ENTERRA ENERGY TRUST
Form 6-K
November 24, 2004

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 6-K

REPORT OF FOREIGN PRIVATE ISSUER PURSUANT TO RULE 13a-16 OR 15d-16 UNDER THE

SECURITIES ACT OF 1934

For the Month of November 2004

Commission File Number: 000-32115

ENTERRA ENERGY TRUST
(as successor issuer to Enterra Energy Corp.)

(Translation of registrant s name into English)

2600, 500-4th Avenue S.W.
Calgary, Alberta, Canada T2P 2V6

(Address of principal executive offices)

Indicate by check mark whether the registrant files or will file annual reports under cover Form 20-F or Form 40-F.

Form 20-F_x_ Form 40-F___

Indicate by check mark whether the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1):

Yes___ No_x_

Indicate by check mark whether the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7):

Yes___ No_x_

Indicate by check mark whether by furnishing the information contained in this Form, the registrant is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes___ No_x_

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b):

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENTERRA ENERGY TRUST
(Registrant)
By: Enterra Energy Corp.
Administrator of the Trust
By: *<u>/s/ Luc Chartrand</u>*
Luc Chartrand
President and Chief Executive Officer
Date: November 23, 2004

MANAGEMENT S DISCUSSION AND ANALYSIS

The following management s discussion and analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements of Enterra Energy Trust (the Trust) for the period ended September 30, 2004, other financial information included in this quarterly report and with the MD&A and consolidated financial statements contained in the 2003 Annual Report. Additional information relating to the Trust is available on SEDAR at **www.sedar.com**. This MD&A was written as of October 29, 2004. All amounts are stated in Canadian dollars except where otherwise indicated. Natural gas volumes have been converted to a crude oil equivalent using a ratio of 6 mcf to 1 bbl of oil.

Cash flow from operations, expressed before changes in non-cash working capital, is used by the Trust to measure and evaluate operating performance and liquidity. Cash flow from operations does not have any standardized meaning prescribed by Canadian Generally Accepted Accounting Principles (GAAP) and therefore may not be comparable with the calculation of similar measures for other companies.

It is management s view, based on its communications with investors during events like conference calls, webcasts or road shows, that cash flow from operations is most relevant to our investors and unitholders, especially since the Trust s conversion to an oil and gas income trust. Cash flow from operations is extremely relevant to investors because it is the starting point for setting the monthly distribution level.

Cash flow from operations is reconciled to GAAP earnings in a table included in the MD&A.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This interim report includes forward-looking statements. All statements other than statements of historical facts contained in this interim report, including statements regarding our future financial position, business strategy and plans and objectives of management for future operations, are forward-looking statements. The words believe, may, will, estimate, continue, anticipate, intend, should, plan, expect and similar expressions, as they intended to identify forward-looking statements. We have based these forward-looking statements largely on our current expectations and projections about future events and financial trends that we believe may affect our financial condition, results of operations, business strategy and financial needs. These forward-looking statements are subject to a number of risks, uncertainties and assumptions described in Risk Factors and elsewhere in this interim report.

Other sections of this interim report may include additional factors which could adversely affect our business and financial performance. Moreover, we operate in a very competitive and rapidly changing environment. New risk factors emerge from time to time and it is not possible for our management to predict all risk factors, nor can we assess the impact of all factors on our 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 statements.

We undertake no obligation to update publicly or revise any forward-looking statements. You should not rely upon forward-looking statements as predictions of future events or performance. We cannot assure you that the events and circumstances reflected in the forward-looking statements will be achieved or occur. Although we believe that the expectations reflected in the forward-looking statements are reasonable, we cannot guarantee future results, levels of activity, performance or achievements.

OVERVIEW

During Q3, 2004, the Trust s production revenue increased 59% over Q3, 2003, with an increase of 32% over the nine months ended September 30, 2004 compared to the same period in 2003. Cash flow from operations was $13.1 million for Q3, 2004 or $0.55 on a per unit basis and $36.1 million or $1.61 on a per unit basis for the nine months ended September 30, 2004. Production volumes are up 32%, for both the three and nine months ended September 30, 2004. The Trust established its initial monthly distribution level at US$0.10 per unit, with an increase to US$0.11 per unit declared on March to May 2004 production, an increase to US$0.12 per unit declared on June to August 2004 production and an increase to US$0.13 per unit declared on September 2004 production. This was paid on October 15, 2004.

Effective September 29, 2004 the Trust acquired 100% of the issued and outstanding shares of Rocky Mountain Energy Corp., through its subsidiary Rocky Mountain Acquisition Corp. The acquisition was paid for by the issuance of 1,946,576 Trust units, 341,882 Rocky Mountain Acquisition Corp. exchangeable shares and cash of $7,233,746. The acquisition of Rocky Mountain Energy Corp. has no material impact on the financial results for Q3, 2004 due to the transaction close date occurring at the end of the quarter.

SUMMARIZED FINANCIAL AND OPERATIONAL DATA ***(in Thousand s except for volumes and per unit/share amounts)***

	Three Months Sept. 30 2004	**Three Months Sept. 30 2003(2)**	*% Change*	**Nine Months Sept. 30 2004**	**Nine Months Sept. 30 2003(2)**	*% Change*
Exit production rate (boe per day)	7,659	5,330	+ 44%	7,659	5,330	+ 44%
Production Revenue	$25,467	$ 16,012	+ 59%	$ 74,700	$ 56,499	+ 32%
Average production volumes (6 to 1 boe per day)	6,203	4,713	+ 32%	6,534	4,963	+ 32%
Cash flow from operations *(1)*	$13,109	$ 7,599	+ 73%	$ 36,139	$28,988	+ 25%
Cash flow from operations per unit *(1)*	$ 0.55	$ 0.40	+ 38%	$ 1.61	$ 1.57	+ 3%
Net earnings	$ 4,138	$ 962	+330%	$ 11,347	$10,184	+ 11%
Net earnings per unit	$ 0.23	$ 0.05	+240%	$ 0.51	$ 0.55	- 7%
Distributions paid	$10,924	-	n/a	$28,338	-	n/a
Distributions paid per unit	US$ 0.36	-	n/a	US$ 0.99	-	n/a
Percentage of cashflow	83%	-	n/a	78%	-	n/a
Average number of units outstanding *(after giving effect to trust conversion)*	23,676	18,821	+ 26%	22,412	18,521	+ 21%
Average price per bbl of oil (net of hedging loss)	$46.24	$ 37.09	+ 25%	$40.60	$ 41.81	- 3%
Average price per mcf of natural gas	$6.09	$ 6.06	+ 1%	$6.62	$ 6.87	- 4%
Operating costs per boe	$10.42	$ 8.41	+ 24%	$8.65	$ 7.23	+ 20%
General and administrative expenses per boe *(cash portion)*	$1.65	$ 1.79	- 8%	$1.37	$ 1.73	- 21%

(1) Cash flow from operations is a non-GAAP measure. It is management s view that this information is relevant for investors in order to compare Q3, 2004 with Q3, 2003. Cash flow from operations is reconciled to GAAP earnings in the cash flow section of the MD&A.

(2) The 2003 comparative figures have been restated for the adoption of the change in accounting policy relating to asset retirement obligation.

PRODUCTION INCOME

Production income increased by 59% in the three months ended September 30, 2004 from $16.0 million in Q3, 2003 to $25.5 million in Q3, 2004. This is primarily due to a 46% increase in oil volumes and a 25% increase in oil prices in Q3, 2004. Production income was $74.7 million for the nine months ended September 30, 2004 compared to $56.5 million for the nine months ended September 30, 2003, an increase of 32%. This is attributable to oil volumes increasing 43% in this period, offset to a small degree by a 5% decrease in gas volumes. Both oil and gas prices were slightly lower in the nine months ended September 30, 2004 compared to the same period in 2003.

The Trust exited the third quarter of 2004 at a rate of 7,659 boe/day, consisting of 6,175 bbls/day of oil and 8,904 mcf/day of natural gas, for a mix of 81% oil and 19% natural gas. This represents 44 % increase over the 2003 exit rate of 5,330 boe/day.

Production income ***(in Thousand s except for volumes and pricing)***

	Three Months Sept. 30 2004	**Three Months Sept. 30 2003**	*% Change*	**Nine Months Sept. 30 2004**	**Nine Months Sept. 30 2003**	*% Change*
Crude oil and natural gas liquids	$21,912	$11,998	+ 83%	$62,415	43,163	+ 45%
Natural gas	3,555	4,014	+ 21%	12,285	13,336	- 8%
Total production income	$25,467	$16,012	+ 59%	$74,700	$56,499	+ 32%
Volumes						
Average oil production (in bbls/day)	5,146	3,513	+ 46%	5,406	3,778	+ 43%
Average gas production (in mcf/day)	6,343	7,201	- 12%	6,768	7,107	- 5 %
Average total production (in boe/day)	6,203	4,713	+ 32%	6,534	4,963	+ 32 %
Exit oil production (in bbls/day)	6,175	3,941	+ 57%	6,175	3,941	+ 57%
Exit gas production (in mcf/day)	8,904	8,334	+ 7%	8,904	8,334	+ 7 %
Exit total production (in boe/day)	7,659	5,330	+ 44%	7,659	5,330	+ 44%

Commodity Prices received by Enterra

Average price received per bbl of oil	$46.24	$ 37.09	+25%	$40.60	$ 41.81	- 3%
Average price received per mcf of natural gas	$ 6.09	$ 6.06	+ 1%	$ 6.62	$ 6.87	- 4%

PRODUCTION EXPENSES

Production expenses increased by 63% in the three months ended September 30, 2004 compared to the same period in 2003, which is consistent with the 59% increase in production revenue. Production expenses increased by 58% in the nine months ended September 30, 2004 compared to the same period in 2003. The increase is partially due to the increased volumes as well as a result of the higher operating costs associated with the acquired East Central Alberta properties, included in results since February. Enterra s existing properties have an average operating cost of $8.53 per boe while the East Central Alberta properties have an average operating cost of $16.97 per boe.

Production expenses ***(in Thousand s except for percentages and per boe amounts)***

	Three Months Sept. 30 2004	**Three Months Sept. 30 2003**	*% Change*	**Nine Months Sept. 30 2004**	**Nine Months Sept. 30 2003**	*% Change*
Production expenses	$5,949	$ 3,648	+ 63%	$15,486	$9,797	+ 58%
As a percentage of production revenue	23%	23%	0%	21%	17%	+ 24%
Production expenses per boe	$10.42	$ 8.41	+ 24%	$8.65	$ 7.23	+ 20%

ROYALTIES

Royalties, which include Crown, freehold and overriding royalties, increased by 41% in Q3, 2004 compared to Q3, 2003 and by 21% in the nine months ended September 30, 2004 compared to the same period in 2003. The increase is the result of the increased oil production and oil prices in 2004 offset somewhat by the lower royalty rates on the East Central Alberta properties.

Royalties ***(in Thousand s except for percentages and per boe amounts)***

	Three Months Sept. 30 2004	**Three Months Sept. 30 2003**	*% Change*	**Nine Months Sept. 30 2004**	**Nine Months Sept. 30 2003**	*% Change*
Royalties, net of Alberta Royalty Tax Credit	$4,924	$ 3,500	+ 41%	$16,569	$13,740	+ 21%
As a percentage of production revenue	19%	22%	- 14%	22%	24%	- 8%
Royalties per boe	$ 8.63	$ 8.07	+ 7%	$ 9.25	$ 10.14	- 9%

GENERAL AND ADMINISTRATIVE EXPENSES

The cash portion of general and administrative expenses is 4% and 3% of production revenue for the three months and nine months ended September 30, 2004 respectively. Although this represents an increase of 21% in Q3, 2004 compared to Q3, 2003 and an increase of 5% in the nine months ended September 30, 2004 compared to the same period in 2003, the G&A per boe has decreased by 8% and 21% respectively for the three and nine months ended September 30, 2004. This represents a 20% and 25% decrease in G&A as a percentage of revenue for the three and nine month periods ended September 30, 2004 respectively. The non-cash portion of general and administrative expenses in 2004 relate to the value assigned to 920,000 options granted to employees and directors.

General and administrative expenses ***(in Thousand s except for percentages and per boe amounts)***

	Three Months Sept. 30	**Three Months Sept. 30**	*% Change*	**Nine Months Sept. 30**	**Nine Months Sept. 30**	*% Change*

	2004	2003		2004	2003	
General and administrative expenses cash portion	$ 944	$ 778	+ 21%	$2,455	$ 2,343	+ 5%
General and administrative expenses non cash portion	$ 243	$ -	n/a	$ 684	$ -	n/a
As a percentage of production revenue (cash portion)	4%	5%	- 20%	3%	4%	- 25%
General and administrative expenses per boe (cash portion)	$ 1.65	$ 1.79	- 8%	$ 1.37	$ 1.73	- 21%

INTEREST EXPENSE

Interest expense increased by 34% in Q3, 2004 compared to Q3, 2003 and 29% in the nine months ended September 30, 2004 compared to the same period in 2003. The 2004 increase is due to the higher average outstanding loan balances than during the same periods in 2003.

Interest expense ***(in Thousand s except for percentages and per boe amounts)***

	Three Months Sept. 30 2004	**Three Months Sept. 30 2003**	*% Change*	**Nine Months Sept. 30 2004**	**Nine Months Sept. 30 2003**	*% Change*
Long-term debt, including bank debt at end of period	$43,034	$28,116	+ 53%	$43,034	$28,116	+ 53%
Interest expense	$ 510	$ 379	+ 34%	$ 1,731	$ 1,339	+ 29%
As a percentage of production revenue	2%	2%	0%	2%	2%	0%
Interest expense per boe	$ 0.89	$ 0.87	+ 2%	$ 0.97	$ 0.99	- 2%

DEPLETION AND DEPRECIATION

Depletion and depreciation expense increased by 29% and 39% in the three and nine months ended Q3, 2004 compared to Q3, 2003, primarily due to the higher depletable base with the addition of the East Central Alberta properties.

Depletion and depreciation expense ***(in Thousand s except for percentages and per boe amounts)***

	Three Months Sept. 30 2004	**Three Months Sept. 30 2003 (restated)**	*% Change*	**Nine Months Sept. 30 2004**	**Nine Months Sept. 30 2003 (restated)**	*% Change*
Depletion and depreciation expense	$7,424	$5,766	+ 29%	$23,787	$17,096	+ 39%
As a percentage of production revenue	29%	36%	- 19%	32%	30%	+ 7%
Depletion and depreciation expense per boe	$13.01	$13.30	- 2%	$13.29	$ 12.62	+ 5%

INCOME AND CAPITAL TAXES

The Trust recorded an income tax provision of $0.4 million in the nine months ended September 30, 2004 compared with a provision of $−−1.7 million in the same period in 2003. The decrease in income tax is primarily due to larger interest payments from Enterra to the Trust, which are deductible for Enterra (taxable to the unitholder by way of distributions) in calculating future taxes, together with a decrease in a substantively enacted Alberta income tax rate by 1% and the tax impact of adopting the new accounting policies.

Income tax expense ***(in Thousand s except for percentages)***

	Three	**Three**		**Nine**	**Nine**

	Months Sept. 30 2004	Months Sept. 30 2003 (restated)	% Change	Months Sept. 30 2004	Months Sept. 30 2003 (restated)	% Change
Income tax expense	$1,311	$971	+ 35%	$359	$1,747	- 79%
Combined federal and provincial income tax rate	39.12%	42.12%	- 7%	39.12%	42.12%	- 7%

EARNINGS

The Trust s net earnings for Q3, 2004 are 330% higher than Q3, 2003. The 59% higher revenue as a result of higher oil volumes was offset by:

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higher depletion expense as a result of the increased production and the higher depletable base.

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higher operating costs related to the increased volumes and the higher unit costs at the East Central Alberta properties.

.

higher royalties resulting from the increased production.

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higher interest expense attributable to higher debt levels

Earnings for the nine months ended September 30, 2004 were $11.3 million compared to $10.2 million in the same period in 2003, an increase of 11%. Production income increased by 32% in the nine month period ended September 30, 2004 compared to the same period ending September 30, 2003 partially offset by the increases in operating costs, royalties, depletion expense, realized hedging losses and interest expense.

Earnings ***(in Thousand s except for per unit/ share amounts)***

	Three Months Sept. 30 2004	**Three Months Sept. 30 2003 (restated)**	*% Change*	**Nine Months Sept. 30 2004**	**Nine Months Sept. 30 2003 (restated)**	*% Change*
Net earnings	**$4,138**	$962	+ 330%	**$11,347**	$10,184	+ 11%
Net earnings as a percentage of revenue	16%	6%	+ 166%	15%	18%	- 16%
Net earnings on a per boe basis	$7.25	$2.22	+ 227%	$6.34	$7.52	- 16%
Per unit information						
Net earnings per unit	$0.17	$0.05	+ 240%	$0.51	$0.55	- 7%
Average number of units outstanding	23,676	18,821	+ 26%	22,412	18,521	+ 21%

CASH FLOW FROM OPERATIONS

Cash flow from operations of $13.1 million increased by $5.5 million or 73% in Q3, 2004 compared to Q3, 2003. This is attributable to higher oil prices and oil production volumes partially offset by higher operating costs on newly acquired properties as well as higher royalties and general and administrative expense.

The changes on a per unit basis showed similar results with an increase to $0.55 per unit from $0.40 per unit or 38% in Q3 of 2004 compared to Q3 of 2003. The cash flow per unit for the nine months ended September 30, 2004 was $1.61 per unit compared to $1.57 per unit for the same period in 2003.

As mentioned earlier, it is management s view that cash flow from operations is a very useful measure of performance. Cash flow from operations is the key factor in setting the Trust s monthly distribution rate. Cash flow from operations is also a good benchmark when comparing results from year to year or quarter to quarter because it excludes one-time non-recurring events, which may otherwise distort the financial results. Cash flow from operations is a non-GAAP measure, reconciled with GAAP net earnings in the table below:

Cash flow from operations ***(in Thousand s except for per unit/share amounts)***

	Three Months Sept. 30 2004	Three Months Sept. 30 2003 (restated)	*% Change*	**Nine Months Sept.30 2004**	Nine Months Sept. 30 2003 (restated)	*% Change*
Net earnings	**$4,138**	$962	+ 330%	**$11,347**	$10,184	+ 11%
Add back depletion and depreciation	7,424	5,766		23,788	17,096	
Add back amortization of deferred financing charges	24	9		51	289	
Add back (deduct) future income taxes	1,281	940		269	1,656	
Deduct amortization of deferred gain	-	(78)		-	(237)	
Add back non-cash expense related to value of options	243	-		684	-	
Cash flow from operations	**$13,110**	$7,599	+ 73%	**$36,139**	$28,988	+ 25%
Cash flow from operations as a percentage of revenue	51%	47%	+ 9%	48%	51%	- 6%
Cash flow from operations on a per boe basis	$22.97	$17.52	+ 231%	$20.18	$21.39	- 6%
Per unit information						
Cash flow from operations per unit	$0.55	$0.40	+ 38%	$1.61	$1.57	+ 3%
Average number of units outstanding	23,676	18,821	+ 26%	22,412	18,521	+21%

CAPITAL EXPENDITURES

Capital expenditures for the nine months ended September 30, 2004 were $76.5 million compared to $37.4 million in the nine months ended September 30, 2003. Proceeds on disposal were $0.4 million and $1.2 million for the three and nine months ended September 30, 2004 respectively compared to $0.4 million and $16.0 million for the three and nine month periods ending September 30, 2003.

The 2004 capital expenditures of $29.9 relate to the acquisition of the East Central Alberta properties, which was completed on January 30, 2004 ($19.8 million), as well as completion of the drilling programs at Clair and Sylvan Lake.

In addition, on September 29, 2004, the Trust acquired 100% of Rocky Mountain Energy Corp., a publicly traded oil and gas exploration, development and production company through the issue of cash, trust units and exchangeable shares of the Trust s newly formed subsidiary Rocky Mountain Acquisition Corp, for a total purchase price of $48.2 million.

There were minimal disposals in 2004 compared to disposals of $16.0 million for the nine months ended September 30, 2003.

CASH DISTRIBUTIONS

The Trust paid distributions of US$0.10 per unit for the production month of December 2003 and for the first two production months of 2004. The Trust paid distributions of US$0.11 per unit for the three production months ending May 2004 and US$0.12 pr unit for the three production months ending August 2004. The distribution for the month of September 2004 was raised to US$0.13 per unit. Cash distributions are paid on the 15th of the following month (e.g. the September distribution was paid on October 15).

Total distributions paid out during the three and nine months ended September 30, 2004 were $10.9 million and $28.3 million respectively, representing 83% and 78% of the Trust s cash flow for these periods.

Cash Distributions ***(in Thousand s except for per unit amounts)***

	Q1 2004	Q2 2004	Q3 2004	Total
Distributions paid	$ 7,828	$ 9,586	**$10,924**	**$28,338**
			US$0.36	**US$0.99**
Distributions paid per unit	US$0.30	US$0.33		
Weighted average units outstanding	21,528	22,019	**23,676**	**22,412**
Percentage of cashflow	82%	71%	**83%**	**78%**

LIQUIDITY AND CAPITAL RESOURCES

The Trust s bank debt at September 30, 2004 was $39.5 million (December 31, 2003 - $34 million). In both periods these funds have been used to acquire capital assets and support ongoing operations. At September 30, 2004 the Trust s bank facility consisted of a demand production facilities totaling $41.0 million and a subordinated debt facility of $7.0 million (December 31, 2003 - $34.7 million). Interest on amounts drawn on the demand credit facilities is based on the bank s prime rate plus 0.40% and interest on the subordinated debt facility is based on the bank s prime rate plus 2%. Security is provided by a first charge over all of the Trust s assets. The balance is repayable on demand. While the production facility is due on demand, the Trust is not subject to scheduled repayments. However, the amount available under the subordinated debt facility will decrease by $1.0 million on October 31, 2004 and for each month until April 30, 2005, leaving a total credit facility balance of $41.0 million.

On January 16, 2004 the Trust entered into a financing agreement whereby the Trust would issue 1,650,000 Trust Units at a price of US$10.00 per unit for gross proceeds of US$ 16,500,000. The financing closed and payment was received on June 29, 2004 upon registration of the units. These funds were applied towards the financing for the East Central Alberta property acquisition described below.

On January 30, 2004 the Trust closed an acquisition of properties in East Central Alberta for $19.8 million.

On February 20, 2004 the Trust completed a private placement of 1,049,400 Trust Units at a price of US$11.25 per unit for gross proceeds of US$11,805,750 (US$10,265,463 net of financing costs). These funds were used for drilling projects, which Enterra began prior to its conversion to a trust.

On September 29, 2004, the Trust acquired 100% of the outstanding shares of Rocky Mountain Energy Corp., an oil and gas exploration and development company, by the issuance of $34.4 million of trust units, $6.1 million of Rocky Mountain Acquisition Corp. exchangeable shares and $7.2 million cash for a total purchase price of $48.2 million including transaction costs of $0.5 million.

Capital expenditures, excluding acquisitions, are expected to be approximately $5-$10 million in 2004 because the Trust, as an income trust, will be distributing approximately 80% of its cash flow through its monthly distributions. The Trust s strategy for growth in 2004 will be focused on property acquisitions which will be funded with a combination of additional debt and equity. Based on its success to date, management feels confident in its ability to raise new equity for accretive assets and believes it has sufficient capital resources to meet its obligations and continue to achieve positive financial results.

Enterra has approximately $83.4 million in tax pools available at September 30, 2004. (September 30, 2003 - $68.1 million).

The Trust has a number of forward contracts that were put in place during the year in order to minimize the volatility in crude oil pricing. Below is a summary of the Trust s hedging operations in 2004:

Hedging summary

Description	**Quantity**	**Pricing**
Oil contracts from July 1/2004 to December 31/2004	1,000 bbls of oil/day	C$40.50 per barrel

At September 30, 2004, the Trust had a total of 25,125,507 Trust units (December 31, 2003 18,955,960), 501,159 Enterra Energy Corp. exchangeable shares (December 31, 2003 1,995,596) and 341,882 Rocky Mountain Acquisition Corp. exchangeable shares (December 31, 2003 nil) outstanding. As of October 29, 2004, 92,016 additional trust units were issued in exchange for Rocky Mountain Acquisition Corp. exchangeable shares.

SUMMARY OF QUARTER RESULTS

Quarterly Performance ***(in Thousand s except for per unit/share amounts)***

	Q3-2004	**Q2-2004**	**Q1-2004**	**Q4-2003**	**Q3-2003**	**Q2-2003**	**Q1-2003**	**Q4-2002**
Revenue	$25,467	$27,585	$21,648	$15,598	$16,012	$18,484	$22,002	$10,060
Net earnings	$ 4,138	$ 4,647	$ 2,562	$(5,104)	$ 962	$ 5,037	$ 4,186	$ 715
Net earnings per unit	$ 0.23	$ 0.21	$ 0.12	$ (0.28)	$ 0.05	$ 0.27	$ 0.23	$ 0.04
Net earnings per unit - diluted	$ 0.23	$ 0.21	$ 0.12	$ (0.25)	$ 0.05	$ 0.25	$ 0.21	$ 0.03
Weighted average units outstanding	23,676	22,019	21,528	20,205	18,821	18,411	18,365	18,337

CRITICAL ACCOUNTING POLICIES

The Trust follows the full cost method of accounting for oil and natural gas properties and equipment whereby we capitalize all costs relating to its acquisition of, exploration for and development of oil and natural gas reserves. The Trust s consolidated financial condition and results of operations are sensitive to, and may be adversely affected by, a number of subjective or complex judgments relating to methods, assumptions or estimates required under the full cost method of accounting concerning the effect of matters that are inherently uncertain. For example:

(i)

Capitalized costs under the full cost method are generally depleted and depreciated using the unit-of-production method, based on estimated proved oil and gas reserves as determined by independent engineers. In addition, capital costs are also restricted from exceeding the ceiling test under Accounting Guideline No. 16 as more fully described below. Should this comparison indicate an excess carrying value, a write-down would be recorded. To economically evaluate the Trust s proved oil and natural gas reserves, these independent engineers must necessarily make a number of assumptions, estimates and judgments that they believe to be reasonable based upon their expertise and professional and CICA and SEC guidelines. Were the independent engineers to use differing assumptions, estimates and judgments, then the Trust s consolidated financial condition and results of operations would be affected. For example, the Trust would have lower net earnings (or higher net losses) in the event the revised assumptions, estimates and judgments resulted in lower reserve estimates, since our depletion and depreciation rate would then be higher and it might also result in a write-down under the ceiling test. Similarly, the Trust would have higher net earnings (or lower net losses) in the event the revised assumptions, estimates and judgments resulted in higher reserve estimates.

(ii)

The Trust s management also periodically assesses the carrying values of unproved properties to ascertain whether any impairment in value has occurred. This assessment typically includes a determination of the anticipated future net cash flows based upon reserve potential and independent appraisal where warranted. Impairment is recorded if this assessment indicates the future potential net cash flows are less than the capitalized costs. Were the Trust s management to use differing assumptions, estimates and judgments, then the Trust s consolidated financial condition and results of operations would be affected. For example, the Trust would have lower net profits (or higher net losses) in the event the revised assumptions, estimates and judgments resulted in increased impairment expense.

(iii)

Effective January 1, 2004, the Trust retroactively adopted CICA handbook Section 3110 Asset Retirement Obligations . The new recommendations require the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion expense which is included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset.

(iv)

In January 1, 2004, the Trust adopted CICA Accounting Guideline 13, Hedging Relationships (AcG-13). AcG-13 establishes certain conditions for when hedge accounting may be applied and addresses the identification, designation, documentation and effectiveness of hedging transactions. Where hedge accounting does not apply, any changes in the mark to market values of the option contracts relating to a financial period can either reduce or increase net income and net income per trust unit for that period. The Trust has elected not to apply hedge accounting to any of its financial instruments. Effective January 1, 2004, the Trust has recorded the fair value of financial instruments as a deferred financial loss of $958,359 and a deferred financial liability of $958,359 on the balance sheet. At June 30, 2004, the deferred financial loss was amortized to a balance of nil through revenues and the deferred liability was decreased to zero.

(v)

Effective January 1, 2004, the Trust adopted the fair value method of accounting for options on a retroactive basis, without prior period restatement. In the past, the Trust measured stock option compensation cost based on the intrinsic value of the award at the date of issuance. As the exercise price and the market price were the same at the grant date, no compensation cost was recognized on any option issuance. In 2003, the Trust disclosed pro forma net income and earnings per share as if compensation cost for the Trust's unit-based compensation plan had been determined based on the fair value at the grant date for awards made under the plan subsequent to January 1, 2002.

As a result of the adoption of this policy, the Trust has recorded a charge to retained earnings of

$646,031 as at January 1, 2004 to reflect the accumulated stock option expense awards made under the plan subsequent to January 1, 2002. The estimated fair value of the options issued in 2003 and 2002 has been determined using a Black-Scholes option-pricing model.

(vi)

Effective January 1, 2004, the Trust adopted Accounting Guideline 16, Oil and Gas Accounting Full Cost which replaces AcG-5 Full Cost Accounting in the Oil and Gas industry. AcG-16 modifies how the ceiling test is performed and is consistent with CICA Section 3063, Impairment of Long-lived Assets. The new guideline modifies the ceiling test to be performed in two stages. The first stage requires the carrying value to be tested for recoverability using undiscounted future cash flows from proved reserves using forward indexed prices. If the carrying value is not recoverable, the second stage, which is based on the calculation of discounted future cash flows from proved plus probable reserves, will determine the impairment to the fair value of the asset. There is no write down of the Trust s property, plant and equipment under either the old or the new method as of January 1, 2004 or September 30, 2004.

ENTERRA ENERGY TRUST

Consolidated Balance Sheets

(Expressed in Canadian dollars)

(Unaudited)

	September 30 2004	December 31 2003 (as restated) Note 1
Assets		
Current assets		
Cash	**$ 37,557**	$ 65,643
Accounts receivable	**14,664,126**	8,742,690
Deposit on land purchase	**-**	2,015,000
Prepaid expenses and deposits	**443,608**	461,727
	15,145,291	11,285,060
Deferred financing charges	**205,395**	123,208
Capital assets	**163,401,218**	105,253,166
Goodwill (note 2)	**16,738,000**	-
	$195,489,904	$116,661,434
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 9,872,358**	$ 12,208,390
Distributions payable to unitholders	**4,104,452**	2,451,402
Income taxes payable	**186,466**	120,000
Bank indebtedness (note 3)	**39,450,000**	33,959,733
Current portion of long-term debt	**796,346**	782,930
	54,409,622	49,522,455
Asset retirement obligation (note 1(b))	**4,036,455**	2,188,052
Future income tax liability (note 4)	**27,299,327**	13,936,327
Long-term debt	**2,787,954**	3,385,618

	88,533,358	69,032,452
Unitholders Equity		
Unitholders capital (note 5(a))	**107,317,878**	32,838,163
Exchangeable shares (note 5(b))	**6,911,050**	3,457,050
Contributed surplus (note 1(d))	**684,024**	-
Accumulated earnings	**24,485,902**	13,785,171
Accumulated distributions	**(32,442,308)**	(2,451,402)
	106,956,546	47,628,982
Forward contracts (note 6)		
	$195,489,904	$116,661,434

Approved on behalf of the Board:

Reg Greenslade	Bill Sliney
Director	Director

See accompanying notes to consolidated financial statements

ENTERRA ENERGY TRUST

Consolidated Statements of Earnings and Accumulated Earnings

Three and Nine Months Ended September 30

(Expressed in Canadian dollars)

(Unaudited)

	Three Months September 30 2004	Three Months September 30 2003 (as restated)	**Nine Months September 30 2004**	Nine Months September 30 2003 (as restated)
Revenue				
Oil and gas	**$25,466,547**	$16,012,230	**$74,699,847**	$56,499,089

Royalties, net of ARTC	**(4,923,877)**	(3,499,607)	**(16,568,621)**	(13,740,445)
	20,542,670	12,512,623	**58,131,226**	42,758,644
Expenses				
Production	**5,948,936**	3,648,211	**15,485,740**	9,796,742
General and administrative	**1,187,049**	778,156	**3,139,920**	2,342,937
Depletion, depreciation and accretion	**7,423,903**	5,766,067	**23,787,498**	17,095,878
Amortization of deferred financing charges	**23,660**	8,800	**51,472**	253,335
Interest	**509,787**	379,131	**1,730,865**	1,339,026
Financial derivative loss (note 1(c))	**-**	-	**2,229,969**	-
	15,093,335	10,580,365	**46,425,464**	30,827,918
Earnings before income taxes	**5,449,335**	1,932,258	**11,705,762**	11,930,726
Income taxes:				
Current	**30,000**	30,000	**90,000**	90,000
Future (note 4)	**1,281,200**	940,667	**269,000**	1,656,603
	1,311,200	970,667	**359,000**	1,746,603
Net earnings	**4,138,135**	961,591	**11,346,762**	10,184,123
Accumulated earnings, beginning of period	**20,347,767**	17,906,694	**13,937,025**	8,933,223
Changes in accounting policy related to:				
Asset retirement obligation (note 1(b))	**-**	-	**(151,854)**	(249,061)
Unit based compensation (note 1(d))	**-**	-	**(646,031)**	-
Accumulated earnings as restated, beginning of period	**20,347,767**	17,906,694	**13,139,140**	8,684,162
Accumulated earnings, end of period	**$24,485,902**	$18,868,285	**$24,485,902**	$18,868,285
Earnings per unit/share:				
Basic	**$ 0.17**	$ 0.05	**$ 0.51**	$ 0.55
Diluted	**$ 0.17**	$ 0.05	**$ 0.50**	$ 0.51

See accompanying notes to consolidated financial statements

ENTERRA ENERGY TRUST
Consolidated Statements of Cash Flows
Three and Nine Months Ended September 30
(Expressed in Canadian dollars)

(Unaudited)

	Three Months September 30 2004	Three Months September 30 2003 (as restated)	**Nine Months September 30 2004**	Nine Months September 30 2003 (as restated)
Cash provided by (used in):				
Operations				
Net earnings	**$4,138,135**	$961,591	**$11,346,762**	$10,184,123
Add non-cash items:				
Depletion, depreciation and accretion	**7,423,903**	5,766,067	**23,787,498**	17,095,878
Future income taxes	**1,281,200**	940,667	**269,000**	1,656,603
Amortization of deferred gain	**-**	(78,474)	**-**	(237,463)
Amortization of deferred financing charges	**23,660**	8,800	**51,472**	289,026
Unit based compensation (note 1(d))	**242,974**	-	**684,024**	-
	13,109,872	7,598,651	**36,138,756**	28,988,167
Net change in non-cash working capital items:				
Accounts receivable	**(529,885)**	1,213,456	**(2,251,459)**	(1,277,588)
Prepaid expenses and deposits	**(20,329)**	(34,358)	**77,181**	172,138
Accounts payable and accrued liabilities	**497,442**	8,234,075	**(5,797, 400)**	(6,021,565)
Future abandonment and site restoration costs	**(3,600)**	(1,890)	**(3,600)**	(4,559)
Income taxes payable	**30,000**	30,000	**(10,000)**	80,147
	13,083,500	17,039,934	**28,153,478**	21,936,740

Financing				
Bank indebtedness	**2,919,937**	4,250,000	**(2,174,796)**	(639,140)
Long-term debt	**(138,649)**	(205,433)	**(584,248)**	(602,737)
Deferred financing charges	**54,887**	(59,213)	**(133,659)**	(136,993)
Issue of units/shares, net of issue costs	**-**	1,071,818	**36,838,468**	1,337,370
Cash distributions	**(10,924,207)**	-	**(28,337,855)**	-
Redemption of preferred shares	**-**	(575,685)	**-**	(636,690)
	(8,088,032)	4,481,487	**5,607,910**	(678,190)
Investing				
Capital assets additions	**(5,885,873)**	(21,913,686)	**(29,794,184)**	(37,357,456)
Acquisition of Rocky Mountain Energy Corp. (note 2)	**(7,217,476)**		**(7,217,476)**	
Proceeds on disposal of property and equipment	**430,566**	404,636	**1,207,186**	16,034,992
Deposit on land purchase	**-**	-	**2,015,000**	-
	(12,672,783)	(21,509,050)	**(33,789,474)**	(21,322,464)
Net increase (decrease) in cash	**(7,677,315)**	12,371	**(28,086)**	(63,914)
Cash, beginning of period	**7,714,872**	31,732	**65,643**	108,017
Cash, end of period	**$37,557**	$44,103	**$37,557**	$44,103

During the three and nine months ended September 30, 2004, the Trust paid respectively $457,425 and $1,475,801 (2003 - $283,925 and $1,042,500) of interest on long-term debt and taxes of $nil and $100,000 respectively (2003 - $nil in both periods). During the three and nine months ended September 30, 2004, the Trust capitalized general and administrative expenses respectively of $247,000 and $849,300 (2003 - $404,500 and $1,347,900).

See accompanying notes to consolidated financial statements

ENTERRA ENERGY TRUST

Notes to Consolidated Financial Statements

For the Three and Nine Months Ended September 30, 2004 and 2003

(Unaudited)

The interim consolidated financial statements of Enterra Energy Trust (the Trust) have been prepared by management in accordance with Canadian generally accepted accounting principles. The interim consolidated financial statements have been prepared following the same accounting policies and methods used in preparing the consolidated financial statements for the fiscal year ended December 31, 2003, except as described in note 1, and should be read in conjunction with those consolidated financial statements. The interim consolidated financial statements contain disclosures, which are supplemental to the Trust s annual consolidated financial statements. Certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements have been condensed or omitted. Certain comparative amounts have been reclassified to conform to the current presentation.

1. Changes in Accounting Policies

(a) Full Cost Accounting

Effective January 1, 2004, the Trust adopted Accounting Guideline 16, Oil and Gas Accounting Full Cost which replaces AcG-5 Full Cost Accounting in the Oil and Gas industry. AcG-16 modifies how the ceiling test is performed and is consistent with CICA Section 3063, Impairment of Long-lived Assets. The new guideline modifies the ceiling test to be performed in two stages. The first stage requires the carrying value to be tested for recoverability using undiscounted future cash flows from proved reserves using forward indexed prices. If the carrying value is not recoverable, the second stage, which is based on the calculation of discounted future cash flows from proved plus probable reserves, will determine the impairment to the fair value of the asset. There is no write down of the Trust s property, plant and equipment as of January 1, 2004 or September 30, 2004. The base average price forecasts used by the individual consultants evaluating the existing reserves and purchased reserves as at January 1, 2004 are adjusted for quality, transportation and heat content and are outlined in the following table.

	2004	2005	2006	2007	2008	Thereafter
WTI ($US/bbl)	29.00	26.50	25.50	25.00	25.00	25.50-33.60
WTI ($US/bbl)	29.00	25.50	24.25	24.00	23.25	23.25-21.50
AECO Spot Price ($Cdn/mcf)	5.50	5.19	4.87	4.68	4.53	4.57-5.95
AECO Spot Price ($Cdn/mcf)	5.85	5.15	5.00	5.00	5.00	5.00*

* increasing 1.5%/year after 2014.

(b) Asset Retirement Obligations

Effective January 1, 2004, the Trust retroactively adopted CICA handbook Section 3110 Asset Retirement Obligations . The new recommendations require the recognition of the fair value of obligations associated with the retirement of long-lived assets to be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion expense which are included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset.

At September 30, 2004, the Trust estimated the asset retirement obligation to be $4.0 million (December 31, 2003 - $2.2 million), based on a total future liability of $14.0 (December 31, 2003 - $4.2 million). These obligations will be settled at the end of the useful lives of the underlying assets, which currently extend up to 30 years into the future. This amount has been calculated using an inflation rate of 2% and discounted using a weighted average credit-adjusted risk-free interest rate of 5.9%.

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The following table summarizes the changes resulting from this restatement. The adjustments to the statement of earnings for the three months ended September 30, 2004 are immaterial.

	Balance as Previously Reported	Adjustments	Balance as Restated
Balance Sheet as at December 31, 2003			
Capital assets	$104,821,285	431,881	$105,253,166
Asset retirement obligation	$ 1,529,244	658,808	$ 2,188,052
Accumulated earnings	$ 13,937,025	(151,854)	$ 13,785,171

Future income tax liability	$ 14,011,400	(75,073)	$ 13,936,327

	Balance as Previously Reported	Adjustments	Balance as Restated
Statement of Earnings for nine months ended September 30, 2003			
Depletion, depreciation and accretion	$ 17,211,000	(115,122)	$17,095,878
Future income tax expense	$ 1,617,899	38,704	$ 1,656,603
Net earnings	$ 10,107,705	76,418	$10,184,123

The following table reconciles the asset retirement obligation associated with the retirement of oil and gas properties.

Asset Retirement Obligation at January 1, 2003 (as restated)	**$3,090,389**
Obligation incurred	**744,422**
Abandonment expenditures	**(5,414)**
Property disposition	**(1,753,446)**
Accretion expense	**112,101**
Asset Retirement Obligation at December 31, 2003 (as restated)	**$2,188,052**
Obligation incurred	**1,192,558**
Abandonment expenditures	**(3,600)**
Corporate acquisition	**679,764**
Property disposition	**(120,817)**
Accretion expense	**100,498**
Asset Retirement Obligation at September 30, 2004	**$4,036,455**

(c) Financial Instruments

On January 1, 2004, the Trust adopted CICA Accounting Guideline 13, Hedging Relationships (AcG-13). AcG-13 establishes certain conditions for when hedge accounting may be applied and addresses the identification, designation, documentation and effectiveness of hedging transactions. Where hedge accounting does not apply, any changes in the mark to market values of the forward contracts relating to a financial period can either reduce or increase net earnings and net earnings per unit for that period. The Trust has elected not to apply hedge accounting to any of its financial instruments. Effective January 1, 2004, the Trust has recorded the fair value of financial instruments as a deferred financial loss of $958,359 and a deferred financial liability of $958,359 on the balance sheet. As at September 30, 2004, the deferred financial loss of $958,359 was amortized through revenues and the deferred financial liability was decreased to zero, as the Trust no longer has any hedges that meet the definition of a financial instrument given that all hedges are now physical contracts.

The following table reflects the changes in the financial derivative liability and deferred financial derivative loss accounts during the period.

Financial Derivative Liability at January 1, 2004	**$ 958,359**
Financial instruments settled	**(3,188,328)**
Mark to market realized loss	**2,229,969**
Financial Derivative Liability at September 30, 2004	**$ nil**

Deferred Financial Derivative Loss at January 1, 2004	**$ 958,359**
Amortization of deferred financial loss	**(958,359)**
Deferred Financial Derivative Loss at September 30, 2004	**$ nil**

(d) Unit-based Compensation

Effective January 1, 2004, the Trust adopted the fair value method of accounting for options on a retroactive basis, without prior period restatement. In the past, the Trust measured stock option compensation cost based on the intrinsic value of the award at the date of issuance. As the exercise price and the market price were the same at the grant date, no compensation cost was recognized on any option issuance. In 2003, the Trust disclosed pro forma net earnings and earnings per unit as if compensation cost for the Trust's unit-based compensation plan had been determined based on the fair value at the grant date for awards made under the plan subsequent to January 1, 2002.

As a result of the adoption of this policy, the Trust has recorded a charge to accumulated earnings of $646,031 as at January 1, 2004 to reflect the accumulated unit option expense awards made under the plan subsequent to January 1, 2002. The estimated fair value of the options issued in 2003 and 2002 has been determined using a Black-Scholes option pricing model.

In 2003, had the Trust recorded compensation cost for the Trust's unit-based compensation plan based on the fair value at the grant date for awards made under the plan subsequent to January 1, 2002, consistent with the fair value method of accounting for stock-based compensation, the Trust's net earnings and earnings per share would have been as follows:

	2003 Three Months September 30 (as restated)	2003 Nine Months September 30 (as restated)
Net earnings (in 000 s)		
As reported	$962	$10,184
Less fair value of stock options to employees	(79)	(223)
Pro Forma	$883	$ 9,961
Earnings per common share ($/share)		
Basic as Reported	$0.05	$0.55
Pro Forma	$0.05	$0.54
Diluted as Reported	$0.05	$0.51
Pro Forma	$0.04	$0.50

In 2004, 920,000 options were issued to employees at a fair value of $3.47 per unit as determined by the Black-Scholes model resulting in compensation expense for the three and nine months ended September 30, 2004 of $242,974 and $684,024 respectively with a corresponding credit to contributed surplus. Assumptions used in the 2004 Black-Scholes model were a risk free interest rate of 3.8%, a distribution yield of 9%, a 5 year life and volatility of 21%. Assumptions in the 2003 Black-Scholes model applied before the conversion to a Trust were a risk free interest rate of 5.0%, a distribution yield of 0%, a 5 year life and volatility of 50%.

e) Goodwill

Under the terms of section 1581 of the CICA handbook, goodwill must be recorded upon a corporate acquisition when the total purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired company. The goodwill balance is not amortized but instead is assessed for impairment each reporting period. Impairment is determined on the fair value of the reporting entity (the consolidated trust) compared to the book value of the reporting entity. Any impairment will be charged to earnings in the period in which the fair value of the reporting entity is below the book value.

This accounting policy was adopted as a result of the acquisition of Rocky Mountain Energy Corp.

2.

Business combination

Effective September 29, 2004 the Trust acquired 100% of the issued and outstanding shares of Rocky Mountain Energy Corp., through a subsidiary Rocky Mountain Acquisition Corp. (RMAC). Details of the acquisition based on the preliminary purchase price allocation are as follows:

Assets acquired:	
Current assets, excluding cash	$ 3,729,040
Property and equipment	52,176,313
Goodwill	16,738,000
	72,643,353
Liabilities assumed:	
Current liabilities	3,037,834
Bank indebtedness	7,665,063
Asset retirement obligations	679,764

Future income tax liability	13,094,000
	24,476,661
Net non-cash assets acquired	48,166,692
Cash acquired	16,270
	$48,182,962
Consideration:	
Cash	$ 7,233,746
RMAC exchangeable shares (341,882 issued)	6,117,569
Trust Units (1,946,576 issued)	34,831,647
Transaction Costs	500,000
	$48,182,962

The value assigned to each Enterra trust unit was Cdn$17.68 based on their 10 day weighted average trading price on Nasdaq immediately prior to and after the measurement date.

3.

Bank indebtedness

Bank indebtedness represents the outstanding balance under lines of credit totaling $48,000,000 (2003 - $26,700,000). The total is made up of a demand production facility of $36,000,000, a demand administration facility of $5,000,000 and a subordinated debt facility of $7,000,000. Drawings on the demand facilities bear interest at 0.40% above the bank s prime lending rate and the subordinated debt facility bears interest at prime plus 2 basis points. Security is provided by a first charge over all of the Trust s assets. The balance is repayable on demand. While the loan is due on demand, the Trust is not subject to scheduled repayments. However, the amount available under the subordinated debt facility will decrease by $1,000,000 on October 31, 2004 and for each month until April 30, 2005, to a total credit facility balance of $41,000,000.

4.

Future income tax liability

The decrease in the future income tax liability is primarily due to larger interest payments from Enterra Energy Corp. (Enterra) to the Trust, which are deductible for Enterra (taxable to the unitholder by way of distributions) in calculating future income taxes, together with a decrease in a substantively enacted Alberta income tax rate by 1% in the first quarter and the tax impact of adopting the new accounting policies as set out in note 1.

5. Unitholders Equity

(a)

Issued Trust Units:

	Number of Units	Amount

Balance at December 31, 2003	18,955,960	$ 32,838,163
Issued for exchangeable shares	1,523,571	2,588,872
Issued in private placement, net of issue costs	2,699,400	36,838,468
Issued on acquisition of Rocky Mountain Energy Corp.	1,946,576	34,406,344
Adoption of unit-based compensation (note 1(d))	-	646,031
Balance at September 30, 2004	25,125,507	$ 107,317,878

(b) Issued Exchangeable Shares:

	Number of Units	Amount
Balance at December 31, 2003	1,995,596	$ 3,457,050
Enterra exchangeable shares exchanged for Trust Units	(1,494,437)	(2,588,872)
Issued by RMAC in acquisition of Rocky Mountain Energy Corp.	341,882	6,042,872
Balance at September 30, 2004	843,041	$ 6,911,050

The exchangeable shares are exchangeable into Trust units at an exchange ratio which is adjusted each time the Trust makes a distribution to its unitholders. The Enterra exchangeable shares exchange ratio was 1:1 on December 31, 2003 and is 1:1.07945 on September 30, 2004. The RMAC exchangeable shares exchange ratio was 1:1 on September 30, 2004.

(c)

Options:

	Number of Options	Weighted-average exercise price
Balance at December 31, 2003	-	$ -
Options granted	920,000	$14.00
Balance at September 30, 2004	920,000	$14.00

(d)

Reconciliation of earnings per unit/share calculation:

The weighted average number of units outstanding for the three and nine months ended September 30, 2004, was 23,675,830 and 22,412,317 respectively.

Three Months Ended September 30, 2003

	Net Earnings (as restated)	Weighted Average Shares Outstanding	Per Share
Basic	$ 961,591	18,821,216	$0.05
Options assumed exercised		1,973500	
Shares assumed purchased		(455,712)	
Diluted	$ 961,591	20,339,004	$0.05

Nine Months Ended September 30, 2003

	Net Earnings (as restated)	Weighted Average Shares Outstanding	Per Share
Basic	$10,184,123	18,520,774	$0.55
Options assumed exercised		1,957,566	
Shares assumed purchased		(508,616)	
Diluted	$10,184,123	19,969,724	$0.51

6. Forward contracts

On January 23, 2004, the Trust entered into physical contracts to deliver 1,000 barrels of oil per day from July 1, 2004 to December 31, 2004 at Cdn$40.50.