	-	-	-	-	-	-
Unitholder distributions	11	-	-	-	-	(7,828)	(7,828)	(7,828)
		691	4,878	-	-	(7,828)	(7,828)	(2,950)
Balance at March 31, 2013		**29,960**	**281,404**	**(69)**	**5,770**	**(55,848)**	**(50,078)**	**$ 231,257**

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

Eagle Energy Trust

Condensed Consolidated Cash Flow Statements

For the three months ended March 31, 2013 and March 31, 2012
(Thousands of Canadian dollars) (unaudited)

	Note	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Cash flows from operating activities			
Net cash generated by operating activities	15	**$ 8,503**	**$ 7,511**
Cash flows from investing activities			
Additions to exploration and evaluation		(19)	(83)
Additions to oil and gas properties		(4,100)	(2,475)
Additions to property, plant and equipment		(50)	(81)
Net cash used in investing activities		**$ (4,169)**	**$ (2,639)**
Cash flows from financing activities			
Long-term debt		(3,168)	-
Proceeds from issuance of units		4,878	3,053
Trust unit issue costs		-	(28)
Cash distributions to unitholders		(7,828)	(4,997)
Change in non-cash working capital		60	-
Deferred financing charges		-	(75)
Net cash used in financing activities		**$ (6,058)**	**$ (2,047)**
Net increase (decrease) in cash and cash equivalents		**(1,724)**	**2,825**
Effects of exchange rates on cash and cash equivalents		48	(165)
Cash at beginning of the period		4,007	7,495
Cash at end of the period		**$ 2,331**	**$ 10,155**

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

Eagle Energy Trust

Notes to Condensed Consolidated Financial Statements (unaudited)

For the three months ended March 31, 2013 and March 31, 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 and was settled with a 1/10 ounce gold coin and $200 from the initial unitholders. 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 issue in accordance with a resolution of the Board of Directors made on May 9, 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 annual audited IFRS Consolidated Financial Statements for the year ended December 31, 2012, except for 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 March 31, 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 costless collar contract for 300 bbls of oil per day with a May 2012 through April 2013 term at a floor of $US 95.00 per barrel and a ceiling of $US 108.25 per barrel.

2. A fixed contract to sell 200 bbls of oil per day with a January 2013 through April 2013 term and 500 bbls of oil per day with a May 2013 through December 2013 term, at a price of $US 103.45 per barrel.

3. 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.

4. A costless collar contract for 250 bbls of oil per day with an August 2012 through July 2013 term at a floor of $US 87.00 per barrel and a ceiling of $US 89.70 per barrel.

5. A costless collar contract for 250 bbls of oil per day with a September 2012 through August 2013 term at a floor of $US 90.00 and a ceiling of $US 91.60 per barrel.

6. A costless collar contract with a floor of $US 95.00 and a ceiling of $US 103.75 per barrel for the following volumes and terms: 300 bbls of oil per day with a January 2013 through July 2013 term, 500 bbls of oil per day with an August 1 to 31, 2013 term, and 800 bbls of oil per day with a September 2013 through December 2013 term.

7. 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.

8. 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.

9. 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.

Summary of Unrealized Risk Management Positions as at March 31, 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)	300	bbls/d	May-12	Apr-13	95.00	108.25		4		-
NYMEX (ii)	200	bbls/d	Jan-13	Apr-13	103.45	103.45		37		-
NYMEX (ii)	500	bbls/d	May-13	Dec-13	103.45	103.45		837		-
NYMEX (ii)	400	bbls/d	Jan-14	Dec-14	98.00	98.00		134		641
NYMEX (i)	250	bbls/d	Aug-12	Jul-13	87.00	89.70		(248)		-
NYMEX (i)	250	bbls/d	Sept-12	Aug-13	90.00	91.60		(236)		-
NYMEX (i)	300	bbls/d	Jan-13	Jul-13	95.00	103.75		37		-
NYMEX (i)	500	bbls/d	Aug-13	Aug-13	95.00	103.75		28		-
NYMEX (i)	800	bbls/d	Sep-13	Dec-13	95.00	103.75		276		-
NYMEX (iii)	500	bbls/d	Jan-14	Dec-14	100.00	100.00		(126)		(384)
NYMEX (ii)	300	bbls/d	Feb-13	Dec-13	93.25	93.25		(295)		
NYMEX (ii)	500	bbls/d	Jan-14	Dec-14	91.15	91.15		(144)		(151)
							$	**304**	**$**	**106**

(i) Represents costless collar transactions created by buying puts and selling calls (WTI reference prices).
(ii) Represents a fixed price financial swap transaction with a set forward sale price (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 March 31, 2013 is an asset of $410,000 (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 (Loss)

	Three Months Ended March 31, 2013			Three Months Ended March 31, 2012		
$000's	Realized loss (gain)	Unrealized loss (gain)	Total net loss (gain)	Realized loss (gain)	Unrealized loss (gain)	Total net loss (gain)
Net effect - risk management	**$ (24)**	**$ 1,812**	**$ 1,788**	$ 256	$ 930	$ 1,186

4. Operating segments

The operations of the Trust comprise 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

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

5. Unit-based payments

The following table reconciles unit-based compensation expense (recovery).

$ 000's	Note	**Three Months Ended March 31, 2013**	Three Months Ended March 31, 2012
Units issued on performance option surrender	5(a)	(29)	711
Restricted unit rights	5(b)	(119)	1,457
Unit options	5(c)	(994)	1,594
Unit rights	5(d)	(66)	243
Total unit-based compensation expense (recovery)		**$ (1,208)**	$ 4,005

The following table reconciles the unit-based payments liability.

$ 000's	Note	**March 31, 2013**	December 31, 2012
Units issued on performance option surrender	5(a)	560	589
Restricted unit rights	5(b)	1,358	1,588
Unit options	5(c)	2,988	3,982
Unit rights	5(d)	401	470
Total unit-based payments liability		**$ 5,307**	$ 6,629

Note (a)

Units issued upon surrender of performance options

At March 31, 2013, the fair value of the escrowed units was assumed to be equal to the March 31, 2013 closing price of $6.60 per unit (December 31, 2012 - $7.69 per unit, March 31, 2012 - $11.24 per unit). The following schedule shows the continuity of escrowed units issued upon surrender of performance options:

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

A forfeiture rate of 5% was used and this figure is an estimated expected rate.

Note (b)

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

For the three months ended March 31, 2013, $110,655 has been paid to the RUR holders (year ended December 31, 2012 - $1,086,248, three months ended March 31, 2012 – $nil).

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

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

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

	March 31, 2013	December 31, 2012	March 31, 2012
Fair value at the balance sheet date	$ 3.85	$ 4.48	$ 7.57
Volatility	32%	32%	35%
Life of RURs	7.8 years	8.0 years	8.8 years
Risk-free interest rate	1.91%	1.82%	2.13%

A forfeiture rate of 5% was used and this figure is an estimated expected rate. Given the limited 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:

	Three Months Ended March 31, 2013		Year Ended December 31, 2012		Three Months Ended March 31, 2012	
	Number of options	Weighted average exercise price	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	1,706,000	$ 8.62
Forfeited	(235,418)	5.47	(258,332)	8.32	-	-
Exercised	-	-	-	-	-	-
Granted	-	-	767,000	9.15	-	-
Outstanding at end of period	**1,979,250**	**$ 8.01**	2,214,668	$ 8.23	1,706,000	$ 8.62
Exercisable at end of period	**770,755**	**$ 7.61**	992,006	$ 7.85	437,500	$ 8.71

The range of exercise prices of the outstanding options is as follows at March 31, 2013:

	Weighted average exercise price	Weighted average contractual life (years)
$6.72 - $9.00	**$ 8.01**	**8.4**

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

	March 31, 2013	December 31, 2012	March 31, 2012
Fair value - at balance sheet date	$ 2.25	$ 2.93	$ 5.73
Unit trading price - closing	$ 6.60	$ 7.69	$ 11.24
Exercise price – weighted average	$ 8.01	$ 8.23	$ 8.62
Volatility	32%	32%	35%
Option life – weighted average	8.4 years	8.6 years	8.9 years
Distributions – none estimated, due to declining strike price feature	0%	0%	0%
Risk-free interest rate	1.91%	1.82%	2.13%

A forfeiture rate of 5% was used and this figure is an estimated expected rate. This estimate will be adjusted to the actual forfeiture 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 three months ended March 31, 2013, $3,590 has been paid to the UR holders (year ended December 31, 2012 - $nil, three months ended March 31, 2012 - $nil).

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

	Three Months Ended March 31,2013	Year Ended December 31, 2012	Three Months Ended March 31,2012
Balance, beginning of period	493,000	185,000	185,000
Issued	-	338,000	-
Forfeited	(40,000)	(30,000)	-
Balance, end of period	453,000	493,000	185,000
Number of unit rights vested	**68,337**	51,670	nil

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:

	March 31, 2013	December 31, 2012	March 31, 2012
Fair value at the balance sheet date	$ 1.92	$ 2.66	$ 6.15
Volatility	32%	32%	35%
Life of restricted URs	9.0 years	9.3 years	9.3 years
Risk-free interest rate	1.91%	1.82%	2.13%

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.

6. Finance expense

$ 000's	**Three Months Ended March 31, 2013**	Three Months Ended March 31, 2012
Interest expense on long-term debt	$ 439	$ -
Amortization of deferred financing costs	55	27
Standby and bank fees	11	29
Accretion of decommissioning provision	10	4
Finance expense	**$ 515**	$ 60

7. 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 March 31, 2013		Three Months Ended March 31, 2012
Earnings (loss) before taxation		$ 4,080		$ (952)
Expected tax rate		35%		35%
Expected income tax provision (recovery)		1,428		(333)
Decrease (Increase) resulting from:				
Non-deductible items – permanent differences				
Administrative expenses of the Trust	35%	195	35%	173
Unit-based compensation	35%	(423)	35%	1,402
Foreign exchange gain, net	35%	-	35%	(4)
Risk management loss	35%	-	35%	415
Changes in temporary differences for which no amounts are recognized	35%	213	35%	(733)
Items deductible at the subsidiary level				
Interest on internal debt of subsidiary	35%	(1,363)	35%	(930)
Other	35%	(50)	35%	10
Total income tax expense (recovery)	35%	**$ -**	35%	$ -

Deferred tax assets and liabilities:

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

$ 000's	March 31, 2013	December 31, 2012
Deferred tax liabilities		
Oil and gas properties in excess of tax value	$ 25,941	$ 17,989
Exploration and evaluation assets	-	-
	25,941	17,989
Less deferred tax assets:		
Non-capital losses – US based	(28,727)	(20,562)
Net deferred tax liability (asset) – before valuation allowance	(2,786)	(2,573)
Unrecognized deferred tax asset	2,786	2,573
Net deferred tax liability (asset)	**$ -**	$ -

8. Earnings (loss) per unit

$ 000's	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Earnings (loss) attributable to unitholders	$ 4,080	$ (952)
Weighted average number of units outstanding (basic and diluted)	29,545	18,673
Earnings (loss) per unit (basic and diluted)	**$ 0.14**	$ (0.05)

Calculation

Basic income per unit is calculated by dividing the income attributable to unitholders of the Trust by the weighted average number of units outstanding during the period. Diluted income 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. Excluded from the period ended March 31, 2013 number of units outstanding is the effect of the units issued upon surrender of performance options and units issuable under the unit option plan as their effect is anti-dilutive. Refer to notes 5(a) and 5(c) of "Unit based Payments".

9. 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	10,607	(5)	221	10,823
Transfers from exploration and evaluation	-	-	-	-
At March 31, 2013	**$ 314,782**	**$ 6,957**	**$ 1,936**	**$ 323,675**
Accumulated depreciation and impairment				
At December 31, 2012	$ (41,184)	$ (2,435)	$ -	$ (43,619)
Depreciation	(7,622)	(429)	-	(8,051)
At March 31, 2013	**$ (48,806)**	**$ (2,864)**	**$ -**	**$ (51,670)**
Net book value				
At December 31, 2012	$ 262,991	$ 4,527	$ 1,715	$ 269,233
Net change for the period	2,985	(434)	221	2,772
At March 31, 2013	**$ 265,976**	**$ 4,093**	**$ 1,936**	**$ 272,005**

The Trust does not capitalize general and administrative costs. Future development costs related to proved plus probable reserves of $113,412,693 (December 31, 2012 - $117,479,500) were included in the depletion calculation.

10. Property, plant and equipment

$ 000's	Furniture, fixtures, and equipment	Computer equipment	Vehicles and other	Total
Cost				
Opening Balance	$ 60	$ 299	$ 81	$ 440
Additions	24	30	4	58
At March 31, 2013	**$ 84**	**$ 329**	**$ 85**	**$ 498**
Accumulated Depreciation				
Opening Balance	$ (5)	$ (137)	$ (15)	$ (157)
Depreciation	(6)	(38)	(4)	(48)
At March 31, 2013	**$ (11)**	**$ (175)**	**$ (19)**	**$ (205)**
Net book value				
Opening Balance	**$** 55	$ 162	$ 66	$ 283
Net change	18	(8)	-	10
At March 31, 2013	**$ 73**	**$ 154**	**$ 66**	**$ 293**

11. Distributions payable

$ 000's	**March 31, 2013**	December 31, 2012
Beginning balance	$ 2,570	$ 1,656
Distributions declared	7,828	26,816
Less distributions paid	(7,767)	(25,902)
Outstanding distributions declared and payable	**$ 2,631**	$ 2,570

Distributions are declared and paid monthly. The outstanding balance at March 31, 2013 represents the distribution declared March 15, 2013 and paid April 23, 2013. The outstanding balance at December 31, 2012 represents the distributions declared December 17, 2012 and paid January 23, 2013.

12. Long-term debt

As at March 31, 2013, $CA 37.9 million has been drawn under the $US 48.5 million credit facility by way of LIBOR borrowing and base rate loans. For the three month period ended March 31, 2013 the interest rate was 4.6%.

At March 31, 2013, there were no covenant violations.

13. Decommissioning liability

$000's	**Three Months Ended March 31, 2013**	Year Ended December 31, 2012
Beginning Balance	$ 1,744	$ 502
Acquisition	-	709
Additions	-	666
Changes in estimates	184	(158)
Accretion (unwinding of discount)	10	25
Effects of exchange rate	38	-
Ending Balance	**$ 1,976**	$ 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 2013 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 March 31, 2013 (March 31, 2012 – 3%).

14. Trust capital

Trust units outstanding

	Three Months Ended March 31, 2013			Year Ended 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	691		4,878	1,763		16,435
Issuance of Trust units(i)	-		-	8,680		95,480
Units released from escrow	-		-	282		2,779
Trust Unit issuance costs	-		-	-		(6,343)
Ending balance	**29,960**	**$**	**281,404**	29,269	$	276,526

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

For the three months ended March 31, 2013, the Trust incurred $nil (December 31, 2012 - $261,368) of unit issuance costs.

Trust units issued, but not classified as outstanding

Refer to note 5 "Unit-based payments". The 105,417 units issued to certain directors, management and a consultant on the surrender of previously granted performance options have been excluded from units outstanding as a result of IFRS principles which exclude units due to the performance conditions that have to be met in order for the units to be released from escrow.

15. Cash generated from operations

$ 000's		**Three Months Ended March 31, 2013**		Three Months Ended March 31, 2012
Income (loss) for the period	$	4,080	$	(952)
Adjustments for:				
Depreciation, depletion and amortization		7,249		5,101
Unit-based compensation – non-cash portion		(1,322)		4,005
Unrealized risk management loss		1,812		930
Finance expense		65		34
		11,884		9,118
Changes in working capital:				
Trade and other receivables		1,006		(616)
Prepaid expenses		21		102
Trade and other payables		(4,400)		(1,093)
		(3,373)		(1,607)
Cash (used in) generated from operations	**$**	**8,511**	$	7,511
Abandonment expenditures		8		-
Income taxes paid		-		-
Net cash generated by operating activities	**$**	**8,503**	$	7,511

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

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Operating cash flow		
Unit-based compensation	$ (1,322)	$ 4,005
Distributions payable – declared not yet paid	2,631	1,683
Unrealized risk management loss	1,812	930
Investment activities		
Depreciation, depletion and amortization	7,249	5,101
Provision for decommissioning costs	222	15
Accretion of decommissioning provision	10	4
Financing activities		
Finance expense-amortization of deferred financing costs	55	29
Distributions accrued – declared not yet paid	(2,631)	(1,683)

16. 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, Vice-President Operations, Vice-President Business Development, Vice-President Finance, US Controller, 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.

Head office lease in Calgary, Alberta

Up to May 1, 2013, the Trust sub-leased office space along with furniture and equipment from a company of which a director of the Administrator of the Trust is the President and Chief Operating Officer. The terms of the agreement are recorded at the exchange amount. The monthly rent rate is $9,250 per month. Refer to note 17 "Commitments" regarding operating lease commitments. On April 1, 2013, the Trust served its 30 day notice of termination of the sub-lease agreement.

No amounts were owing to this related party as at March 31, 2013 and December 31, 2012. For the three months ended March 31, 2013, administrative expenses included $27,750 (March 31, 2012 - $25,500) for amounts billed from this related party.

17. Commitments

Operating lease commitment – head office lease in Calgary, Alberta

The monthly rent of the Trust's sub-lease agreement for its former office space was $9,250. On April 1, 2013, the Trust served its 30 day notice of termination of the sub-lease agreement.

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 $2.0 million and include an available leasehold improvements allowance up to $0.3 million, with 58 months and approximately $2.0 million remaining at March 31, 2013.

Operating lease commitment – office lease in Houston, Texas

The 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 57 months and approximately $US 1.24 million remaining at March 31, 2013. In $CA the remaining future minimum lease payments approximate $1.3 million translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.016.

Operating lease commitment – office lease in Luling, Texas

The 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 with a monthly rate of $US 1,650. Future minimum payments during the term of the sublease and the extension approximate $US 80,000, with 29 months and approximately with $US 48,000 remaining at March 31, 2013. In $CA, the remaining future minimum lease payments approximate $49,000 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.016.

Operating lease commitment – office lease in Midland, Texas

The 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 42 months and approximately $US 177,000 remaining at March 31, 2013. In $CA the remaining future minimum lease payments approximate $180,000 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 1.016.

Drilling rig commitment – 4 wells

The Trust, through its operations in the Midland area entered into a four well drilling rig commitment with an option to drill two additional wells effective January 17, 2013. Future minimum payments are estimated to be approximately $US 0.9 million, which is 100% of the commitment. The net commitment to the Trust, based upon its approximate 92.5% interest is $US 0.8 million. In $CA the net future commitment approximates $0.8 million translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 1.016.

18. Subsequent events

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 located near Midland, Texas for cash consideration of $US 8,544,500, subject to closing adjustments and effective January 1, 2013 (the “Acquisition”). 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.

Increase in Eagle Energy Acquisitions LP borrowing base

Effective April 22, 2013, the borrowing base under the credit facility was increased to $US 61 million. All other terms and conditions, as described in note 12, remain unchanged. In addition, the credit facility has been syndicated to include a second Canadian chartered bank.

Drilling rig commitment – 6 wells

The Trust, through its operations in the Salt Flat area entered into a six well drilling rig commitment effective April 24, 2013. Future minimum payments are estimated to be approximately $US 0.7 million. In $CA, the net future commitment approximates $0.7 million translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 1.016.