EAGLE ENERGY™
TRUST

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("**MD&A**") of financial condition and results of operations for Eagle Energy Trust (the "**Trust**"), dated May 13, 2011, should be read in conjunction with the Trust's unaudited interim consolidated financial statements and accompanying notes for the period ended March 31, 2011 and the Trust's audited consolidated financial statements and accompanying notes for the year ended December 31, 2010 and related management's discussion and analysis and the Trust's Annual Information Form, all of which are filed on SEDAR at www.sedar.com and are available on the Trust's website at www.eagleenergytrust.com.

The Trust's unaudited interim consolidated 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 unaudited interim consolidated 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 at the end of this MD&A.

Non-IFRS Financial Measures

This MD&A makes 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. See the "Non-IFRS Financial Measures" section of this MD&A for a reconciliation of funds flow from operations and field netback to loss for the period, the most directly comparable measure in the Trust's unaudited interim consolidated financial statements. Other financial data has been prepared in accordance with IFRS.

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 conventional onshore oil and natural gas 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, oil and natural gas focused, distribution producing investment, with favourable tax treatment relative to taxable Canadian corporations.

The Trust was formed July 20, 2010. 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% working interest in the Salt Flat field, a light oil property located in south central Texas, for $127.1 million. Consideration consisted of cash and 2,000,000 trust units valued at $20 million.

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.

Comparative Financial Information

Since the Trust was formed July 20, 2010 and closed its initial public offering and commenced operations with the acquisition of the Salt Flat field on November 24, 2010, no comparative financial information is available for presentation in the financial statements and this MD&A.

Highlights for the three months ended March 31, 2011

- No bank debt, an expanded $US 15 million credit facility available and working capital of $16.2 million, which provides the Trust with substantial financial resources to execute its business plan.

- Funds flow from operations of $5.2 million ($45.47 per bbl or $0.29 per unit).

- Average working interest sales volumes of 1,269 bbls per day of light oil, a 75% increase from December 2010, the initial period of operations. Current working interest sales volumes estimated at 1,360 bbls per day.

- 7 (5.6 net) oil wells drilled during the quarter in the Salt Flat Field, with a 100% success rate.

- One (0.80 net) oil well, a 2010 drill, brought on-stream in early January 2011. First quarter volumes also benefitted from three (2.4 net) oil wells that were brought on-stream in mid to late December 2010.

- Two (1.6 net) oil wells, both 2010 drills, brought on-stream one week after quarter end. One (0.80 net) well, also a 2010 drill, will be on-stream in the near future. This leaves an inventory of 12 (9.6 net) wells that are expected to be tied in and on production early in the third quarter of 2011.

- First quarter unitholder distributions of $0.26 per unit ($0.0875 per unit per month).

- Implementation of a regular distribution reinvestment program and a Premium Distribution™ program, beginning with the March distribution payment, which was paid on April 21, 2011.

Summary of Quarterly Results

($ except for bbls per day amount)	Q1/2011	Q4/2010[1]
Production – bbls per day (100% light oil)	**1,269**	726
Revenue, net of royalties	**7,135,417**	1,366,494
per bbl	**62.49**	60.74
Funds flow from operations	**5,192,332**	(288,076)[2]
per bbl	**45.47**	(12.81)
per unit – basic & diluted	**0.29**	(0.07)
Loss for the period	**(1,911,011)**	(3,213,531)[2]
per unit – basic & diluted	**(0.11)**	(0.81)
Cash distributions declared	**4,728,040**	1,916,432
per issued unit	**0.2625**	0.1064
Current assets	**27,919,736**	33,102,821
Current liabilities	**11,712,277**	9,061,984
Total assets	**154,137,632**	159,868,227
Total non-current liabilities	**2,893,127**	724,833
Unitholders' equity	**139,532,228**	150,081,410
Units outstanding for accounting purposes	17,624,081[3]	17,624,081[3]
Units issued	18,011,581	18,011,581

Notes:

(1) From its formation on July 20, 2010 until the closing of its initial public offering on November 24, 2010, the Trust did not have any active operations.

(2) These results are not an indicative trend of future performance due to the short inclusion period of the Salt Flat field operations, non-recurring administrative costs related to the start-up of the Trust, one-time transaction expenses incurred for the acquisition of the Salt Flat field and initial expenses related to unit based compensation and debt conversion.

(3) Units outstanding for accounting purposes excludes 387,500 units issued due to the performance conditions that have to be met to enable such units to be released from escrow.

Results of Operations

Revenue

	Three months ended March 31, 2011 $ / bbl
Benchmark WTI ($US)	93.92
Oil revenue before royalties	86.39
Royalties	(23.90)
Revenue	**62.49**

Working interest sales volumes for the three months ended March 31, 2011 averaged 1,269 bbls per day (100% light oil), a 75% increase from December 2010 levels (the initial period of operations). First quarter volumes benefitted from four (3.2 net) oil wells that were brought on-stream in mid to late December 2010 and early January 2011.

Since the Salt Flat field is slightly sour, there is a differential between the West Texas Intermediate ("WTI") benchmark price and the realized sales price. The Trust's wholly-owned subsidiary in the US has also secured transportation and marketing agreements to ensure that volumes will continue to be marketed at attractive differentials to the WTI posted price.

The overall royalty rate was consistent with the prior period at 28%.

Cost of sales

	Three months ended March 31, 2011 $ / bbl
Transportation	1.97
Other operating costs	9.51
	11.49
Depreciation, depletion and amortization	25.30
Cost of sales	**36.79**

The largest component of operating expenses in the Salt Flat field are electricity, chemicals and field labor. By implementing its previously announced 2011 capital budget and bringing additional wells on-stream to realize efficiencies commensurate with the commercial development of the Salt Flat field, the Trust expects to achieve annual 2011 operating costs, including transportation, ranging from $10.00 to $11.50 per barrel.

The depletion, depreciation and amortization provision for the three months ended March 31, 2011 was based on proved plus probable reserves, including the future development costs associated with those reserves, in the 2010 year end reserve report prepared by the Trust's external evaluation engineers.

Field netback

	Three months ended March 31, 2011	
	$	**$ / bbl**
Oil revenue before royalties	9,864,775	86.39
Royalties	(2,729,358)	(23.90)
Transportation	(225,173)	(1.97)
Other operating costs	(1,086,280)	(9.51)
Field netback	**5,823,964**	**51.00**
Working interest sales volumes (bbls per day)		**1,269**

During the quarter, benchmark WTI averaged $US 93.92 per barrel and the Trust realized a field netback of $51.00 per barrel. For 2011 internal budgeting purposes, a WTI benchmark of $US 88.00 per barrel was used.

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

Realized and unrealized risk management loss

To mitigate the effects of fluctuating prices on a portion of its production, the Trust entered into the following contracts during the quarter: (i) a costless collar contract for 200 bbls of oil per day with a February 2011 through January 2012 term at a floor of $US 85.00 per barrel and a ceiling of $US 100.00 per barrel; (ii) a costless collar contract for 200 bbls of oil per day with a May 2011 through April 2012 term at a floor of $US 88.00 per barrel and a ceiling of $US 107.55 per barrel; and (iii) a fixed contract to sell 100 bbls of oil per day with a May 2011 through April 2012 term at a price of $US 101.00 per barrel.

For the three months ended March 31, 2011, the Trust realized an $18,225 risk management loss relating to these contracts in its income statement. Although the Trust currently has no intention of unwinding the contracts that are in place, it was required to calculate, using a mark-to-market valuation, the fair value of the remaining term of the contracts. As a result, a $1,414,002 unrealized risk management loss was also recorded.

Administrative expenses

Total administrative expenses for the quarter were $1,126,872. Approximately 40% was attributable to salaries and wages and 25% was related in aggregate to professional service costs, audit, tax and directors' fees. On a go-forward basis, per barrel administrative costs are expected to trend lower due to increased production.

Unit based compensation

Unit based compensation expense of $2,774,856 was recorded as an additional liability and related to changes in (i) the estimated fair value of escrowed units and restricted unit rights that were previously issued upon surrender of performance options ($1,458,983) and (ii) the estimated fair value of options granted under the option plan ($1,315,873).

None of the unit based compensation awards have vested. The dollar amount of unit based compensation expense does not represent cash paid by the Trust. The actual value realized by holders of the awards will depend on the price the escrowed units are eventually sold for, the accumulated distributions actually paid by the Trust, the actual year over year price appreciation of the units and the actual price of the units at the time the options are exercised.

The Trust is, however, required to re-determine the fair value of the liability relating to the escrowed units, restricted unit rights and options at the end of each reporting period and record any changes in fair value through the income statement. 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 that are derived using the Black-Scholes valuation model and cause corresponding swings in the amount recorded in the income statement. The increase in the liability and associated expense from December 31, 2010 to March 31, 2011 was due to an increase in the unit price from a $10.00 per unit initial public offering price to a closing price of $11.89 per unit at March 31, 2011.

Tax horizon

The tax horizon as determined from a full cycle corporate model incorporating cash flows from the year end external engineering 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 Salt Flat interest for several years. Management expects to extend this period through continued capital investments and additional acquisitions in the U.S. as we execute our 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.

Liquidity and Capital Resources

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

Management's objective is to maintain an external debt to cash flow ratio of approximately 1.0 times and not to exceed 1.5 times.

The Trust believes that its expected funds flow from operations, undrawn credit facility and working capital surplus will be sufficient to fund its planned capital investment program, enable it to meet all current and expected financial requirements and maintain unitholder distributions. 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 is discretionary.

Funds flow from operations

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

	Three months ended March 31, 20110	
	$	**$/bbl**
Field netback	5,823,964	51.00
Administrative expenses [(1)]	(1,126,872)	(9.87)
Risk management loss - realized	(18,225)	(0.16)
Finance expense and other	(4,881)	(0.04)
Realized foreign exchange gain [(2)]	518,346	4.54
Funds flow from operations	**5,192,332**	**$45.47**

Notes:
(1) On a go-forward basis, per barrel administrative costs are expected to trend lower due to increased production.
(2) 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, 2011, the Trust had no external debt and had available a $US 8.0 million credit facility, indirectly through its U.S. subsidiary, with a U.S. affiliate of a Canadian chartered bank.

Effective May 12, 2011, the credit facility was expanded to $US 15.0 million. All other terms and conditions remain unchanged.

Working capital

At March 31, 2011, the Trust had a working capital surplus, excluding the $1.4 million current portion of the unrealized risk management liability, of $17.6 million and no amounts drawn on its

$US 8.0 million bank credit facility. The credit facility was subsequently expanded to $US 15.0 million.

Unitholder's Equity

No additional funds were raised or units issued during the quarter. Management may seek to issue additional units in the future to provide sufficient capital to fund growth, including acquisition opportunities.

As a result of implementing its Premium Distribution™ and Distribution Reinvestment Plan, the Trust will receive monthly proceeds resulting from the issuance of units from treasury to those unitholders who have opted to participate in the Plan. For the initial month of this Plan, 89,555 units were issued on April 21, 2011 for proceeds of $976,105 (or $10.90 per unit).

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 2010, January 2011 and February 2011 record dates) totaled $5,068,459.

As at March 31, 2011, the Trust had issued 18,011,581 units. For purposes of the March 31, 2011 unaudited interim consolidated financial statements, 17,624,081 units were shown as outstanding. The 387,500 difference relates to units that were previously issued on the surrender of performance options but were excluded from financial statement figures because IFRS principles exclude the units that require a performance condition to be met before they can be released from escrow. Distributions are paid on the units while they are in escrow.

As at the date of this MD&A, 18,101,136 units are issued and 1,342,500 options are outstanding.

Capital expenditures

Capital spending during the first quarter of 2011 was as follows:

	Three months ended March 31, 2011 $
Exploration and evaluation - land	149,815
Acquisition of the Salt Flat field interest - adjustment	(119,084)
Intangible drilling and completions	4,819,917
Well equipment and facilities	633,466
Other	27,517
	5,511,631

During the quarter, 7 (5.6 net) oil wells were drilled in the Salt Flat Field, with a 100% success rate. In addition, one (0.80 net) oil well, a 2010 drill, was brought on-stream in early January 2011 and capital was invested in two additional tie-ins which were brought on-stream in early April. Related infrastructure investment, including oil batteries and construction of a power trunk line to the southern half of the Salt Flat Field continued.

Commitments

The Trust has committed to future payments as follows:

	Total $	Less than 1 year $	1 – 3 years $	After 3 years
Operating leases (1)(2)	351,725	155,018	196,707	--
Purchase obligation (3)	1,097,587	1,097,587	--	--
Total contractual obligations	**$ 1,449,312**	**$ 1,252,605**	**$196,707**	**--**

Notes:

(1) This relates to an operating lease commitment for the head office in Calgary, Alberta. The term of the sub-lease agreement is six months from January 1, 2011 through June 30, 2011. Thereafter the agreement will automatically roll over on a monthly basis, unless either party serves a 30 day notice of termination. Therefore, the agreement is cancellable at the end of the term if notice is provided. Future minimum lease payments during the six month term of the sub-lease are $48,000, with $24,000 remaining as at March 31, 2011.

(2) This relates to an operating lease commitment for the office in Houston, Texas. The agreement was entered into on April 1, 2011, has an approximate 30 month term from April 7, 2011 through September 30, 2013. Future minimum lease payments during the term of the sub-lease approximate $US 338,000. This commitment has been translated at the exchange rate in effect at the balance sheet date of 0.9696 CAD = 1.00 USD.

(3) This relates to a six month drilling rig commitment secured to execute the budgeted 2011 capital drilling program. The Trust, through its joint venture relationship in the Salt Flat field, entered into a six month drilling rig commitment agreement effective February 3, 2011. The agreement is then cancellable with a 30 day written notice of termination. The daily rig rate is $US 11,500, resulting in future minimum payments during the six month (180 days) term of the agreement of $US 2,070,000, which is 100% of the commitment. The net commitment to the Trust based upon its approximately 80% interest equates to $US 1,656,000, with $1,132,000 remaining as at March 31, 2011. This commitment has been translated at the exchange rate in effect at the balance sheet date of 0.9696 CAD = 1.00 USD.

Transactions with Related Parties

Intercompany transactions

There are certain intercompany transactions among the subsidiaries comprising the audited consolidated financials of Eagle Energy Trust. These transactions have been eliminated upon consolidation.

Head office lease, Calgary, Alberta

The Trust sub-leases 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 monthly rent rate is $8,000 and the terms of the agreement are recorded at the exchange amount. Refer to the “Commitments” section of this MD&A. No amounts were owing to this related party as at March 31, 2011. For the three months ended March 31, 2011, administrative expenses included $24,000 for amounts billed from this related party.

Critical Accounting Estimates

The Trust makes estimates and assumptions concerning the future. The resulting accounting estimates will, by definition, seldom equal the related actual results. Such estimates and assumptions are continually evaluated by Management and are based on historical experience and other factors, including expectations of future events that Management believes to be reasonable under the circumstances. The Trust was formed on July 20, 2010 and there have been no changes made to critical accounting estimates since its formation.

The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below.

Estimation of oil and gas reserves

Oil and gas reserves are the estimated quantities of oil and gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of oil and gas reserves are inherently imprecise, require the application of judgment and are subject to future revision. Accordingly, financial and accounting measures (such as the impairment calculation, depreciation, depletion and amortization charges, and decommissioning provisions) that are based on reserves are also subject to change.

Capitalized exploration and evaluation expenditures

In making decisions about whether to continue to capitalize exploration and evaluation expenditures, it is necessary to make judgments about the probable commercial reserves and the level of activities that constitute on-going evaluation determination. If there is a change in any judgment in a subsequent period, then the related capitalized exploration and evaluation expenditure would be expensed in that period, resulting in a charge to income.

Decommissioning provision

Estimates of the amounts of provision for decommissioning recognized are based on current legal and constructive requirements, technology and price levels. As actual outflows may be different from estimates due to changes in laws, regulations, technology, prices and conditions, and can take place in the future, the carrying amounts of provisions are regularly reviewed and adjusted to take account of such changes. Because the accounting standard is not clear as to the choice of risk-free or risk-adjusted discount rate, the Trust interpreted the accounting standard to use the risk-free discount rate for calculating the present value of the decommissioning obligation.

Impairment indicators

The recoverable amounts of cash-generating units and individual assets have been determined based on the higher of value-in-use calculations and fair values less costs to sell. These calculations require the use of estimates and assumptions. It is reasonably possible that the commodity price assumption may change, which may impact the estimated life of the field which may, in turn, require a material adjustment to the carrying value of assets. The Trust monitors internal and external indicators of impairment relating to its tangible and intangible assets.

Income taxes

The Trust recognizes the net future tax benefit related to deferred income tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of deferred income tax assets requires the Trust to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Trust to realize the net deferred tax assets recorded at the balance sheet date could be impacted.

Additionally, future changes in tax laws in the jurisdiction in which the Trust operates could limit the ability of the Trust to obtain tax deductions in future periods.

Derivative financial instruments

As described in the Risk Management section of this MD&A, derivative financial instruments are used by the Trust to manage its exposure to market risks relating to commodity prices. The Trust's policy is not to use derivative financial instruments for speculative purposes. Derivative financial instruments that do not qualify, or are not designated, as hedges for accounting are recorded at fair value. Instruments are recorded in the balance sheet as either an asset or a liability with changes in fair value recognized in the income statement. The estimate of fair value of all derivative instruments is based on quoted market prices, or in their absence, third-party market indications and forecasts. The estimated fair value of financial assets and liabilities is subject to measurement uncertainty.

Classification of trust units as equity

Trust units issued by income trusts give the holder the right to put the units back to the issuer in exchange for cash. IAS 32 "Financial Instruments: Presentation" establishes the general principle that an instrument which gives the holder the right to put the instrument back to the issuer for cash should be classified as a financial liability, unless such instrument has all of the features and meets the conditions of the IAS 32 "puttable instrument exemption". If these "puttable instrument exemption" criteria are met, the instrument is classified as equity. The Trust has examined the terms and conditions of its Trust Indenture and classifies its outstanding trust units as equity because the trust units meet the "puttable instrument exemption" criteria as there is no contractual obligation to distribute cash.

Contingencies

By their nature, contingencies will only be resolved when one or more future events occur or fail to occur. The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events.

Accounting standards and interpretations issued but not yet adopted:

At the date this MD&A, the following standards and interpretations, which have not been applied in the consolidated financial statements, were issued but not yet in effect:

- IAS 24 (revised) — "Related Party Disclosures"
- Amendment to IFRIC 14 — "Prepayments of a minimum funding requirement"
- IFRS 9 — "Financial Instruments"
- Improvements to IFRSs (2010) — IFRS 1, IFRS 3, IFRS 7, IAS 1, IAS 27, IAS 34, and IFRIC 13.

The assessment of the impact of the above standards and interpretations on the Trust's accounting policies and on the presentation of the financial statements is at an early stage, but there is not expected to be a significant impact on the financial statements of the Trust in future periods. 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.

Risk Management

For a more detailed description of the risks and uncertainties faced by the Trust, refer to the Trust's Annual Information Form. The Trust's activities expose it to a variety of financial risks that arise as a result of its exploitation, development, production, and financing activities such as:

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

Credit risk is the risk of financial loss to the Trust if a customer or counterparty to a financial instrument fails to meet its contractual obligations and arises principally from the Trust's receivables from its oil marketer. Receivables from the Trust's oil marketer are normally collected in the month following production. The Trust's policy to mitigate credit risk associated with these balances is to establish marketing relationships with reputable purchasers with good credit and, over time, to spread this risk among as many different marketers as is reasonably feasible.

Liquidity risk is the risk that the Trust will not be able to meet its financial obligations as they fall due. At March 31, 2011, the Trust had a working capital surplus, excluding the $1.4 million current portion of the unrealized risk management liability, of $17.6 million and no amounts drawn on its $US 8.0 million bank credit facility. The credit facility was subsequently expanded to $US 15 million. The approach to managing liquidity is to ensure, as far as possible, that the Trust will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Trust's reputation. To better manage its liquidity risk, the Trust prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Trust utilizes authorizations for expenditures ("AFEs") on both operated and non-operated projects to manage capital expenditures. The Trust attempts to match its payment cycle with the collection of its oil and natural gas revenue each month.

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 of the Trust. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing returns.

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by various factors, including the exchange rates between the Canadian and United States dollar, and national and international economic events which dictate the levels of supply and demand. The Trust may enter 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. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors. It is the policy of the Trust to not hedge more than 50% of its near-term net production. For the period ended, and as of March 31, 2011, the Trust has entered into three contracts to mitigate the effect of commodity price fluctuations in the coming 12 months. Refer to the "Realized and unrealized risk management loss" section of this MD&A.

Foreign exchange risk is the risk that future cash flows will fluctuate as a result of changes in market foreign exchange rates. The Trust's operating cash flows are generated in US dollars and distributions are declared in Canadian dollars. As a consequence, there is an element of foreign exchange risk to the Trust. The Trust's treasury management function is responsible for managing funding requirements and investments, which include banking and cash flow management. Prices for oil have traditionally been determined by global markets and denominated in US dollars. Generally, an increase in the value of the $CA as compared to the $US will reduce the prices received by the Trust for its petroleum and natural gas sales, but will also reduce the operating expenses associated with those sales as well as reduce the price paid by the subsidiary of the Trust for additional asset acquisitions.

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Trust may be exposed to interest rate risk at both fixed and variable rates as it borrows funds. There have been no draws against the credit facility and no amounts were outstanding under the credit facility as of March 31, 2011. The Trust therefore had no interest rate risk, and as a result, did not hedge against any interest rate exposures.

Outlook

This section includes forward looking information, including information in respect of the Trust's anticipated drilling plans, tie-in of wells, investment in infrastructure, expected average production and operating costs, and expected results of its business plan for 2011. Refer to the Note about Forward Looking Statements at the end of this MD&A.

As outlined in a January 20, 2011 press release by the Trust, the Board of Directors approved a 2011 capital budget of $US 22.9 million. The Trust, indirectly through its subsidiaries, intends to invest these funds in drilling 21 horizontal production wells, five salt water disposal wells, as well as related infrastructure projects that are expected to reduce operating costs and increase operational efficiencies. As a result, the Trust expects to achieve 2011 working interest average production ranging from 1,900 to 2,100 bbls per day of light oil, and operating costs, including transportation, ranging from $10.00 to $11.50 per barrel.

Currently the twelfth well of the 2011 capital program is being drilled. To date, three wells (all 2010 drills) have been tied in and one additional well (also a 2010 drill) will be on-stream in the near future. This leaves an inventory of 12 wells that are expected to be tied in and on production early in the third quarter of 2011. Salt water disposal wells are needed in order to bring production on-stream, and increased drilling activity in south central Texas has resulted in Eagle experiencing delays in obtaining permits to drill salt water disposal wells. Permits to drill an oil well typically take one to two days to receive, while permits to drill a salt water disposal well can take up to 90 days.

The capital budget excludes additional asset acquisitions, which will be separately considered and evaluated as circumstances arise. The amount and allocation of the Trust's 2011 capital budget is dependent upon results achieved and is subject to review by Management and the Board of Directors on an ongoing basis throughout the year.

The Trust will continue to execute, indirectly through its subsidiaries, its integrated business plan to acquire and develop high quality, long life oil and gas properties in the United States.

Non-IFRS Financial Measures

The following table reconciles the non-IFRS financial measures "funds flow from operations" and "field netback" to "loss for the period", the most directly comparable measure in the Trust's consolidated financial statements:

	Three months ended March 31, 2011 $
Loss for the period	**$(1,911,011)**
Add back items not involving cash:	
Unit based compensation	2,774,856
Unrealized risk management loss	1,414,002
Depletion, amortization and accretion	2,894,739
Finance expense	19,746
Funds flow from operations	**$5,192,332**
Add back (deduct) items not directly related to field operations:	
Realized foreign exchange gain	(518,346)
Finance expense (cash portion) and other	4,881
Risk management loss - realized	18,225
Administrative expenses	1,126,872
Field netback	**$5,823,964**

Limitations on Scope of Design of Disclosure Controls and Internal Controls over Financial Reporting

The Trust closed the acquisition of the Salt Flat field on November 24, 2010 and there has been insufficient time to design or evaluate controls, policies and procedures since acquiring this business. Accordingly, the Trust is limiting its design of disclosure controls and procedures and internal controls over financial reporting to exclude controls, policies and procedures relating to the acquisition of the Salt Flat field. Throughout this MD&A, however, full financial information related to the acquired business has been disclosed and been incorporated into the Trust's audited consolidated financial statements.

Note about Forward-Looking Statements

This MD&A contains forward-looking statements that describe what management believes might occur in the future in respect of the Trust and its subsidiaries. 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. No assurance can be given that management's beliefs or expectations will prove to be correct and such forward-looking statements in this MD&A should not be unduly relied upon. These forward-looking statements are based on management's current expectations, estimates and projections as at the date of this MD&A and the Trust assumes no obligation to update or revise forward-looking statements to reflect new events or circumstances, except as required by law.

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

- the Trust's subsidiary's drilling plans and expectations regarding the tie-in of wells,
- the Trust's expectations to reduce operating costs and increase operational efficiencies through investment in infrastructure projects,
- the Trust's expectations regarding its 2011 company interest average production,
- the Trust's business plans and strategy,
- expectations regarding the marketing of volumes,

- expectations that per barrel administrative costs in the future will trend lower due to increased production in 2011,
- the taxability of the Trust and the status of the Trust as a mutual fund trust and not a SIFT trust,
- management's objective to maintain an external debt to cash flow ratio of approximately 1.0 times and not to exceed 1.5 times, and
- the Trust's expectations that its funds from operations, undrawn credit facility and working capital surplus will be sufficient to fund its planned capital investment program, enable it to meet all current and expected financial requirements and maintain unitholder distributions.

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

- future oil and gas prices,
- future currency exchange rates,
- 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",
- future production levels,
- future recoverability of reserves,
- future capital expenditures and the ability of the Trust to obtain financing on acceptable terms for its capital projects and future acquisitions,
- not including capital required to pursue future acquisitions in the forecasted capital expenditures,
- estimates of the anticipated production and product mix 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, and
- projected operating costs are based on historical information and anticipated increases in the cost of equipment and services.

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 included in the AIF:

- volatility of oil and gas prices,
- commodity supply and demand,
- fluctuations in currency and interest rates,
- inherent risks and changes in costs associated in the development of oil and gas properties,
- ultimate recoverability of reserves,
- timing, results and costs of drilling activities and pipeline construction,
- availability of financing and capital, and
- new regulations and legislation.

Additional risks and uncertainties affecting the Trust are contained in the Trust's December 31, 2010 AIF.

Actual performance and financial results in 2011 may differ materially from any projections of future performance or results expressed or implied by these forward-looking statements. The internal projections, expectations or beliefs are based on the Trust's 2011 capital budget, which is subject to change in light of ongoing results, prevailing economic circumstances, 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.

Eagle Energy Trust

Interim Consolidated Financial Statements
(unaudited)

For the Period Ended March 31, 2011

Eagle Energy Trust

Consolidated Balance Sheets (unaudited)
As at March 31, 2011
(in Canadian dollars)

	Note	March 31, 2011	December 31, 2010
ASSETS			
Current assets			
Cash and cash equivalents	16	23,632,821	31,731,118
Trade and other receivables	17	4,138,033	1,310,287
Prepaid expenses	18	148,882	61,416
		27,919,736	**33,102,821**
Non-current assets			
Exploration and evaluation	19	149,625	-
Oil and gas properties	20	125,818,862	126,519,338
Property, plant and equipment	21	55,704	34,739
Other intangible assets	22	193,705	211,329
		126,217,896	**126,765,406**
Total Assets		**154,137,632**	**159,868,227**
LIABILITIES			
Current liabilities			
Trade and other payables	23	8,780,925	7,145,552
Distributions payable	24	1,576,013	1,916,432
Risk management liability	5	1,355,339	-
		11,712,277	**9,061,984**
Non-current liabilities			
Other long term liabilities	23	2,564,559	507,453
Provision for liabilities and other charges	26	269,905	217,380
Risk management liability	5	58,663	-
		2,893,127	**724,833**
Total Liabilities		**14,605,404**	**9,786,817**
UNITHOLDERS' EQUITY			
Trust capital	27	159,462,397	159,577,493
Other reserves	11	(8,161,155)	(4,366,120)
Accumulated loss		(5,124,542)	(3,213,531)
Accumulated cash distributions	24	(6,644,472)	(1,916,432)
Total Unitholders' Equity		**139,532,228**	**150,081,410**
Total Liabilities and Unitholders' Equity		**154,137,632**	**159,868,227**

The notes are an integral part of these financial statements

Eagle Energy Trust

Consolidated Income Statement and Statement of Comprehensive Income (unaudited)
For the period ended March 31, 2011
(in Canadian dollars)

	Note	Three Months Ended March 31, 2011
Revenue	8	7,135,417
Cost of sales	9	4,200,514
Gross profit		2,934,903
Administrative expenses		1,126,872
Unit based compensation	10	2,774,856
Operating loss		**(966,825)**
Foreign exchange gain, net	11	518,346
Finance expense	12	(30,305)
Risk management loss	5	(1,432,227)
Loss before taxation		**(1,911,011)**
Income tax expense (reduction)	13	-
Loss for the period		**(1,911,011)**
Other comprehensive loss for the period		
Foreign currency translation loss	11	(3,795,035)
Total comprehensive loss for the period		**(5,706,046)**
Loss per unit during the period		
Basic	15	(0.11)
Diluted	15	(0.11)

The notes are an integral part of these financial statements

Eagle Energy Trust

Consolidated Statement of Changes in Unitholders' Equity (unaudited)
For the period ended March 31, 2011
(in Canadian dollars)

Three Months Ended March 31, 2011	Note	Number of trust units	Trust capital	Currency reserve	Accumulated loss	Accumulated cash distributions	**Total unitholders' equity**
Balance at December 31, 2010		**17,624,081**	**159,577,493**	**(4,366,120)**	**(3,213,531)**	**(1,916,432)**	**150,081,410**
Loss for the period		-	-	-	(1,911,011)	-	(1,911,011)
Foreign currency translation gain (loss)	11	-	-	(3,795,035)	-	-	(3,795,035)
Total comprehensive income (loss)		-	-	(3,795,035)	(1,911,011)	-	(5,706,046)
Trust unit issuance costs	27		(115,096)				(115,096)
Unitholder distributions	24					(4,728,040)	(4,728,040)
		-	(115,096)	-	-	(4,728,040)	(4,843,136)
Balance at March 31, 2011		**17,624,081**	**159,462,397**	**(8,161,155)**	**(5,124,542)**	**(6,644,472)**	**139,532,228**

The notes are an integral part of these financial statements

Eagle Energy Trust

Consolidated Cash Flow Statement (unaudited)
For the period ended March 31, 2011
(in Canadian dollars)

	Note	Three Months Ended March 31, 2011
Cash flows from operating activities		
Net cash generated by operating activities	28	**3,282,952**
Cash flows from investing activities		
Additions to exploration and evaluation		(149,625)
Additions to oil and gas properties		(5,334,489)
Additions to property, plant and equipment		(27,517)
Net cash used in investing activities		**(5,511,631)**
Cash flows from financing activities		
Trust unit issue costs		(115,096)
Cash distributions to unitholders		(5,068,459)
Net cash used in financing activities		**(5,183,555)**
Net decrease in cash and cash equivalents		**(7,412,234)**
Effects of exchange rates on cash and cash equivalents		(686,063)
Cash and cash equivalents at beginning of the period		31,731,118
Cash and cash equivalents at end of the period	16	**23,632,821**

The notes are an integral part of these financial statements

See note 28 for major non-cash transactions

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 oil and natural gas 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 consolidated financial statements, Eagle Energy Trust and its subsidiaries are referred to collectively as the "Trust" or "Eagle" for purposes of convenience. For a list of subsidiaries and a detailed description of the structure of the Trust, refer to "Subsidiaries and consolidated entities" note 6.

The strategy of the Trust is to acquire and exploit conventional, long-life hydrocarbon reserves in certain on-shore production basins 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 directly and indirectly owned subsidiaries of the Trust. Cash flow is paid to the Trust by way of interest payments, principal debt repayments or partnership distributions.

Operations officially commenced on November 24, 2010, concurrent with the closing of the Salt Flat Field acquisition (see "Acquisitions" note 7).

The address of the Trust is: 9th Floor, 639-5th Avenue SW, Calgary, AB T2P 0M9.

2.1 Basis of preparation

Basis of accounting

The consolidated financial statements were authorized for issue in accordance with a resolution of the Board of Directors made on May 12, 2011.

These interim "condensed" Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") and with International Accounting Standard ("IAS") 34, "Interim Financial Reporting," as issued by the International Accounting Standards Board ("IASB") and do not include all the necessary annual disclosures in accordance with IFRS. The most recent annual consolidated financial statements for the period ended December 31, 2010 were also prepared in accordance with IFRS.

The preparation of financial statements in conformity with IFRS requires Management to make estimates and assumptions that affect the reported amounts of revenues and expenses during the period, assets and liabilities, and the disclosure of contingent liabilities at the date of the financial statements. The key estimates and assumptions are set out in "Critical accounting estimates and judgments" note 3. Such estimates and assumptions are based on historical experience and various other factors that are believed to be reasonable in the circumstances and constitute Management's best judgment at the date of the financial statements. In the future, actual experience may deviate from these estimates and assumptions. This could affect future financial statements as the original estimates and assumptions are modified, as appropriate, in the year in which the circumstances change.

These financial statements have been prepared on the historical cost basis except for those items which are required to be stated at fair value. Historical cost is generally based on the fair value of the consideration given in exchange for the asset. The principal accounting policies adopted are set out below in "Significant accounting policies" note 2.3.

Basis of consolidation

The consolidated financial statements incorporate the financial statements of the Trust and entities controlled by the Trust (including its subsidiaries) up to the balance sheet date. Subsidiaries are all entities over which the Trust has the power to govern the financial and operating policies generally accompanying a security holding of more than one half of the voting rights. The existence and effect of potential voting rights that are currently exercisable or convertible are considered when assessing whether the Trust controls another entity. All subsidiaries of the Trust are directly or indirectly wholly-owned by the Trust.

A list of the subsidiaries has been included in "Subsidiaries and consolidated entities" note 6.

The activities of subsidiaries are included in the consolidated financial statements from the effective date that control commences until the date that control ceases. Intercompany balances and transactions and any unrealized income and expenses arising from intercompany transactions are eliminated in preparing the consolidated financial statements.

2.2 Adoption of new and revised standards

Accounting standards and interpretations issued but not yet adopted

At the date of authorization of these financial statements, the following standards and interpretations, which have not been applied in these financial statements, were issued but not yet in effect:

- IFRS 9 "Financial Instruments"

IFRS 9 is effective for periods beginning on or after January 13, 2013. The new standard is the first phase of the IASB's project to replace IAS 39, "Financial Instruments: Recognition and Measurement." IFRS 9 replaces the current multiple classification and measurement models for financial assets with a single model that has only two classification categories:

amortized cost and fair value, and provides additional guidance for financial liabilities. The adoption of this standard should not have a material impact on the Trust's consolidated financial statements.

Although it is anticipated the adoption of the above standard should not have a material impact, the exact impact will depend on the individual transaction concerned, with potentially different amounts being recognized in the consolidated financial statements than would have previously been the case.

2.3 Significant accounting policies

The accounting policies set out below have been applied consistently to all periods presented in these consolidated financial statements and have been applied consistently by the Trust and its subsidiaries.

Business combinations

The purchase method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in the income statement.

Jointly controlled operations and jointly controlled assets

Many of the Trust's oil and natural gas activities involve jointly controlled assets. The consolidated financial statements include the Trust's share of these jointly controlled assets and a proportionate share of the relevant revenue and related costs.

Foreign Currency

Items included in the financial statements of each of the Trust's entities are measured using the currency of the primary economic environment in which the entity operates (the "functional currency"). The consolidated financial statements are presented in "Canadian dollars" ("$CA"), which is the functional and presentation currency of the Trust.

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognized in the income statement. Non-monetary assets that are measured at fair value are translated using the exchange rate at the date that the fair value was determined. Translation differences on equities and similar non-monetary items measured at fair value are recognized in profit or loss, except for differences on available-for-sale non-monetary financial assets such as equity shares, which are included in the fair value reserve in equity unless the asset is a hedged item in a fair value hedge.

The results and financial position of all the Trust entities (none of which has the currency of a hyper-inflationary economy) that have a functional currency different from the presentation currency are translated into the presentation currency as follows:

(a) assets and liabilities for each balance sheet presented are translated at the closing rate at the date of that balance sheet;
(b) income and expenses for each income statement are translated at average exchange rates (unless the average is not a reasonable approximation of the cumulative effect of the rates prevailing on the transaction dates, in which case income and expenses are translated at the dates of the transactions);
(c) all items included in the statement of changes in equity, other than net profit or loss, for the year, are translated at historical exchange rates; and
(d) all resulting exchange differences are recognized as a separate component of equity.

On consolidation, exchange differences arising from the translation of the net investment in foreign entities are taken to unitholders' equity. When a foreign operation is sold or when control is lost, such exchange differences are recognized in the income statement as part of the gain or loss on sale.

Goodwill and fair value adjustments arising on the acquisition of a foreign entity are treated as assets and liabilities of the foreign entity and translated at the closing rate.

Financial instruments

Financial assets and financial liabilities are recognized in the balance sheet when the Trust becomes a party to the contractual provisions of the instrument. The effective interest rate method is a method of calculating the amortized cost of a financial asset or liability and allocating interest income or expense over the relevant period. The effective interest rate is the applicable discount rate for the estimated future cash receipts or payments over the expected life of the financial asset or liability.

Non-derivative financial instruments

Non-derivative financial instruments are recognized initially at fair value plus, for instruments not at fair value through profit or loss, any directly attributable transaction costs.

An instrument is classified at fair value through profit or loss if it is held for trading or is designated as such upon initial recognition. Financial instruments are designated at fair value through profit or loss if the Trust manages such investments and makes purchase and sale decisions based on their fair value in accordance with the Trust's risk management or investment strategy. Upon initial recognition attributable transaction costs are recognized in profit or loss when incurred. Financial instruments at fair value through profit or loss are measured at fair value and changes therein are recognized in profit or loss.

Subsequent to initial recognition non-derivative financial instruments are measured as described below.

(a) Financial assets
Financial assets are classified as loans and receivables. The classification depends on the purpose for which the financial assets were acquired. Management determines the classification of its financial assets at initial recognition.

(i) Loans and receivables
Cash and cash equivalents comprise cash on hand and current balances and deposits with banks or similar institutions which are readily convertible to cash and which are subject to insignificant risk of changes in value.

Trade receivables, loans and other receivables which are non-derivative financial assets that have fixed or determinable payments that are not quoted in an active market are classified as loans and receivables. They are included in current assets, except for those with maturities greater than 12 months after the balance sheet date, which are classified as non-current assets. The Trust's loans and receivables comprise cash and cash equivalents and trade and other receivables.

Loans and receivables are carried at their amortized cost using the effective interest rate method, net of any impairment. Interest income is recognized by applying the effective interest rate method, except for short-term receivables, where the recognition of interest would be immaterial.

(ii) Impairment of financial assets
Financial assets are assessed for impairment at each balance sheet date. Financial assets are impaired when there is objective evidence that the estimated future cash flows of the asset have been impacted. For loans and receivables, the amount of the impairment is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the original effective interest rate.

In the event of impairment, the carrying amount of the financial asset is reduced by the impairment loss, except for trade receivables where the carrying amount is reduced through the use of an allowance account. When a trade receivable is uncollectible, it is written off against the allowance account, and the amount of the loss is recognized in the income statement. Subsequent recoveries of amounts previously written off are credited against the income statement.

(b) Financial liabilities and equity
Financial liabilities and equity instruments are classified in accordance with IAS 32 "Financial Instruments: Presentation."

(i) Trade payables
Trade payables are recognized initially at fair value and subsequently measured at amortized cost using the effective interest rate method. Interest income is recognized by applying the effective interest rate, except for short-term payables when the recognition of interest would be immaterial.

(ii) Borrowings
Borrowings are recognized initially at fair value net of transaction costs incurred, including debt issuance costs in the form of cash payments. Borrowings are subsequently stated at amortized cost; any difference between the proceeds (net of transaction costs) and the redemption value is recognized over the term of the borrowings using the effective interest rate method and charged to the income statement as finance costs.

Borrowing costs incurred for the construction of any qualifying asset are capitalized during the period of time that is required to complete and prepare the asset for its intended use. To the extent that the Trust borrows funds generally and uses them for the purpose of obtaining a qualifying asset, the Trust determines the amount of borrowing costs eligible for capitalization by applying a capitalization rate to the expenditures on that asset. The capitalization rate is the weighted average of the borrowing costs applicable to the borrowings of the Trust that are outstanding during the period, other than borrowings made specifically for the purpose of obtaining a qualifying asset. The amount of borrowing costs that the Trust capitalizes during a period shall not exceed the amount of borrowing costs it incurred during that period.
For funds borrowed to obtain a qualifying asset, the borrowing costs eligible for capitalization are the actual borrowing costs incurred during the period less any investment income earned from the temporary investment of the borrowed funds.

All other borrowing costs are recognized in profit or loss using the effective interest method.

Where an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as derecognition of the original liability and recognition of a new liability, the difference between the carrying amounts of the original liability and the fair value of the new liability is recognized in the income statement.

Borrowings are classified as current liabilities unless the Trust has an unconditional right to defer settlement of the liability for at least 12 months after the balance sheet date.

(iii) Equity instruments
An equity instrument is any contract that evidences a residual interest in the assets of the Trust after deducting all of its liabilities. Equity instruments of the Trust are recorded at the proceeds received, net of incremental costs directly attributable to the issue of new trust units or options, which are shown as a deduction, net of tax, from the proceeds. Trust units are classified as equity.

(iv) Compound instruments
The exceptions in IAS 32 which allow an entity such as a trust to classify “puttable” instruments as equity do not extend to instruments such as warrants, options and convertible debt that entitle the holder to acquire “puttable” instruments for a fixed

price. Such instruments are classified as liabilities in their entirety under IAS 32.22A. Because of the "puttable" nature of trust units, there will always be an embedded derivative and the instrument shown as a liability.

Derivative financial instruments

The Trust enters into certain financial derivative contracts periodically in order to manage its exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The Trust does not designate its financial derivative contracts as effective accounting hedges and thus does not apply hedge accounting (even though the Trust considers all commodity contracts to be economic hedges). As a result, all financial derivative contracts are classified as fair value through profit or loss and are recorded on the balance sheet at fair value. Related transaction costs are recognized in profit or loss when incurred.

The Trust may enter into forward physical delivery sales contracts. The policy is to account for these forward physical delivery sales contracts, which are entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements, as executory contracts. As such, these contracts are not considered to be derivative financial instruments and will not be recorded at fair value on the balance sheet. Settlements on these physical sales contracts would be recognized in revenue.

Embedded derivatives are separated from the host contract and accounted for separately if: (i) the economic characteristics and risks of the host contract and the embedded derivative are not closely related; (ii) a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative; and (iii) the combined instrument is not measured at fair value through profit or loss. Changes in the fair value of separable embedded derivatives are recognized immediately in profit or loss.

Non-current assets held for sale

Non-current assets and disposal groups classified as held for sale are measured at the lower of carrying amount and fair value less costs to sell. Non-current assets and disposal groups are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is regarded as met only when the sale is highly probable and the asset or disposal group is available for immediate sale in its present condition. Management must be committed to the sale, which should be expected to qualify for recognition as a completed sale within one year from the date of classification. Oil and gas properties, property, plant and equipment and intangible assets once classified as held for sale are not depreciated.

Exploration and evaluation expenditures

In line with IFRS 6, pre-license costs, defined as those costs incurred before the legal right to explore has been acquired, are expensed in the period in which they are incurred. Exploration and evaluation costs of a type that are not sufficiently closely related to a specific mineral resource to support capitalization are also expensed in the period in which they are incurred.

Exploration and evaluation costs associated with oil, gas and mineral exploration and investments are capitalized on a project by project basis (well, field or specific exploration licenses, as appropriate), pending determination of the technical feasibility and commercial viability of the project. Costs incurred include appropriate technical (geological and geophysical "G & G"), license acquisition and directly attributable operational overhead. Amounts recorded for these assets represent costs and are not intended to reflect present or future values.

The recoverability of all exploration and evaluation expenditures is dependent upon the discovery of economically recoverable reserves and future profitable production or proceeds from the disposition thereof. When proven reserves are assigned, the accumulated costs for the relevant area are transferred from exploration and evaluation assets to oil and gas properties and further classified as either "Developed Oil & Gas Assets" or "Production Facilities and Equipment" (tangible fixed assets), as appropriate.

Oil and gas properties

The drilling of development wells (including unsuccessful development or delineation wells) as well as expenditures on the construction, installation or completion of infrastructure facilities such as pipelines are capitalized within oil and gas properties. The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning obligation, and, for qualifying assets, borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. Within oil and gas properties, developed oil and gas assets and production facilities and equipment (tangible fixed assets) are stated at cost less accumulated depletion, depreciation and amortization along with accumulated impairment losses. When significant parts of an item of oil and gas properties have different useful lives, they are accounted for as separate items (componentized) and depreciated at that level.

The cost of oil and gas properties is amortized over total estimated proven and probable reserves using the unit-of-production method. Costs are amortized only once commercial reserves associated with a development project can be determined and commercial production has commenced.

The unit-of-production rate is calculated by reference to the ratio of production volumes during the period to the related proven and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves.

Changes in factors such as estimates of proven and probable commercial reserves that affect unit-of-production calculations do not give rise to prior financial period adjustments and are dealt with on a prospective basis.

Impairment - Exploration and evaluation expenditures
Exploration and evaluation assets are assessed for impairment if:
(i) sufficient data exists to determine technical feasibility and commercial viability; or
(ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

Sufficient data is considered to exist in order to determine the technical feasibility and commercial viability of extracting a mineral resource when proven reserves are assigned. A review for indicators of impairment on a project by project basis (well, field or specific exploration licenses, as appropriate) is carried out, at least annually, to ascertain whether proven reserves have been assigned. If proven reserves have been assigned, exploration and evaluation assets attributable to those reserves are first tested for impairment (and any resulting impairment loss is recognized) and then reclassified from exploration and evaluation assets to oil and gas properties and amortized over the estimated life of the proven and probable reserves on a unit-of-production basis.

Exploration and evaluation costs for which technical feasibility has not yet been determined through the assignment of proven reserves are subject to technical, commercial and management review for indicators of impairment at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this intent no longer exists, such facts and circumstances might indicate that the carrying amount exceeds the recoverable amount. If this is the case, the costs are written off. Costs associated with an exploratory dry hole are expensed immediately if commercially viable quantities of hydrocarbons are not found. Where a license is relinquished or project abandoned, the related costs are written off. Where the Trust maintains an interest in a project, but the value of the project is considered to be impaired, a provision against the relevant capitalized costs will be provided.

For purposes of impairment testing, exploration and evaluation assets are allocated and added to the carrying amount of any oil and gas properties in the same cash-generating unit ("CGU") and the combined carrying amount is tested for impairment by comparing the carrying amount to the recoverable amount.

Impairment - Oil and gas properties
Oil and gas properties (which are further classified as developed oil and gas assets and production facilities and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Oil and gas properties are grouped into CGU's for impairment testing. The Trust has grouped its oil and gas properties into one CGU, the Salt Flat Field. An impairment loss is recognized for the amount by which the asset's carrying amount exceeds its recoverable amount.

Decommissioning provision
Provision is made for the present value of the future cost of abandonment (dismantling, decommissioning, and site disturbance remediation activities) of oil and gas wells and related facilities using a risk free rate of 4.0%. This provision is recognized when the legal or constructive obligation to abandon arises. The estimated costs, based upon engineering cost levels prevailing at the balance sheet date, are computed on the basis of the latest assumptions as to the scope and method of abandonment. The corresponding amount is

capitalized as part of exploration and evaluation assets or oil and gas properties and is amortized on a unit-of-production basis as part of the depreciation, depletion and amortization charge.

The increase in the provision due to the passage of time (“accretion”) is treated as a component of finance costs.

Any adjustments to the provision arising from reassessment of the estimated cost of decommissioning are added to, or deducted from the cost of the related asset in the current period. If a decrease in the liability exceeds the carrying amount of the asset, the excess is recognized immediately in profit or loss.

Property, plant and equipment

Property, plant and equipment is composed of non-oil and gas assets and is stated in the balance sheet at cost, less accumulated depreciation and any provision for impairment.

The initial cost of an asset comprises its purchase price or construction cost and any costs directly attributable to bringing the asset into operation. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

Property, plant and equipment is depreciated on a straight line basis at rates sufficient to write off the cost, less estimated residual values, of individual assets over their estimated useful lives, as follows:

Improvements to leasehold property	2-10 years (or over the remaining life of the lease if shorter)
Office furniture, fixtures and equipment	3-10 years
Computer equipment	2 years

The assets’ residual values and useful lives are reviewed, and adjusted if appropriate, at each balance sheet date.

Revenue recognition

Revenue comprises the fair value of the consideration received or receivable for the sale of hydrocarbons in the ordinary course of the Trust’s activities. Revenue is shown net of royalties, and intercompany sales are eliminated during consolidation. With respect to royalties, the Trust is acting as a collection agent on behalf of others.

Revenue is recognized when the amount can be reliably measured, it is probable that future economic benefits will flow to the Trust and when specific criteria have been met as described below. The amount of revenue is not considered to be reliably measurable until all contingencies relating to the sale have been resolved. The Trust bases its estimates on historical results, taking into consideration the type of customer, the type of transaction, the nature of the product and the specifics of each arrangement.

Revenues from the sale of crude oil and natural gas sales are recognized when the significant risks of loss and rewards of ownership have transferred, when legal title passes to the third-party purchaser. This is generally at the time the product enters collection facilities or pipeline facilities. The Trust uses the entitlement method to account for revenue whereby revenue recognition is based upon the Trust's direct ownership interest in the underlying oil and gas properties.

Costs associated with the sale of crude oil and natural gas such as taxes, operating costs and transportation expenses are reflected in cost of sales.

Unit based compensation

The Trust uses the fair value method of valuing compensation expense associated with the Trust's unit option plan. The units issued pursuant to the option plan are not considered equity settled stock based compensation since the IAS 32 "puttable instrument exemption" does not extend to unit based payments made by a Trust. Therefore, options issued subject to the option plan are treated similar to a cash settled stock based compensation arrangement, with the associated liability being fair-valued at the end of each reporting period and the corresponding change to fair value being recognized in the income statement.

The Trust has established other unit based compensation plans whereby notional units are granted to employees. The fair value of these notional units is estimated and recorded as a cash settled unit based compensation arrangement. The offsetting amount is recorded as accrued liabilities or other long-term liabilities. A realization of the expense and a resulting reduction in cash provided by operating activities occurs when a cash payment is made.

Finance income and expense

Finance expense comprises interest expense on borrowings, amortization of deferred financing costs, bank fees and accretion of the discount on the decommissioning provision.
Interest income is recognized as it accrues in profit or loss, using the effective interest method.

Unitholder distributions

Unitholder distributions are declared and paid monthly. Unitholders' equity is reduced by the amount of the declared dividend at the record date.

Taxation

Income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity. Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. The effect of any change in income tax rates is recognized in the current period income. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

Eagle Energy Trust is a taxable entity under the Income Tax Act (Canada) ("Tax Act") and is currently taxable only on income that is not distributed or distributable to the unitholders. Eagle Energy Trust distributes all of its taxable income to the unitholders and expects to continue to distribute all of its taxable income to unitholders. The Trust will at no time be a SIFT trust as defined in the Tax Act. Investment restrictions contained in the formation documents provide that the Trust and its subsidiaries will only invest in entities that qualify as a "portfolio investment entity" and will not hold any "non-portfolio property" or "taxable Canadian property", each as defined in the Tax Act. It also qualifies as a "mutual fund trust" within the meaning of the Tax Act and will not be subject to the limit on non-resident ownership in the Tax Act as it will not own any "taxable Canadian property" as defined in the Tax Act.

Eagle Energy Trust's indirect subsidiary is in the business of acquiring, developing and producing oil and natural gas reserves in the United States. As a general rule, a foreign corporation engaged in a United States trade or business is subject to U.S. federal income tax on income that is effectively connected (effectively connected income, or "ECI") with the United States trade or business and, if an income tax treaty with the United States applies, is attributable to a permanent establishment maintained by the foreign corporation in the United States. ECI is subject to United States federal income tax on a net basis at the regular United States federal graduated rates of tax that apply to United States persons. A foreign corporation's taxable income is computed by claiming deductions that are attributable to the effectively connected gross income on a timely filed return. A foreign corporation that derives ECI (including amounts received as a partner through a partnership or disregarded entity) is generally required to make quarterly payments of estimated United States tax, and is required to file a United States federal income tax return. A subsidiary of Eagle Energy Trust, Eagle Energy Commercial Trust, has elected under applicable United States Treasury Regulations to be treated as a corporation for United States federal income tax purposes effective on the date of formation and is generally subject to United States federal income tax on its net taxable income (including income related to the Salt Flat Interest which is ECI.) Eagle Energy Commercial Trust deducts interest paid on certain intercompany notes and other deductible expenses, including intangible drilling and developments costs and depletion in calculating its US taxable income.

Trust unit calculations
The Trust uses the treasury stock method to determine the dilutive effect of trust unit rights and trust unit options. Under the treasury stock method, outstanding and exercisable instruments that will have a dilutive effect are included in per-unit diluted calculations, ordered from most dilutive to least dilutive.

The dilutive effect of convertible obligations or instruments is determined using the "if-converted" method, whereby the outstanding convertibles at the end of the period are assumed to have been converted at the beginning of the period or at the time of issue if issued during the period. Amounts charged to income or loss which relate to the outstanding convertibles are added back to net income for the diluted calculation. The units issued upon conversion are included in the denominator of per-unit basic calculations from the date of issue.

3. Critical accounting estimates and judgments
The Trust makes estimates and assumptions concerning the future. The resulting accounting estimates will, by definition, seldom equal the related actual results. Such estimates and assumptions are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below.

Estimation of oil and gas reserves
Oil and gas reserves are the estimated quantities of oil and gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of oil and gas reserves are inherently imprecise, require the application of judgment and are subject to future revision. Accordingly, financial and accounting measures (such as the impairment calculation, depreciation, depletion and amortization charges, and decommissioning provisions) that are based on reserves are also subject to change.

Capitalized exploration and evaluation expenditures
In making decisions about whether to continue to capitalize exploration and evaluation expenditures, it is necessary to make judgments about the commercial reserves and the level of activities that constitute on-going evaluation determination. If there is a change in any judgment in a subsequent period, then the related capitalized exploration and evaluation expenditure would be expensed in that period, resulting in a charge to income.

Decommissioning provision
Estimates of the amounts of provision for decommissioning recognized are based on current legal and constructive requirements, technology and price levels. As actual outflows may be different from estimates due to changes in laws, regulations, technology, prices and conditions, and can take place in the future, the carrying amounts of provisions are regularly reviewed and adjusted to take account of such changes. The Trust has interpreted the

accounting standard to use the risk-free discount rate for calculating the present value of the decommissioning obligation.

Impairment indicators
The recoverable amounts of cash-generating units and individual assets have been determined based on the higher of value-in-use calculations and fair values less costs to sell. These calculations require the use of estimates and assumptions. It is reasonably possible that the commodity price assumption may change, which may impact the estimated life of the asset and may require a material adjustment to the carrying value of assets. The Trust monitors internal and external indicators of impairment relating to its tangible and intangible assets.

Income taxes
The Trust recognizes the net future tax benefit related to deferred income tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of deferred income tax assets requires the Trust to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Trust to realize the net deferred tax assets recorded at the balance sheet date could be impacted.

Additionally, future changes in tax laws in the jurisdiction in which the Trust operates could limit the ability of the Trust to obtain tax deductions in future periods.

Derivative financial instruments
As described in "Financial risk management" note 5, derivative financial instruments are used by the Trust to manage its exposure to market risks relating to commodity prices. The Trust's policy is not to use derivative financial instruments for speculative purposes. Derivative financial instruments that do not qualify, or are not designated, as hedges for accounting are recorded at fair value. Instruments are recorded in the balance sheet as either an asset or a liability with changes in fair value recognized in the income statement. The estimate of fair value of all derivative instruments is based on quoted market prices, or in their absence, third-party market indications and forecasts. The estimated fair value of financial assets and liabilities is subject to measurement uncertainty.

Classification of trust units as equity
Trust units issued by the Trust give the holder the right to put the units back to the issuer in exchange for cash. IAS 32 "Financial Instruments: Presentation" establishes the general principle that an instrument which gives the holder the right to put the instrument back to the issuer for cash should be classified as a financial liability, unless such instrument has all of the features and meets the conditions of the IAS 32 "puttable instrument exemption". If these "puttable instrument exemption" criteria are met, the instrument is classified as equity. The Trust has examined the terms and conditions of its Trust Indenture and classifies its outstanding trust units as equity because the trust units meet the "puttable instrument exemption" criteria as there is no contractual obligation to distribute cash.

Contingencies
By their nature, contingencies will only be resolved when one or more future events occur or fail to occur. The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events

4. Determination of fair values
A review of the financial statements has concluded that there are no significant differences between the book values and fair values of the financial assets and liabilities of the Trust as at March 31, 2011 and December 31, 2010.

5. 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 the Trust's exposure to each of the above risks, the Trust's objectives, policies and processes for measuring and managing risk, and the Trust's management of capital. Further quantitative disclosures are included throughout these consolidated financial statements.

The Trust finances its operations through a combination of cash, loans from banks (lines of credit) and equity. Finance requirements such as equity, debt and project finance are reviewed by the Board when funds are required for acquisition, exploration and development projects.

The Trust's treasury management function is responsible for managing funding requirements and investments which include banking and cash flow management. Interest and foreign exchange exposure are key functions of treasury management to ensure adequate liquidity at all times to meet cash requirements.

The principal financial instruments of the Trust are cash held in banks, trade receivables and financial liabilities. These instruments are for the purpose of meeting its requirements for operations.

Credit risk
Credit risk is the risk of financial loss to the Trust if a customer or counterparty to a financial instrument fails to meet its contractual obligations and arises principally from the Trust's receivables from its oil marketer. The maximum exposure to credit risk was as follows:

As at:	March 31, 2011	December 31, 2010
Cash and cash equivalents	$ 23,632,821	$ 31,731,118
Trade and other receivables	4,138,033	1,310,287
	$ 27,770,854	$ 33,041,405

Cash and cash equivalents:

The Trust limits its exposure to credit risk by investing only in liquid securities and only with counterparties with a strong credit rating. Given this approach, Management does not expect any counterparty to fail to meet its obligations and did not have any such investments at March 31, 2011 and December 31, 2010.

Trade and other receivables:

The Trust's operations are conducted in the United States. Exposure to credit risk is primarily influenced by the individual characteristics of each customer.

Receivables from the Trust's oil marketer are normally collected in the month following production. The Trust's policy to mitigate credit risk associated with these balances is to establish marketing relationships with reputable purchasers with good credit. The Trust historically has not experienced collection issues with its oil and natural gas marketer. The Trust does not typically obtain collateral from oil and natural gas marketers.

The Trust does not anticipate any default as it transacts with creditworthy customers and Management does not expect any losses from non-performance by these customers. As such, no provision for doubtful accounts has been recorded at March 31, 2011 and December 31, 2010.

The maximum exposure to credit risk for loans and receivables at the reporting dates by type of customer was:

As at:	March 31, 2011	December 31, 2010
Oil and natural gas marketing companies	$ 2,663,485	$ 1,303,979
Cash calls paid to operator	1,471,120	-
Other	3,428	6,308
	$ 4,138,033	$ 1,310,287

The Trust's most significant customer, a US oil and natural gas marketer, accounted for approximately 64% or $2,663,485 of trade receivables at March 31, 2011 and 100% or $1,303,979 at December 31, 2010. As of March 31, 2011 and December 31, 2010 the receivables were considered current (less than 90 days or three months old).

Liquidity risk

Liquidity risk is the risk that the Trust will not be able to meet its financial obligations as they fall due. The approach to managing liquidity is to ensure, as far as possible, that the Trust will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Trust's reputation.

At March 31, 2011, the Trust had a working capital surplus of approximately $16 million. In addition, the Trust had an $US 8 million credit facility of which $US 8 million was available at March 31, 2011 (refer to "Borrowings" note 25). To better manage its liquidity risk, the Trust prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Trust utilizes authorizations for expenditures

("AFEs") on both operated and non-operated projects to manage capital expenditures. The Trust attempts to match its payment cycle with the collection of its oil and natural gas revenue each month.

The following are the contractual maturities of financial liabilities, including estimated interest payments, as applicable, at March 31, 2011:

	Carrying amount	Contractual cash flows	Less than one year	One – two years	Two – five years	More than five years
Trade and other payables	$ 8,780,925	$ 7,897,506	$ 7,897,506	$ -	-	-
Distributions payable	1,576,013	1,576,013	1,576,013			
Risk management liability	1,414,002	1,414,002	1,355,339	58,663		
	$ 11,770,940	$ 10,887,521	$ 10,887,521	$ 58,663	-	-

Contractual cash flows exclude the current portion of unit based compensation, see note 23.

The Trust units contain a redemption feature, see "Trust capital" note 27. Utilizing the terms of redemption as outlined in note 27, the total market redemption price for all outstanding units at March 31, 2011 would be $187,009,123 ($11.79 x 90% x 17,624,081). As the maximum cash outlay required by the Trust is capped at $100,000 per month or $1,200,000 per year, the Trust would have approximately 155 years to pay out this commitment.

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 usually 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. The Trust, however, may give consideration in certain circumstances to the appropriateness of entering into long term, fixed price marketing contracts.

During the quarter ended March 31, 2011 the Trust entered into three financial contracts to mitigate the effects of fluctuating prices on a portion of its production as follows:

1. A costless collar contract for 200 bbls of oil per day with a February 2011 through January 2012 term at a floor of $US 85.00 per barrel and a ceiling of $US 100.00 per barrel.
2. A costless collar contract for 200 bbls of oil per day with a May 2011 through April 2012 term at a floor of $US 88.00 per barrel and a ceiling of $US 107.55 per barrel.
3. A fixed contract to sell 100 bbls of oil per day with a May 2011 through April 2012 term at a price of $US 101.00 per barrel.

For the period ended, and as of December 31, 2010, the Trust did not enter into any financial derivative instruments nor were there any outstanding contracts.

Net Fair Value of Financial Derivative Positions as at March 31, 2011

	Volume	Measure	Beginning	Term	Floor $US	Ceiling $US	Fair Value $CA
Oil Fixed Price							
NYMEX (i)	200	bbls/d	Feb-11	Jan-12	85.00	100.00	$ 681,491
NYMEX (i)	200	bbls/d	May-11	Apr-12	88.00	107.55	484,379
NYMEX (ii)	100	bbls/d	May-11	Apr-12		101.00	248,132
							$ 1,414,002

(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).

Net Risk Management Position as at March 31, 2011	
Current liability	$ 1,355,339
Non-Current liability	58,663
Net Risk Management Liability	$ 1,414,002

The total net fair value of Eagle's unrealized risk management positions is $1,414,002 at March 31, 2011, and has been calculated using both quoted prices in active markets and observable market-corroborated data.

Reconciliation of Unrealized Risk Management Positions For the Three Months Ended March 31, 2011	Fair Value	Total Unrealized Loss
Fair value of contracts entered into	$ 1,432,227	$ 1,432,227
Fair value of contracts realized	(18,225)	(18,225)
Change in fair value of beginning and new contracts	-	-
Fair value of contracts as at March 31, 2011	$ 1,414,002	$ 1,414,002

Earnings Impact of Realized and Unrealized Losses For the Three Months Ended March 31, 2011	Realized Loss	Unrealized Loss	Total Net Loss
Risk management loss	$ 18,225	$ 1,414,002	$1,432,227
Net loss on risk management	$ 18,225	$ 1,414,002	$ 1,432,227

A 10% change in the market price of oil would have increased (decreased) profit or loss by approximately $143,000. This analysis assumes that all other variables, in particular interest rates, remain constant.

Foreign exchange risk:

Foreign exchange risk is the risk that future cash flows will fluctuate as a result of changes in market foreign exchange rates. The Trust's operating cash flows are generated in US dollars and distributions are declared in Canadian dollars. As a consequence, there is an element of foreign exchange risk to the Trust. The Trust's treasury management function is responsible for managing funding requirements and investments, which include banking and cash flow management. Prices for oil are determined in global markets and generally denominated in US dollars. Generally an increase in the value of the $CA as compared to the $US will reduce the prices received by the Trust for its petroleum and natural gas sales but will also reduce the operating expenses associated with those sales, as well as reduce the price paid by the subsidiary of the Trust for additional asset acquisitions.

The following financial instruments were denominated in U.S. dollars:

As at March 31, 2011	$US	$CA
Cash and cash equivalents	$ 3,260,430	$ 3,161,965
Trade and other receivables	4,264,238	4,134,605
Trade and other payables	(7,715,763)	(7,481,204)
	$ (191,095)	$ (184,634)

The average exchange rate during the quarter was $US 1 equal to $CA .9860, and the exchange rate at March 31, 2011 was $US 1 equal to $CA .9696.

A 10% change in the Canadian dollar against the US dollar at March 31 would have increased (decreased) profit or loss by approximately $18,000. This analysis assumes that all other variables, in particular interest rates, remain constant.

As at December 31, 2010	$US	$CA
Cash and cash equivalents	$ 339,853	$ 338,018
Trade and other receivables	1,313,954	1,306,859
Trade and other payables	(5,134,489)	(5,106,763)
	$ (3,480,682)	$ (3,461,886)

The average exchange rate during the period was $US 1 equal to $CA 1.0077, and the exchange rate at December 31, 2010 was $US 1 equal to $CA .9946.

A 10% change in the Canadian dollar against the US dollar at December 31 would have increased (decreased) profit or loss by approximately $321,000. This analysis assumes that all other variables, in particular interest rates, remain constant.

Interest rate risk:

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Trust may be exposed to interest rate risk at both fixed and variable rates as it borrows funds. There were no draws against the credit facility during the quarter and no amounts outstanding as of March 31, 2011 and December 31, 2010. Therefore, the Trust had no interest rate risk, and as a result, the Trust did not hedge against any interest rate exposure.

Capital management

The Trust's policy is to maintain a strong capital base so as to maintain investor, creditor and market confidence and to sustain future development of the business. The Trust manages its capital structure and makes adjustments to it based upon economic conditions and the risk characteristics of the underlying oil and natural gas assets. The Trust considers its capital structure to include working capital, loans and borrowing, and unitholders' equity. In order to maintain or adjust the capital structure, the Trust may issue units, engage in external debt financing, and adjust its capital spending to manage current and projected debt levels.

The Trust monitors capital based on the ratio of external debt to cash generated from operations. This ratio is calculated as external debt, defined as outstanding loans and borrowings, divided by annualized cash generated from operations before changes in non-cash working capital. Management's objective is to maintain an external debt to estimated future annual cash flows not to exceed 1.5 to 1.0. This ratio may increase at certain times as a result of acquisitions. In order to facilitate the management of this ratio, the Trust prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors.

As at March 31, 2011 and December 31, 2010, the Trust's ratio of external debt to annualized cash flow was 0 to 1, within the range established by the Trust, and due to there being no outstanding debt.

There were no changes in the Trust's approach to capital management during the period.
Any draws against the existing credit facility would be subject to established covenants. The credit facilities are subject to a semi-annual review of the borrowing base which is directly impacted by the value of the oil and natural gas reserves. See "Borrowings" note 25.

6. Subsidiaries and consolidated entities

The following table summarizes the structure of the Trust following completion of the initial public offering and the indirect investment by the Trust in the Partnership (Eagle Energy Acquisitions LP). All subsidiaries of the Trust are directly or indirectly wholly-owned by the Trust.

Subsidiary	Country of Formation	Nature of Business	Footnotes
Eagle Energy Commercial Trust	Canada	Alberta Trust	(1)
Eagle Energy Acquisitions LP	United States	Delaware, LP	(2)
Eagle Energy US GP LLC	United States	Delaware, LLC	(3)

(1) On September 28, 2010, Eagle Energy Commercial Trust, an unincorporated open ended trust established under the laws of the Province of Alberta, was formed by way of a trust indenture. All outstanding Eagle Energy Commercial Trust Units are owned by the Trust. Eagle Energy Commercial Trust units are issued only when fully paid in money, property or past services and are not subject to future calls or assessments. Eagle Energy Commercial Trust was created to acquire and hold a 99.999% interest in Eagle Energy Acquisitions LP.

(2) On September 28, 2010, Eagle Energy Acquisitions LP, a limited partnership, was created by Eagle Energy Commercial Trust by way of a certificate of limited partnership. Eagle Energy Acquisitions LP is a limited partnership formed under the laws of the State of Delaware with a general mandate to engage in the business of acquiring, developing and producing oil and natural gas reserves in the United States.

(3) On September 28, 2010, Eagle Energy US GP LLC was formed to be the general partner of and acquire and hold the remaining 0.001% interest in Eagle Energy Acquisitions LP. Eagle Energy US GP LLC is a limited liability company formed under the laws of the State of Delaware. The sole member of Eagle Energy US GP LLC is Eagle Energy Commercial Trust.

The results of the above subsidiaries, together with Eagle Energy Inc. (as further described below) have been included in the consolidated financial statements. All of the entities have calendar year ends.

Eagle Energy Inc. is the Administrator of the Trust and was formed under the laws of the Province of Alberta on March 28, 2008. The sole shareholder of Eagle Energy Inc. is EEI Holdings Inc. and the sole shareholder of EEI Holdings Inc. is Richard Clark, Chief Executive Officer of the Administrator. Eagle Energy Inc. is not a legal subsidiary of the Trust, the Trust has no voting rights in Eagle Energy Inc. and the Trust cannot appoint or remove the directors of Eagle Energy Inc.

However, Computershare Trust Company of Canada, the Trustee of Eagle Energy Trust, has delegated much of the responsibility for conducting the Trust's affairs to the Administrator, Eagle Energy Inc., pursuant to an administrative services agreement. The Board of Directors of the Administrator therefore performs the majority of the oversight and governance role for the Trust. As Trust Administrator Eagle Energy Inc. performs services pursuant to the administrative services agreement on a cost recovery basis and no additional fees are payable by the Trust to the Administrator.

EEI Holdings Inc. (the sole shareholder of Eagle Energy Inc.) has entered into a voting agreement which entitles unitholders of the Trust to elect 100% of the directors of Eagle Energy Inc. EEI Holdings Inc. has also waived certain shareholder rights, including the right to appoint an auditor, dissent rights, and oppression rights. Eagle Energy Inc. is therefore controlled exclusively by the unitholders of the Trust.

Eagle Energy Inc. meets the accounting definition of a special purpose entity and accordingly Eagle Energy Inc. has been consolidated based on the principles set out in *SIC 12 Consolidation – Special Purpose Entities.*

7. Acquisitions

On November 24, 2010, Eagle acquired an average 73% working interest in the Salt Flat Field (a light oil producing property located in south central Texas) from OAG Holdings LLC for total consideration, including closing adjustments, of $127.1 million. The acquisition had an effective date of June 1, 2010 and a closing date of November 24, 2010.

Consideration consisted of cash and 2,000,000 trust units of Eagle valued at $10.00 per trust unit, being the initial public offering price of the units on the closing date of the acquisition.

The purchase price allocation is as follows:

Identifiable assets acquired and liabilities assumed:	
Oil and Gas Properties	$127,279,122
Provision (i)	(139,761)
Total	$127,139,361

The consideration paid or payable is as follows:	
Cash at closing	$105,316,897
Trust units issued at closing	20,000,000
Owing to vendor at year end for final adjustments	1,822,464
	$127,139,361

(i) Relates to the decommissioning obligation assumed

Had this transaction closed on July 20, 2010, the formation date of the Trust, the additional revenue, net of royalties, would have been approximately $US 3,439,000 for the period ended December 31, 2010.

8. 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 expense 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 an office in Houston, Texas. The Trust's head office is in Calgary, Alberta, Canada. 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. Revenue is presented net of royalties as noted in the following table.

For the Three Months Ended March 31, 2011	
Revenue before royalties	$ 9,864,775
Royalties	(2,729,358)
	$ 7,135,417

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

9. Cost of sales

For the Three Months Ended March 31, 2011	
Operating costs	$ 1,311,453
Depreciation, depletion and amortization	2,889,061
	$ 4,200,514

10. Unit based payments

The following table reconciles unit based compensation expense.

For The Three Months Ended March 31, 2011			Reference
Cash paid on performance option surrender	$	-	Note 10 (a)
Units issued on performance option surrender		634,427	Note 10 (a)
Restricted unit rights issued		824,555	Note 10 (b)
Unit options issued		1,315,873	Note 10 (c)
Total unit based compensation expense	$	2,774,856	

Grant, Surrender and Replacement of Performance Options
On September 14, 2010, 775,000 performance options were granted as compensation to persons who provided substantial services and expertise in the creation of the Trust and sourcing the acquisition of the Salt Flat Interest. After determining that the performance options would not meet imposed regulatory requirements, the Trust entered into performance option exchange and escrow agreements with holders of the 775,000 performance options that saw holders surrender their performance options, concurrent with the November 24, 2010 closing of the Trust's initial public offering, in exchange for:

(i) Cash and units equal to the fair market value of the performance options; and
(ii) Cash settled Restricted Unit Rights ("RURs") to capture the foregone distributions and capital appreciation resulting from the fewer number of units that were being issued in exchange for the surrendered performance options.

Note (a)
Cash and Units Issued Upon Surrender of Performance Options
The Trust paid $992,000 in cash and issued 387,500 units upon surrender of the performance options. This equated to one-half of a unit and $1.28 cash for each performance option surrendered.

The Trust withheld the cash to pay taxation agencies the tax that would result from the holders disposing of their performance options. The fair value estimate associated with the cash component, $992,000, was immediately expensed in the income statement. At March 31, 2011 and December 31, 2010, $96,000 is included in trade and other payables related to remaining amounts estimated to be payable to taxation agencies.

The 387,500 units were escrowed, with escrow releases as to two-thirds on September 14, 2012 and the remaining one-third on September 14, 2013. The fair value estimate associated with the escrowed units is expensed in the income statement over the escrow period with the offsetting entry to other long-term liabilities. At March 31, 2011, $840,332 was included in other long-term liabilities relating to these units and at December 31, 2010, $205,905. Upon release from escrow, the related accumulated liability will be transferred to the trust capital account in unitholders equity. At March 31, 2011, the fair value of the 387,500 units was recalculated. The Trust is required to recalculate the fair value of the liability related to these escrowed units at the end of each reporting period. The following schedule shows the continuity of escrowed units issued upon surrender of performance options:

For the Three Months Ended March 31, 2011	
Balance, beginning of period	387,500
Issued	0
Balance, end of period	387,500
Number of units in escrow	387,500

The fair value of the escrowed units was assumed to be equal to the March 31, 2011 closing unit price of $11.89 per unit. A forfeiture rate of 5% was used and, due to the limited history of the Trust, this figure is an estimated expected rate.

Note (b)
Cash Settled RURs Issued Upon Surrender of Performance Options
The Trust issued 775,000 RURs, which equated to one RUR for each performance option. Each RUR entitles the holder to receive cash payments equal to the distributions payable on one unit as well as capital appreciation of units. RURs vest as to two-thirds on September 14, 2012 and the remaining one-third on September 14, 2013. Until vested, RUR payments will be accrued for the benefit of the holders. Holders of the RURs are entitled to receive a cash payment equal to accrued distributions and capital appreciation, once the RURs vest.

The fair value estimate associated with the RURs is expensed in the income statement over the vesting period with the offsetting entry to other long-term liabilities. At March 31, 2011, $988,044 was included in other long term liabilities relating to these RURs and at December 31, 2010, $163,489. At March 31, 2011, the fair value of the 775,000 RURs was recalculated. The Trust is required to recalculate the fair value of the liability at the end of each reporting period.

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

For the Three Months Ended March 31, 2011	
Balance, beginning of period	775,000
Issued upon surrender of performance options	0
Balance, end of period	775,000
Number of restricted unit rights vested	nil

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

As at March 31, 2011		
Fair value at the balance sheet date	$	6.99
Volatility		33%
Life of restricted unit rights		9.8 years
Risk-free interest rate		3.2%

A forfeiture rate of 5% was used and, due to the limited history of the Trust, this figure is an estimated expected rate.

Note (c)
Unit Option Plan
The Trust has an option plan that entitles directors, officers, employees and certain consultants to purchase units of the Trust. The purpose of the option plan is to aid in attracting, retaining and motivating eligible employees and other service providers by enabling such persons to participate in the growth and development of the Trust.

Options are granted at a price equal to the fair market value of the units at the time of grant. The option exercise price is reduced by the amount of distributions paid on the units subsequent to the date of grant, subject to certain conditions specified by the option plan. The options have a 10 year term and vest as to one-third on each of the first, second and third anniversaries of the date of grant. Options granted are not subject to any performance criteria apart from, in respect of directors and employees and certain consultants, their continued service with or employment by the Trust. Options are forfeited if the option holder leaves before the options vest.

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

	March 31, 2011	
	Number of options	Weighted average exercise price
Outstanding, beginning of period	1,300,000	$ 9.72
Forfeited during the period	–	–
Exercised during the period	–	–
Granted during the period	42,500	10.83
Outstanding at end of period	1,342,500	$ 9.76
Exercisable at end of period	–	$ –

The range of exercise prices of the outstanding options is as follows:

	Weighted average exercise price	Weighted average contractual life (years)
$9.72 - $10.83	$ 9.76	9.7

No unit options were exercised during the period.

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

As at March 31, 2011	
Fair value at the balance sheet date	$ 6.11
Unit price	$11.89
Exercise price	$9.76
Volatility	33%
Option life	9.7 years
Distributions – none estimated, due to declining strike price feature	0%
Risk-free interest rate	3.2%

A forfeiture rate of 5 % was used and due to the limited history of the Trust, this figure is an estimated expected rate. This estimate will be adjusted to the actual forfeiture rate.

The fair value estimate associated with the options is expensed in the income statement over the vesting period with the offsetting entry to either trade and other payables or other long-term liabilities. At March 31, 2011, $883,420 was included in trade and other payables and $736,183 was included in other long-term liabilities relating to this option plan. At December 31, 2010, $165,670 was included in trade and other payables and $138,059 was included in other long-term liabilities. At March 31, 2011, the fair value of the options was recalculated. The Trust is required to recalculate the fair value of the liability at the end of each reporting period.

The closing trading price of the Trust's units at March 31, 2011 was $11.89 per unit.

11. Foreign exchange

The Trust has recognized the following in the profit or loss on account of foreign currency fluctuations:

For the Three Months Ended March 31, 2011	
Net gain arising on settlement of foreign currency transactions arising out of operating activities	$ 518,346

The Trust has recognized the following in unitholders' equity due to the translation of its US subsidiary, which has a US dollar functional currency, to the presentation currency of the Trust, being the Canadian dollar, for financial statement presentation:

For the Three Months Ended March 31, 2011	
At December 31, 2010	$ (4,366,120)
Foreign currency translation (loss)	(3,795,035)
At March 31, 2011	$ (8,161,155)

The currency in which these transactions and balances are primarily denominated is US dollars, and as such, the Trust is not exposed to significant foreign exchange risk. See "Financial risk management" note 5.

12. Finance expense

For the Three Months Ended March 31, 2011	
Amortized application fees on revolving line of credit	$ 17,623
Standby and bank fees	10,559
Change in fair value of financial assets and liabilities	-
Accretion of decommissioning provision	2,123
Net finance expense recognized	$ 30,305

13. 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:

For the Three Months Ended March 31, 2011	
Loss before taxation	$ (1,911,011)
Expected tax rate	35%
Expected income tax recovery	(668,854)

Decrease (Increase) in recovery resulting from:		
Non-deductible items - permanent differences		
Administrative expenses of the Trust	35%	181,543
Unit based compensation	35%	971,200
Foreign exchange gain, net	35%	(181,421)
Risk management loss	35%	501,279
Current year losses for which no deferred tax asset was recognized	35%	113,554
Items deductible at the subsidiary level		
Interest on internal debt of subsidiary	35%	(919,460)
Other	35%	2,159
Total income tax recovery	35%	$ -

14. Depreciation, depletion and amortization

Depreciation, depletion and amortization are included with the following headings in the income statement for the three months ended March 31, 2011:

	Oil and gas properties	Property, plant and equipment	Total
Cost of sales	$ 2,889,061	$ -	$ 2,889,061
Administrative expenses	-	5,678	5,678
	$ 2,889,061	$ 5,678	$ 2,894,739

15. Loss per unit

Loss attributable to unitholders	$ (1,911,011)
Weighted average number of units outstanding	17,624,081
Basic and diluted loss per unit	$ (0.11)

Calculation

Basic loss per unit is calculated by dividing the loss attributable to owners of the Trust by the weighted average number of units outstanding during the period. Diluted loss per unit is calculated using the loss for the year divided by the weighted average number of units outstanding assuming the conversion of potentially dilutive equity instruments or derivatives outstanding.

Per Unit Amounts

Basic loss per unit for the period ended March 31, 2011 is based on 17,624,081 weighted average units outstanding. Diluted loss per unit is equal to basic loss per unit as the conversion of dilutive items would be anti-dilutive to loss per unit. Excluded from the number of units outstanding is the effect of the 387,500 units issued to certain directors, Management and a consultant on the surrender of previously granted performance options as well as 1,342,500 options as their effect is anti-dilutive. Refer to “Trust capital” note 27.

16. Cash and cash equivalents

As at:	March 31, 2011	December 31, 2010
Cash in banks	$ 23,632,821	$ 31,731,118

As of March 31, 2011 and December 31, 2010, there are no compensating balance arrangements that place restrictions on the use of available cash.

17. Trade and other receivables

As at:	March 31, 2011	December 31, 2010
Trade receivables	$ 4,134,605	$ 1,303,979
Other	3,428	6,308
	$ 4,138,033	$ 1,310,287

Trade receivables that are less than three months past due are not considered impaired. As of March 31, 2011 and December 31, 2010 there were no past due receivables and thus no balances against which a doubtful allowance has been provided.

18. Prepaid expenses

As at:	March 31, 2011	December 31, 2010
GST Tax	$ 16,090	$ 551
Insurance	40,833	60,865
Rent	53,174	-
Deposits	38,784	-
	$ 148,882	$ 61,416

The balances are not deemed impaired due to their current status.

19. Exploration and evaluation assets

At December 31, 2010	$ -
Additions	149,625
Transfers to oil and gas properties	(-)
At March 31, 2011	$ 149,625

As most of the activity in the Salt Flat field is focused on developing the existing proved and probable reserves, exploration and evaluation expenditures are limited.

20. Oil and gas properties

	Developed oil & gas assets	Production facilities and equipment	Capitalized future decom-missioning costs	Total
Cost				
At December 31, 2010	$ 126,566,973	$ 316,539	$ 217,380	$ 127,100,892
Additions	2,098,940	39,243	50,402	2,188,585
Transfers from exploration and evaluation	-	-	-	-
At March 31, 2011	$ 128,665,913	$ 355,782	$ 267,782	$ 129,289,477
Accumulated depreciation				
At December 31, 2010	$ (573,893)	$ (7,661)	$ -	$ (581,554)
Charge for the period	(2,845,207)	(38,771)	(5,083)	(2,889,061)
At March 31, 2011	$ (3,419,100)	$ (46,432)	$ (5,083)	$ (3,470,615)
Net book value				
At December 31, 2010	$ 125,993,080	$ 308,878	$ 217,380	$ 126,519,338
Net change	(746,267)	472	45,319	(700,476)
At March 31, 2011	$ 125,246,813	$ 309,350	$ 262,699	$ 125,818,862

Included in developed oil & gas asset balance at March 31, 2011 and December 31, 2010 is $123,789,875 of acquisition costs (comprised of the initial cost, see “Acquisitions” note 7, of $127,139,361 reduced by a December 31, 2010 translation adjustment of $3,349,486) associated with the Salt Flat Field acquisition.

21. Property, Plant and Equipment

	Improvements to leasehold property	Furniture, fixtures, and equipment	Computer equipment	Total
Cost				
At December 31, 2010	-	-	$ 34,739	$ 34,739
Additions	-	-	$ 26,643	$ 26,643
At March 31, 2011	-	-	$ 61,382	$ 61,382
Accumulated Depreciation				
At December 31, 2010	-	-	-	-
Charge for the period	-	-	(5,678)	(5,678)
At March 31, 2011	-	-	$(5,678)	$(5,678)
Net book value				
At December 31, 2010	-	-	$ 34,739	$ 34,739
Net change	-	-	20,965	20,965
At March 31, 2011	-	-	$ 55,704	$ 55,704

The additions for 2011 consist predominantly of computer hardware used in the general and administrative environment.

22. Other intangible assets

As at:	March 31, 2011	December 31, 2010
Deferred financing charges	$ 218,817	$ 218,817
Accumulated amortization	(25,112)	(7,488)
Net other intangible assets	$ 193,705	$ 211,329

Deferred financing charges represent the upfront fees and related costs to establish the credit facility, see “Financial risk management” note 5 regarding liquidity and “Borrowings” note 25. The term of the facility per the signed term letter and credit facility agreement is November 24, 2013, which is three years from the closing date. Although no amount was drawn and outstanding on the facility at March 31, 2011 or December 31, 2010, the Trust does intend to utilize the facility especially with regard to liquidity risk management. Therefore, the charges are being amortized over the initial three year life of the credit facility on a straight-line basis. Once amounts are drawn on the facility the charges will be amortized using the effective interest method.

23. Trade and other payables

As at:	March 31, 2011	December 31, 2010
Trade payables	$ 7,801,506	$ 6,423,951
Unit based compensation	3,447,978	673,123
Trust issue costs	-	459,931
Employment related taxes	96,000	96,000
Less long-term portion of unit based compensation	(2,564,559)	(507,453)
	$ 8,780,925	$ 7,145,552

Unit based compensation liability includes both a current and long-term portion. The long-term portion of $2,564,559 and $507,453 is reflected in the balance sheet category “Other long term liabilities”. Refer to “Unit based payments” note 10.

24. Distributions payable

As at:	March 31, 2011	December 31, 2010	Cumulative
Beginning balance	$ 1,916,432	$ -	$ -
Distributions declared	4,728,040	1,916,432	6,644,472
Less distribution paid	(5,068,459)	-	(5,068,459)
Outstanding distributions declared and payable	$ 1,576,013	$ 1,916,432	$ 1,576,013

Distributions are declared and paid monthly. The outstanding balance at March 31, 2011 represents the distribution declared March 15, 2011 that is to be paid April 21, 2011.

25. Borrowings

On November 24, 2010, Eagle Energy Acquisitions LP entered into a credit facility with a U.S. affiliate of a Canadian chartered bank. The credit facility is a $US 150 million three year senior secured revolving facility, with an initial borrowing base set at $US 8 million. The credit facility provides for a semi-annual evaluation. Borrowings will be either by way of a LIBOR or base rate option. The LIBOR and base rate margins above LIBOR or the base rate, as applicable, will be subject to a pricing grid based upon the percentage of utilization of the borrowing base, which range from 2.75% to 3.50% and 1.75% to 2.50%, respectively. Eagle Energy Acquisitions LP may only borrow under the credit facility in U.S. dollars. The credit facility is secured by a first priority security interest on substantially all of the oil and gas properties of Eagle Energy Acquisitions LP. Under the credit facility, Eagle Energy Trust, Eagle Energy Commercial Trust, Eagle Energy US GP LLC, Eagle Energy Inc. and Eagle Energy Acquisitions LP are required to satisfy certain customary affirmative and negative covenants (including financial covenants).The credit facility provides for customary negative covenants which, among other things, limit the Trust from making distributions of cash flow to its unitholders if any default or event of default has occurred and is continuing or would result from such distribution, or if more than 90% of the lesser of the borrowing base or total commitments under the credit facility has been utilized. The credit facility also includes other customary restrictive covenants including limitations on indebtedness, liens, contingent obligations, investments, dispositions, mergers, consolidations, liquidations and dissolutions and a negative pledge. In addition, a minimum current ratio (the ratio of current assets plus the unused commitment under the credit facility to current liabilities excluding any amounts owing under the credit facility) of not less than 1.00 to 1.00, a minimum coverage of interest expenses of not less than 3.00 to 1.00, and a maximum level of debt to earnings before interest, taxes and depreciation of 3.00 to 1.00 must be maintained. Failure to comply with any of these financial covenants, as well as any of the other affirmative and negative covenants, would result in an event of default which, if not cured or waived, would permit acceleration of the indebtedness pursuant to the credit facility.

At March 31, 2011 there were no covenant violations and no amounts outstanding under the $US 8 million borrowing base nor were there any draws during the period covered by these consolidated financial statements. Subsequent to March 31, 2011, the borrowing base was increased as a result of a scheduled evaluation. Refer to note 31.

26. Provision for liabilities and other charges

	Provision for decommissioning costs
Balance at December 31, 2010	$ 217,380
Additions	50,402
Changes in estimates	-
Adjustment for change in risk free discount rate	-
Accretion (unwinding of discount)	2,123
Balance at March 31, 2011	$ 269,905

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 2011 and 2032. 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 4.0%.

Included in the balance at December 31, 2010 is $139,761 of decommissioning liability recorded as part of the Salt Flat acquisition. See "Acquisitions" note 7. The total undiscounted decommissioning liability at March 31, 2011 was $482,289.

27. Trust capital

Authorized

The beneficial interests in the Trust are represented and constituted by one class of units. An unlimited number of common voting trust units may be issued pursuant to the Trust Indenture. Each unit represents an equal, undivided beneficial interest in the net assets of the Trust, and all units rank equally and rateably with all other units. Each unit entitles the holder to one vote at all meetings of unitholders. Unitholders are entitled to receive non-cumulative distributions from the Trust if, as, and when declared by the Trust.

Trust units are redeemable at any time on demand by the holders thereof. Upon receipt of a redemption request by the Trust, the holder is entitled to receive a price per trust unit (the "Market Redemption Price") equal to the lesser of: (i) 90% of the volume weighted average trading price of a unit during the last 10 trading days; and (ii) 100% of the volume weighted average trading price of a unit on the redemption date. The aggregate Market Redemption Price payable by the Trust in respect of any units tendered for redemption during any calendar month shall be satisfied by way of a cash payment on or before the fifth business day after the end of the calendar month following the calendar month in which the units were tendered for redemption. Unitholders are not entitled to receive cash upon the redemption of their units if the total amount payable by the Trust in respect of such units and all other units tendered for redemption in the same month exceeds $100,000. If a unitholder is not entitled to receive cash, the redemption may be satisfied by distributing notes having an aggregate principal amount equal to the aggregate Market Redemption Price of the trust units tendered for redemption. It is anticipated that the redemption right will not be the primary mechanism for unitholders to dispose of their units.

Trust Units Outstanding

	Number of units	Amount $
Balance at December 31, 2010	17,624,081	$ 159,577,493
Trust Unit issuance costs (additional costs)	---	(115,096)
Balance at March 31, 2011	17,624,081	$159,462,397

For the period ended December 31, 2010, the Trust incurred unit issue costs, relating to the initial public offering, of $13,513,334. During the quarter ended March 31, 2011 the Trust recognized an additional $31,280 of unit issue costs associated with the IPO. Additionally, the Trust incurred $38,017 in conjunction with implementing the unit distribution reinvestment program ("DRIP"). The Trust recognized $45,799 of trust unit issuance costs for various financing projects in progress. None of these transactions resulted in the issuance of additional units during the period. In the event that any of these projects do not proceed, the associated cost of the project will be expensed.

Trust Units Issued, but not classified as Outstanding
Refer to note 10 "Unit based payments". The 387,500 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.

28. Cash generated from operations

For the Three Months Ended March 31, 2011	
Loss for the period	$ (1,911,011)
Adjustments for:	
-Depreciation, depletion and amortization	2,894,739
-Unit based compensation	2,774,856
-Unrealized risk management loss	1,414,002
-Finance expense	19,746
	5,192,332
Changes in working capital:	
-Trade and other receivables	(2,908,972)
-Prepaid expenses	(89,021)
-Trade and other payables	1,088,613
	(1,909,380)
Cash generated from operations	3,282,952
Income taxes paid	-
Net cash generated by operating activities	**$ 3,282,952**

Summary of non-cash items

Operating cash flow	
Unit based compensation	$ 2,774,856
Distributions payable-declared not yet paid	1,576,013
Unrealized risk management loss	1,414,002
Investing activities	
Depreciation, depletion, and amortization	$ 2,894,739
Provision for decommissioning costs	50,402
Accretion of decommissioning provision	2,123
Financing activities	
Finance expense-amortization of deferred financing costs	$ 17,623
Distributions accrued-declared not yet paid	(1,576,013)

29. Related party disclosures

The Trust has no party holding voting control.

Key management personnel

The executive officers include the Chief Executive Officer (CEO), the Executive Vice President, Engineering and Geosciences (EVP), and the Chief Financial Officer (CFO).

Intercompany transactions

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

Head office lease in Calgary, Alberta

The Trust sub-leases 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 $8,000. Refer to “Commitments” note 30 regarding operating lease commitments.

No amounts were owing to this related party as at March 31, 2011. For the quarter ended March 31, 2011 administrative expenses included $24,000 for amounts billed from this related party.

30. Commitments

Operating lease commitment - Head office lease in Calgary, Alberta

The term of the sub-lease agreement is 6 months from January 1, 2011 until June 30, 2011. Thereafter, the agreement will automatically roll over on a monthly basis, unless either party serves a 30 day notice of termination. Therefore, the agreement is cancellable at the end of the term if notice is provided. Future minimum lease payments during the six month term of the sub-lease are $48,000, with $24,000 remaining as at March 31, 2011.

Operating lease commitment – Office lease in Houston, Texas
The agreement was entered into on April 1, 2011, and has an approximate 30 month term from April 7, 2011 through September 30, 2013. Future minimum lease payments during the term of the sub-lease approximate $US $338,000. In $CA the future minimum lease payments approximate $328,000 translated at the exchange rate in effect at the balance sheet date of 0.9696 CAD ($CA) = 1.00 USD ($US).

Drilling rig commitment
The Trust, through its joint venture relationship in the Salt Flat Field, entered into a six month drilling rig commitment agreement effective February 3, 2011. The agreement is then cancellable given a 30 day written notice. The daily rig rate is $US 11,500, resulting in future minimum payments during the six month (180 days) term of the agreement of $US 2,070,000, which is 100% of the commitment. The net commitment to the Trust based upon its approximately 80% interest equates to $US 1,656,000, with $US 1,132,000 remaining as at March 31, 2011. In $CA the future minimum lease payments remaining approximate $1,098,000 translated at the exchange rate in effect at the balance sheet date of 0.9696 CAD ($CA) = 1.00 USD ($US).

31. Subsequent events
USA general partner name change
In April 2011, Eagle Energy US GP LLC, the general partner of Eagle Energy Acquisitions LP, officially changed its legal name to Eagle Hydrocarbons LLC.

Operating office lease in Houston, Texas
On April 1, 2011 Eagle Hydrocarbons LLC entered into a sublease agreement for office space in downtown Houston, Texas. Refer to "Commitments" note 30 regarding operating lease commitments.

Increase in Eagle Energy Acquisitions LP borrowing base
Effective May 12, 2011, the borrowing base under the credit facility was increased to $US 15 million. All other terms and conditions, as described in note 25, remain unchanged.