



ENERGY TRUST  
**Enterra**

**Q3**

2007 QUARTERLY REPORT TO  
THE UNITHOLDERS  
Nine months ended September 30, 2007

## **ENTERRA ENERGY TRUST**

### **MANAGEMENT'S DISCUSSION AND ANALYSIS**

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The following is Management's Discussion and Analysis ("MD&A") of Enterra Energy Trust ("the Trust" or "Enterra") for the nine-month period ended September 30, 2007. This MD&A should be read in conjunction with the MD&A and the consolidated financial statements, together with the accompanying notes of the Trust for the year ended December 31, 2006, as well as the unaudited interim consolidated financial statements, together with the accompanying notes of the Trust for the nine-month period ended September 30, 2007. All amounts are stated in Canadian dollars and are prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP") except where otherwise indicated. This MD&A was written as of November 13, 2007.

#### **SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS**

This MD&A includes forward-looking statements. All statements other than statements of historical facts contained in this MD&A, including statements regarding the Trust's 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 relate to the Trust, are intended to identify forward-looking statements. The Trust has based these forward-looking statements largely on the Trust's current expectations and projections about future events and financial trends that the Trust believes may affect its financial condition, results of operations, business strategy and financial needs. These forward-looking statements are subject to a number of risks, uncertainties and assumptions as described elsewhere in this MD&A.

Other sections of this MD&A may include additional factors that could adversely affect the Trust's business and financial performance. Moreover, the Trust operates in a very competitive and rapidly changing environment. New risk factors emerge from time to time and it is not possible for management to predict all risk factors, nor can the Trust assess the impact of all factors 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 statements.

The Trust undertakes no obligation, except as required by securities law, to update publicly or revise any forward-looking statements. You should not rely upon forward-looking statements as predictions of future events or performance. The Trust cannot assure you that the events and circumstances reflected in the forward-looking statements will be achieved or occur. Although the Trust believes that the expectations reflected in the forward-looking statements are reasonable, the Trust cannot guarantee future results, levels of activity, performance or achievements.

#### **SPECIAL NOTE REGARDING NON-GAAP TERMS**

This document contains the terms "funds from operations" and "netback", which are non-GAAP terms. The Trust uses these measures to help evaluate its performance. The Trust considers funds from operations a key measure for the ability of the Trust to repay debt, make distributions to unitholders and to fund future growth through capital investment. The term should not be considered as an alternative to, or more meaningful than, cash provided by operating activities as determined in accordance with Canadian GAAP as an indicator of the Trust's performance. The Trust considers netback a key measure for the ability of the Trust to analyze its operations. The term should not be considered as an alternative to, or more meaningful than, net earnings (loss) as determined in accordance with Canadian GAAP as an indicator of the Trust's performance. Funds from operations and netback, as determined by the Trust may not be comparable to that reported by other companies. The reconciliation for funds from operations to cash provided by operating activities and of netback to net earnings (loss) can be found in the non-GAAP financial measures section of this MD&A.

## **CERTAIN FINANCIAL REPORTING MEASURES**

Natural gas volumes recorded in thousand cubic feet (“mcf”) are converted to barrels of oil equivalent (“boe”) using the ratio of six (6) thousand cubic feet to one (1) barrel of oil (“bbl”). Boe’s may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead.

## **OVERVIEW AND STRATEGY**

Enterra is a Canadian oil and gas trust with trust units listed on the Toronto Stock Exchange (ENT.UN) and the New York Stock Exchange (ENT). The Trust’s head office is located in Calgary, Alberta and its United States office is located in Carney, Oklahoma.

The Trust’s portfolio of crude oil, natural gas liquids and natural gas interests is geographically diversified and is balanced between natural gas and liquids production. The Trust’s properties are located principally in Alberta, British Columbia, Saskatchewan and Oklahoma with average production for Q3 2007 of 12,798 boe/day, which was comprised of approximately 62% natural gas and 38% crude oil and natural gas liquids.

The Trust’s management discussion and analysis and its consolidated financial statements have been prepared on a going concern basis in accordance with Canadian generally accepted accounting standards. The going concern basis of presentation assumes that the Trust will continue its operations for the foreseeable future and be able to realize its assets and discharge its liabilities and commitments in the normal course of business. If the Trust is not able to refinance or repay its \$40 million second-lien facility and any potential revisions to the borrowing base on its credit facilities on November 20, 2007, then the going concern assumption would not be appropriate and adjustments to the carrying values of assets and liabilities, the reported revenue and expenses, and the balance sheet classifications used may be necessary. The Trust’s financial statements do not currently reflect any of these adjustments.

The Trust has strived to make monthly cash distributions to its unitholders of 60% to 70% of funds from operations. However, on September 17, 2007 the Trust suspended its monthly distributions in order to redirect its cash flow to the repayment of its outstanding debt. As required by the Trust’s September 28, 2007 amended credit facilities, the distributions will be suspended until at least March 31, 2008. The Trust’s distributions in Q3 2007 were approximately 55% of funds from operations. All distributions are determined by the board of directors (“Board”) of Enterra Energy Corp., as administrator of the Trust, based on the circumstances as they exist at that time and will be subject to a number of factors, many of which are beyond the Trust’s control. These factors include unforeseen events which impact the Trust’s production levels, the prices received for that production and the cost structure associated with the Trust’s operations.

## **ENTERRA’S GOAL, BUSINESS STRATEGY AND OPERATING PRINCIPLES**

Enterra’s goal has been to generate returns for its unitholders from steady and consistent increases in reserves, production and funds from operations per trust unit. To achieve that goal the Trust has adopted a three-pronged strategy as follows.

### **Organic Growth**

The Trust currently targets to invest its capital in the development of the large portfolio of lower-risk opportunities it has identified within its existing asset base. The individual nature and number of opportunities varies across the Trust’s properties, but in aggregate the Trust believes they offer a means of adding reserves and production on a basis that will be accretive to unitholders and at a pace that generally is within the Trust’s control. As a result, the Trust believes that investing in such projects is in the long-term interest of unitholders.

### **Accretive Acquisitions**

Corporate and property acquisitions are an effective means of consolidating assets, improving efficiencies in existing core areas or adding new core areas. The Trust intends to be pro-active, focused and disciplined in its approach to such acquisitions. Generally, the Trust seeks to make acquisitions that:

- are accretive to funds from operations per trust unit and accretive to at least one of reserves or production per trust unit;
- add to the Trust's portfolio of infill and step-out drilling opportunities, which the Trust believes to be lower-risk in nature;
- consolidate the Trust's position within an existing core area or create a new core area;
- leverage the Trust's existing expertise;
- have high working interests and operatorship; and
- maintain a reasonable balance among oil and natural gas production, and geographic diversification.

### **Strategic Partnerships**

The Trust actively seeks to align itself with industry partners that provide access to projects that otherwise may not be available due to the nature or degree of risk involved or due to the expertise required to properly capitalize on the opportunity. The basis of the partnerships will vary, but may involve a farmout of existing assets or a joint acquisition with a partner followed by a farmout or joint venture. The Trust's objectives in structuring these relationships include:

- providing controlled exposure to higher-risk, higher-return opportunities;
- aligning with management teams or individuals with specific experience, proven skills or a demonstrated competitive advantage;
- adding reserves and production over an extended period of time at minimal cost and risk to Enterra and, as a result, providing a source of funds for future distributions; and
- creating opportunities to purchase, at an attractive cost, assets from a partner once the risk is better defined or once the necessary expertise to exploit the opportunity has been acquired by the Trust.

In pursuing the Trust's growth strategies Enterra seeks to manage the risk to unitholders by following a number of operating principles. These principles are intended to maximize flexibility and the ability to capitalize on opportunities, while reducing the volatility and increasing the predictability of cash flow. These operating principles include:

- diversifying the source of production geographically so that Enterra is less dependent on one market for production or one area for future development;
- maintaining a reasonable balance among crude oil production, natural gas liquids production and natural gas production, so that Enterra is less vulnerable to short term price fluctuations for any single commodity;
- seeking high working interests, operatorship and ownership of associated infrastructure, so that the Trust is better able to control the pace and timing of capital expenditures;
- maintaining a multi-year inventory of lower-risk development projects so that the Trust is able to support its strategy of reinvesting in organic growth opportunities; and
- hedging up to 50% of projected gross production, up to 24 months in advance, using price collars and avoiding fixed price sales so that the Trust is less exposed to significant short-term swings in commodity prices, but has protected a base level of cash flow and preserved a degree of upside.

## **STRATEGIC ACQUISITION**

On April 30, 2007, the Trust acquired all of the issued and outstanding shares of Trigger Resources Ltd. (“Trigger Resources”) for total consideration of \$63.3 million.

Trigger Resources was a private company with operations in heavy oil and gas exploration and development in western Saskatchewan. The acquisition increased the Trust’s critical mass and footprint in the region and is expected to be accretive to production, cash flow and reserves per unit. Trigger Resources’ production at the date of acquisition was approximately 2,400 boe/day, consisting of 1,400 bbls/day of oil and 6,000 mcf/day of natural gas. Its properties largely are 100% working interest with year round access, and enjoy relatively low operating costs. The acquisition also provided the Trust with an additional 66,000 net undeveloped acres with significant drilling and development potential.

In April 2007, the Trust issued \$40 million of 8.25% convertible debentures that mature on June 30, 2012 and \$29.2 million of trust units (4,945,000 trust units). The net proceeds from the issuances were used to finance the acquisition of Trigger Resources.

## **OVERALL PERFORMANCE**

The acquisition of Trigger Resources in Q2 2007, combined with the full impact of the results of the operations from the Trust’s acquisition of assets located in Oklahoma (“Oklahoma Assets”) at the end of Q1 and early Q2 2006, positively impacted the Trust’s Q3 2007 and year to date operating and financial results. This positive impact, combined with the Trust’s lower distribution level of US\$0.06 for the months of February to September, resulted in distributions being 55% of funds from operations for Q3 2007 compared to 83% for Q3 2006 and to 68% for year to date Q3 2007 compared to 93% for the year to date 2006. On September 17, 2007 the Trust suspended its distributions for a period of at least six months in order to reduce its bank indebtedness.

Average production decreased by 2% to 12,798 boe/day in Q3 2007 from 13,070 boe/day in Q3 2006. The Trust exited the quarter with sales volumes of approximately 12,860 boe/day, 2% higher than the Q3 2006 exit rate of 12,580 boe/day.

The positive impact of the acquisitions was offset by a number of factors including natural production declines on the Trust’s properties, lower natural gas prices, higher production expenses and higher G&A expenses. Production expenses increased 24% in Q3 2007 to \$14.17/boe compared to \$11.43/boe in Q3 2006. Cash G&A expenses increased by 33% in Q3 2007 to an average of \$3.79/boe from \$2.85/boe in Q3 2006. Interest expenses declined in Q3 2007, due to the combined effect of lower average borrowings and a lower average interest rate, decreasing 21% to \$6.5 million in Q3 2007 compared to \$8.2 million in Q3 2006. As a result, funds from operations decreased by 16% to \$21.2 million in Q3 2007 from \$25.3 million in Q3 2006.

The Trust realized a net loss of \$0.78/unit compared to net earnings of \$0.07/unit in Q3 2006.

Over the course of Q3 2007, the Trust paid distributions of \$11.7 million to unitholders or US\$0.18/unit, representing decreases of 44% and 57% respectively, compared to total distributions of \$21.1 million or US\$0.42/unit in Q3 2006.

On November 20, 2007, the Trust’s \$40 million second-lien credit facility matures. Additional financing through the issuance of debt or equity or asset dispositions will be required to repay or refinance this facility. See the liquidity and capital resources section of this MD&A for further discussion on the facility. If the Trust cannot refinance or repay the non-revolving second-lien credit facility or if there are downward adjustments to the borrowing base on the revolving credit facilities that cannot be addressed through debt reduction, then the lenders can demand payment of all outstanding debt.

	Three months ended September 30,			Nine months ended September 30,		
	2007	2006	<i>Change</i>	2007	2006	<i>Change</i>
Revenues	<b>\$55,685</b>	\$73,335	(24%)	<b>\$162,566</b>	\$188,365	(14%)
Average sales (boe/day)	<b>12,798</b>	13,070	(2%)	<b>12,513</b>	12,502	-
Exit sales rate (boe/day)	<b>12,860</b>	12,580	2%	<b>12,860</b>	12,580	2%
Cash provided by operating activities	<b>\$32,112</b>	\$11,692	175%	<b>\$74,629</b>	\$38,322	95%
Funds from operations <sup>(1)</sup>	<b>\$21,195</b>	\$25,281	(16%)	<b>\$58,353</b>	\$76,559	(24%)
Net earnings (loss)	<b>\$(47,681)</b>	\$3,000	(1,689%)	<b>\$(102,553)</b>	\$4,951	(2,171%)
Net earnings (loss) per trust unit - basic	<b>\$(0.78)</b>	\$0.07	(1,214%)	<b>\$(1.73)</b>	\$0.12	(1,542%)
Weighted average number of trust units outstanding - basic	<b>61,421</b>	44,816	37%	<b>59,205</b>	42,365	40%
Average price per barrel of oil (Cdn \$)	<b>\$63.56</b>	\$66.74	(5%)	<b>\$60.58</b>	\$64.17	(6%)
Average price per mcf of natural gas (Cdn\$)	<b>\$6.74</b>	\$7.47	(10%)	<b>\$7.31</b>	\$7.40	(1%)
Production expenses per boe	<b>\$14.17</b>	\$11.43	24%	<b>\$13.84</b>	\$9.61	44%
Netback <sup>(2)</sup> per boe	<b>\$18.17</b>	\$21.90	(17%)	<b>\$17.31</b>	\$23.49	(26%)

(1) Funds from operations is a non-GAAP financial measure. See non-GAAP financial measures section of the MD&A for a reconciliation of this measure.

(2) Netback is a non-GAAP financial measure. See non-GAAP financial measures section of the MD&A for a reconciliation of this measure.

#### QUARTERLY FINANCIAL INFORMATION

	2007			2006			2005	
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Revenues	\$55,685	\$62,871	\$44,010	\$56,043	\$73,335	\$67,313	\$47,717	\$50,602
Loss before taxes and non-controlling interest	\$(41,227)	\$(8,173)	\$(72,968)	\$(101,242)	\$(6,879)	\$(10,579)	\$(3,149)	\$(28,526)
Net earnings (loss)	\$(47,681)	\$7,878	\$(62,752)	\$(69,189)	\$3,000	\$(296)	\$2,248	\$(12,937)
Net earnings (loss) per unit								
Basic and diluted	\$(0.78)	\$0.13	\$(1.12)	\$(1.40)	\$0.07	\$(0.01)	\$0.06	\$(0.37)
Distributions declared per unit (US\$)	\$0.12	\$0.18	\$0.18	\$0.36	\$0.36	\$0.54	\$0.54	\$0.52

Prior to Q4 2006, the Trust had realized steady growth in revenues for six quarters. The decreases in revenues in Q3 2007, Q1 2007 and Q4 2006 were due to a combination of lower volumes, lower realized prices and reductions in the mark to market value of the Trust's derivatives. The growth and subsequent decreases in distributions over the period reflect the changes in revenues as well as the decision by the Trust to reduce the level of its distributions in order to pursue organic growth. The significant net losses in Q3 2007, Q1 2007, Q4 2006 and Q4 2005 were due to ceiling test and goodwill impairments recorded in the periods.

## **RESULTS OF OPERATIONS**

The Trust's average production for Q3 2007 decreased by 2% to 12,798 boe/day from 13,070 boe/day in Q3 2006. The decrease reflects normal production declines in the Trust properties, countered by the acquisition of Trigger Resources and the continued development of the Oklahoma Assets. The Trust's average production during Q3 2007 consisted of 4,824 bbls/day of oil and natural gas liquids ("NGL") and 47,846 mcf/day of natural gas, resulting in a mix of 38% oil and NGL and 62% natural gas. As at September 30, 2007, the Trust had an exit production rate of approximately 12,860 boe/day.

In total in Q3 2007, the Trust participated in the drilling of 11 (3.1 net) development wells. For the nine months ended September 30, 2007, the Trust participated in the drilling of 24 (9.7 net) development wells. The drilling in Canada and Oklahoma resulted in an overall success rate of 100%.

### **Canadian Operations**

Production in Canada for Q3 2007 increased by 4% to 7,806 boe/day compared to 7,491 boe/day in Q3 2006. The increase is attributable to the acquisition of Trigger Resources on April 30, 2007, which added 1,797 boe/day to the Q3 average production, with an offset due to normal production declines for the Trust's Canadian properties. Natural gas represented approximately 46% of total production in Q3 2007 versus 39% in Q2 2006. The Q3 2007 exit rate for Canada was approximately 7,889 boe/day. Production issues at the Trust's Primate heavy oil field in Saskatchewan persisted into Q3 2007 due to difficulties experienced during the drilling of a new well in the Q2 drilling program. These difficulties caused reduced production at the offset wells in the area.

Consistent with the Trust's strategy of pursuing organic growth opportunities, the Trust continued drilling operations during the quarter. The Trust drilled 1 (1 net) development well in the Primate area in western Saskatchewan and participated in 3 (0.5 net) development wells in the Ricinus and Ferrier areas. The Trust continues to build a prospect inventory on its existing undeveloped lands in Canada.

### **U.S. Operations**

Production in the United States averaged a total of 4,993 boe/day during Q3 2007 compared to 5,579 boe/day in Q3 2006, of which 88% was natural gas. Most of the decrease in Q3 2007 was due to natural declines. However, the weather in Oklahoma was unseasonably wet with storms causing electrical outages that resulted in lost production. The Trust's Q3 2007 exit rate from its U.S. operations was approximately 4,971 boe/day.

In total, the Trust participated in the drilling of 7 (1.6 net) wells in the U.S. in Q3 2007. All of the wells were drilled in Oklahoma under an area farmout agreement. Under the agreement the Trust's partner pays 100% of the cost of drilling and completing the wells in exchange for 70% of the Trust's working interest. All of the wells drilled were successful.

**Production** *(in thousands except for volumes and percentages)*

	Three Months ended September 30,			Nine Months ended September 30,		
	2007	2006	Change	2007	2006	Change
<b>Daily Sales Volumes – Average</b>						
Oil & NGL (bbls/day)	4,824	5,221	(8%)	4,736	5,244	(10%)
Natural gas (mcf/day)	47,846	47,094	2%	46,660	43,550	7%
Total (boe/day)	12,798	13,070	(2%)	12,513	12,502	-

**Daily Sales Volumes - Exit Rate**

Oil & NGL (bbls/day)	4,694	4,714	-	4,694	4,714	-
Natural gas (mcf/day)	48,996	47,196	4%	48,996	47,196	4%
Total (boe/day)	12,860	12,580	2%	12,860	12,580	2%

**Sales Volumes mix by product**

Oil & NGL	38%	40%	38%	42%
Natural gas	62%	60%	62%	58%
	100%	100%	100%	100%

**Production by Geographic Area** *(in thousands except for volumes and percentages)*

	Three Months ended September 30, 2007		Nine Months ended September 30, 2007	
	Canada	U.S.	Canada	U.S.
<b>Daily Sales Volumes – Average</b>				
Oil & NGL (bbls/day)	4,244	580	4,059	677
Natural gas (mcf/day)	21,370	26,476	19,713	26,947
Total (boe/day)	7,806	4,993	7,345	5,168

**Daily Sales Volumes - Exit Rate**

Oil & NGL (bbls/day)	4,123	571	4,123	571
Natural gas (mcf/day)	22,595	26,401	22,595	26,401
Total (boe/day)	7,889	4,971	7,889	4,971

**Sales Volumes mix by product**

Oil & NGL	54%	12%	55%	13%
Natural gas	46%	88%	45%	87%
	100%	100%	100%	100%

**COMMODITY PRICING**

West Texas Intermediate (“WTI”) is a standard benchmark for the price of oil. WTI is expressed in US dollars per barrel (“bbl”). The Trust reports the price it receives for oil in Canadian dollars per bbl. Alberta Spot prices, represented as AECO hub pricing (“AECO”), is a standard benchmark for the price of natural gas in Western Canada. AECO prices are quoted in Canadian dollars per gigajoule (“GJ”). New York Mercantile Exchange (“Nymex”) is a standard benchmark for the price of natural gas in the United States. Nymex prices are expressed in US dollars per million British Thermal Units (“mmbtu”). To simplify comparison, both an mmbtu and a GJ are approximately equal to a mcf of gas.

Natural gas prices on the Nymex decreased US\$0.40/mmbtu or 6%, from Q3 2006, averaging US\$6.13/mmbtu in Q3 2007. In Canada, AECO pricing was down \$0.05/GJ, or 1%, from Q3 2006 levels, averaging \$6.13/GJ.

U.S. oil prices increased 7% from Q3 2006, averaging US\$75.38/bbl in Q3 2007. The effect of the increase was offset by an 8% weakening of the U.S. dollar against the Canadian dollar, with the exchange rate rising to an average of US\$0.96 per Canadian dollar in Q3 2007 from an average of US\$0.89 in Q3 2006.

The Q3 2007 average price received by the Trust for oil was down 7% to \$62.96/bbl from \$67.68/bbl in Q3 2006. The Q3 2007 average price received by the Trust for natural gas was down 16% to \$5.75/mcf from \$6.88/mcf in Q3 2006. The Trust received an additional \$0.60/bbl in Q3 2007 from its oil commodity contracts compared to a loss of \$0.94/bbl in Q3 2006. The Trust received an additional \$0.99/mcf in Q3 2007 from its natural gas commodity contracts compared to an additional \$0.59/mcf in Q3 2006.

**Pricing** (in thousands except for volumes and pricing)

	Three Months ended September 30,			Nine Months ended September 30,		
	2007	2006	Change	2007	2006	Change
<b>Pricing Benchmarks</b>						
WTI (US\$/bbl)	<b>75.38</b>	70.48	7%	<b>66.23</b>	68.22	(3%)
Average exchange rate: US\$ to Cdn\$1.00	<b>0.96</b>	0.89	8%	<b>0.91</b>	0.88	3%
WTI (Cdn\$/bbl)	<b>78.52</b>	79.19	(1%)	<b>72.78</b>	77.52	(6%)
AECO monthly index (Cdn\$/GJ)	<b>5.59</b>	5.64	(1%)	<b>6.69</b>	6.40	5%
Nymex (US\$/mmbtu)	<b>6.13</b>	6.53	(6%)	<b>6.88</b>	7.48	(8%)
<b>Average Prices Received by the Trust</b>						
Oil (Cdn\$ per bbl)	<b>62.96</b>	67.68	(7%)	<b>60.36</b>	64.71	(7%)
Natural gas (Cdn\$ per mcf)	<b>5.75</b>	6.88	(16%)	<b>6.83</b>	6.76	1%
Oil commodity contract settlements (Cdn\$ per bbl)	<b>0.60</b>	(0.94)	(164%)	<b>0.22</b>	(0.54)	(141%)
Natural gas commodity contract settlements (Cdn\$ per mcf)	<b>0.99</b>	0.59	68%	<b>0.48</b>	0.64	(25%)
Combined Oil (Cdn\$ per bbl)	<b>63.56</b>	66.74	(5%)	<b>60.58</b>	64.17	(6%)
Combined Natural gas (Cdn\$ per mcf)	<b>6.74</b>	7.47	(10%)	<b>7.31</b>	7.40	(1%)
Total <sup>(1)</sup> (Cdn\$ per boe)	<b>48.99</b>	53.26	(8%)	<b>49.99</b>	52.24	(4%)

(1) Includes NGL's

The Trust has a policy of hedging up to 50% of projected gross production up to 24 months in advance, using price collars and avoiding fixed price sales, so that the Trust is less exposed to significant short-term swings in commodity prices. Fluctuations in the estimated fair value of the risk management program resulted in a non-cash decrease in oil and natural gas revenues of \$2.0 million in Q3 2007, compared to a non-cash increase in oil and natural gas revenue of \$9.3 million in Q3 2006.

At September 30, 2007, the Trust had the following financial derivatives and fixed price contracts outstanding:

Derivative Instrument	Commodity	Price	Volume (per day)	Period
Collar	Gas	8.00 by 12.00 (Cdn\$/GJ)	10,000 GJ	November 1, 2007 – March 31, 2008
Floor	Gas	8.00 (US\$/mmbtu)	10,000 mmbtu	November 1, 2007 – March 31, 2008
Collar	Gas	7.00 by 11.00 (US\$/mmbtu)	3,000 mmbtu	November 1, 2007 – March 31, 2008
Fixed	Gas	7.95 (US\$/mmbtu)	2,000 mmbtu	April 1, 2008 – October 31, 2008
Collar	Gas	6.50 by 10.50 (US\$/mmbtu)	3,000 mmbtu	April 1, 2008 – October 31, 2008
Collar	Oil	55.00 by 80.50 (US\$/bbl)	1,000 bbl	October 1, 2007 – December 31, 2007
Collar	Oil	55.00 by 80.50 (US\$/bbl)	1,000 bbl	October 1, 2007 – December 31, 2007
Collar	Oil	55.00 by 78.60 (US\$/bbl)	500 bbl	October 1, 2007 – December 31, 2007
Collar	Oil	55.00 by 75.25 (US\$/bbl)	500 bbl	January 1, 2008 – June 30, 2008
Collar	Oil	62.00 by 78.00 (US\$/bbl)	500 bbl	January 1, 2008 – June 30, 2008
Collar	Oil	62.00 by 75.50 (US\$/bbl)	500 bbl	January 1, 2008 – March 31, 2008
Collar	Oil	62.00 by 75.60 (US\$/bbl)	500 bbl	April 1, 2008 – June 30, 2008
Collar	Oil	62.00 by 80.50 (US\$/bbl)	500 bbl	July 1, 2008 – December 31, 2008
Collar	Oil	62.00 by 80.05 (US\$/bbl)	500 bbl	July 1, 2008 – December 31, 2008
Fixed purchase	Power (Alberta)	62.90 (Cdn\$/Mwh)	72 Mwh	October 1, 2007 – December 31, 2009

As at September 30, 2007 the above commodity contracts had a net mark-to-market value of \$4.0 million.

## REVENUES

Total oil and natural gas revenues decreased by 24% in Q3 2007 from Q3 2006 largely due to lower pricing received for the oil and natural gas. The decrease in price was compounded by the decrease in the unrealized mark-to-market loss on the Trust's price risk management program. On a realized basis, revenues from oil, NGL and natural gas decreased by 10% to \$57.7 million in Q3 2007 from \$64.0 million in Q3 2006. Oil and NGL revenues decreased 12% to \$28.0 million in Q3 2007 due to lower production volumes related to natural declines and lower commodity prices received. Natural gas revenues decreased 8% in Q3 2007 to \$29.7 million due to lower commodity prices received for natural gas.

<b>Revenues (in thousands)</b>						
	<u>Three Months ended September 30,</u>			<u>Nine Months ended September 30,</u>		
	<b>2007</b>	2006	<i>Change</i>	<b>2007</b>	2006	<i>Change</i>
<b>Revenues</b>						
Oil and NGL	<b>\$28,016</b>	\$31,660	(12%)	<b>\$77,663</b>	\$90,341	(14%)
Natural gas	<b>29,661</b>	32,385	(8%)	<b>93,116</b>	87,955	6%
	<b>57,677</b>	64,045	(10%)	<b>170,779</b>	178,296	(4%)
Unrealized mark-to-market gains (loss) on oil and natural gas derivative instruments	<b>(1,992)</b>	9,290	(121%)	<b>(8,213)</b>	10,069	(182%)
Oil and natural gas revenues	<b>\$55,685</b>	\$73,335	(24%)	<b>\$162,566</b>	\$188,365	(14%)

<b>Revenues by Geographic area (in thousands)</b>				
	<u>Three Months ended September 30, 2007</u>		<u>Nine Months ended September 30, 2007</u>	
	<b>Canada</b>	<b>U.S.</b>	<b>Canada</b>	<b>U.S.</b>
<b>Revenues</b>				
Oil and NGL	<b>\$23,957</b>	<b>\$ 4,059</b>	<b>\$64,470</b>	<b>\$13,193</b>
Natural gas	<b>13,350</b>	<b>16,311</b>	<b>39,344</b>	<b>53,772</b>
	<b>37,307</b>	<b>20,370</b>	<b>103,814</b>	<b>66,965</b>
Unrealized mark-to-market gains (loss) on oil and natural gas derivative instruments	<b>(1,478)</b>	<b>(514)</b>	<b>(4,194)</b>	<b>(4,019)</b>
	<b>\$35,829</b>	<b>\$19,856</b>	<b>\$99,620</b>	<b>\$62,946</b>

## ROYALTIES

Royalties, which include Crown, freehold and overriding royalties and wellhead taxes, less Alberta Royalty Tax Credits (“ARTC”), vary depending on the jurisdiction, the volumes produced, total volumes sold and the price received by the Trust for the sales. Overall, royalties decreased in Q3 2007 compared to Q3 2006 as a result of royalty rebates realized in the U.S. division. The U.S. division applied for, and received, a royalty rebate for its horizontally drilled wells in the state of Oklahoma. The Trust realized rebates of \$2.5 million for royalties paid in 2006 and 2007. The Trust expects to receive the 6% rebate for all new horizontally drilled wells for a time period of 24 months after each well is drilled.

In late October 2007, the Alberta provincial government announced a new oil and gas royalty regime to take effect January 1, 2009. The government has only recently provided the details of the royalty regime and the Trust is still assessing the net economic impact on its future financial performance and reserve values. At a high level the new regime extracts considerable additional economic rent from high rate oil and gas wells such as at the Trust’s Clair oil field and at its Ricinus Leduc gas field. At the same time low rate wells such as those at the Trust’s east Alberta fields may see little change or a slight reduction in royalties. All royalty rates are now heavily influenced by commodity prices. Overall, the Trust produces approximately 38% of its production in Alberta.

<b>Royalties</b> (in thousands except for percentages and per boe amounts)						
	Three Months ended September 30,			Nine Months ended September 30,		
	2007	2006	Change	2007	2006	Change
Royalties	<b>\$9,421</b>	\$12,342	(24%)	<b>\$34,505</b>	\$37,092	(7%)
As a percentage of oil, NGL and natural gas revenues	<b>16%</b>	19%		<b>20%</b>	21%	
Royalties per boe	<b>\$8.00</b>	\$10.26	(22%)	<b>\$10.10</b>	\$10.87	(7%)

<b>Royalties by Geographic Area</b> (in thousands except for percentages and per boe amounts)				
	Three Months ended September 30, 2007		Nine Months ended September 30, 2007	
	Canada	U.S.	Canada	U.S.
Royalties	<b>\$7,188</b>	<b>\$2,233</b>	<b>\$20,531</b>	<b>\$13,974</b>
As a percentage of oil, NGL and natural gas revenues	<b>19%</b>	<b>11%</b>	<b>20%</b>	<b>21%</b>
Royalties per boe	<b>\$10.01</b>	<b>\$4.86</b>	<b>\$10.24</b>	<b>\$9.90</b>

## OTHER INCOME

Other revenues for Q3 2007 represents realized gains of \$0.3 million (\$3.9 million for the nine months ended September 30, 2007) and mark-to-market losses of \$0.1 million (\$2.4 million for the nine months ended September 30, 2007) on the sale of investments in securities owned by the Trust’s U.S. operations.

## PRODUCTION EXPENSES

In Q3 2007, operating costs increased 21% over Q3 2006 to \$16.7 million. On a per boe basis, operating costs in Q3 2007 increased 24% to \$14.17/boe compared to \$11.43/boe for Q3 2006.

### Canadian Assets

In Canada in Q3 2007, the average operating expense increased by 31% to \$16.64/boe versus \$12.75/boe in Q3 2006. Total operating expenses increased 36% in Q3 2007 to \$11.9 million from \$8.8 million in Q3 2006. During the quarter, the Trust experienced unexpected operating issues that contributed adversely to both production and operating expenses. In late Q2, the Trust drilled four wells in the Primate field in Saskatchewan, one of which encountered difficulties drilling and adversely affected the production of nearby, offset heavy oil producers. Subsequently, the Trust incurred additional expenses at Primate in attempt to restore this lost production. Further expenses were incurred at Sylvan Lake late in the quarter in well repairs and a plant turnaround. Also during August, a water injection pipeline failure at Clair added to production expenses.

### U.S. Assets

Unit operating expenses for the U.S. assets for Q3 2007 increased 7% to \$10.32 per boe from \$9.66 per boe, while total operating expenses fell to \$4.7 million in Q3 2007 compared to \$5.0 million in Q3 2006. In Oklahoma during Q3, unusual weather patterns including severe electrical storms and record setting rainfall plagued operations. Lightning was the cause of not only surface equipment failure including transformers and pump drive heads, but also downhole equipment failure. As is the nature of the Trust's Hunton dewatering play, well production takes time to restore to previous levels as water is pumped off and hydrocarbon flow ramps back to previous rates. As well, during Q3 2007, unexpected delays in the delivery of electricity provided by an electrical utility co-op, as well as changes to the power specifications caused delays in bring on new wells recently drilled by the Trust's strategic partner.

#### **Production Expenses** (in thousands except for percentages and per boe amounts)

	Three Months ended September 30,			Nine Months ended September 30,		
	2007	2006	Change	2007	2006	Change
Production expenses	\$16,687	\$13,745	21%	\$47,278	\$32,791	44%
Production expenses per boe	\$14.17	\$11.43	24%	\$13.84	\$9.61	44%

#### **Production Expenses by Geographic Area** (in thousands except for percentages and per boe amounts)

	Three Months ended September 30,		Nine Months ended September 30,	
	Canada	U.S.	Canada	U.S.
Production expenses	\$11,948	\$4,739	\$32,160	\$15,118
Production expenses per boe	\$16.64	\$10.32	\$16.04	\$13.84

## GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative (“G&A”) expenses increased by 10% in Q3 2007 to \$5.4 million from \$4.9 million in Q3 2006. The change largely is attributable to the increase in personnel and administrative functions required by the larger asset base of the Trust, the expansion into the U.S., and the decision to pursue organic growth opportunities. G&A per boe increased by 12% to \$4.57/boe in Q3 2007 compared to \$4.07/boe in Q3 2006. Within G&A, non-cash unit based compensation decreased to \$0.9 million in Q3 2007 from \$1.5 million in Q3 2006. This non-cash unit based compensation includes expenses for both unit option plans and the performance and restricted unit plans.

	Three Months ended			Nine Months ended		
	September 30,			September 30,		
	2007	2006	Change	2007	2006	Change
G&A expenses – cash	\$4,460	\$3,426	30%	14,491	\$10,067	44%
G&A expenses – non cash	913	1,468	(38%)	2,940	2,700	9%
Total G&A expenses	\$5,373	\$4,894	10%	\$17,431	\$12,767	37%
G&A per boe – cash	\$3.79	\$2.85	33%	\$4.24	\$2.95	44%
G&A per boe – non cash	0.78	1.22	(36%)	0.86	0.79	9%
Total G&A per boe	\$4.57	\$4.07	12%	\$5.10	\$3.74	36%

## INTEREST EXPENSE

Interest expense decreased in Q3 2007 compared to Q3 2006 due to lower total debt and a lower average cost of borrowing. The Trust’s current capital structure includes bank indebtedness and convertible debentures. During Q2 2007, the Trust issued \$40 million of 8.25% convertible debentures to partially fund the purchase price of Trigger Resources. The total of the Trust’s loans and convertible debentures at the end of Q3 2007 was \$300.3 million or 11% lower than at the end of Q3 2006 and overall bears a lower interest rate than the debt outstanding during Q3 2006.

	Three Months ended			Nine Months ended		
	September 30,			September 30,		
	2007	2006	Change	2007	2006	Change
Bank indebtedness, capital lease, and notes payable at end of period	\$188,998	\$336,595	(44%)	\$188,998	\$336,595	(44%)
Convertible debentures	111,285	-	-	111,285	-	-
Total convertible debentures, bank indebtedness, capital lease, and notes payable at end of period	\$300,283	\$336,595	(11%)	\$300,283	\$336,595	(11%)
Cash interest expense on bank indebtedness, capital lease, and notes payable	\$3,279	\$8,202	(60%)	\$9,167	\$18,159	(50%)
Non-cash interest expense on bank indebtedness, capital lease, and notes payable	324	-	-	646	-	-
Cash interest expense on convertible debentures	2,451	-	-	6,208	-	-
Non-cash interest expense on convertible debentures	398	-	-	932	-	-
Total interest expense	\$6,452	\$8,202	(21%)	\$16,953	\$18,159	(7%)
Cash interest expense per boe on bank indebtedness, capital lease, and notes payable	\$2.78	\$6.82	(59%)	\$2.68	\$5.32	(50%)
Cash interest expense per boe on convertible debentures	2.08	-	-	1.82	-	-
Total cash interest expense per boe	\$4.86	\$6.82	(29%)	\$4.50	\$5.32	(15%)

## DEPLETION, DEPRECIATION AND ACCRETION INCLUDING CEILING TEST IMPAIRMENTS (“DD&A”)

DD&A expense decreased by 14% in Q3 2007 to \$31.6 million compared to \$36.7 million in Q3 2006 due to the lower property, plant and equipment value of the Trust in relation to the reserves of the Trust. DD&A expense per boe, decreased to \$26.81/boe compared to \$30.49/boe in Q3 2006, due to the lower property, plant and equipment value after the ceiling test impairments at December 31, 2006 and the lower price paid for Trigger Resources in relation to its reserves.

At December 31, 2006, the Trust recorded a ceiling test impairment on its Canada and U.S. cost centers. At the end of Q1 2007 an additional provision of \$2.1 million was necessary due to a ceiling test write down in the Canada cost center. This charge was taken due to a reduction in the value of certain undeveloped lands and the incurrence of facility upgrade costs which did not result in additional reserve volumes.

	<b>Depletion, Depreciation and Accretion</b> <i>(in thousands except for percentages and per boe amounts)</i>					
	Three Months ended			Nine Months ended		
	September 30,		Change	September 30,		Change
2007	2006	2007		2006		
DD&A – excluding write down	<b>\$31,563</b>	\$36,667	(14%)	<b>\$91,989</b>	\$99,281	(7%)
Ceiling test provision	-	-	-	<b>2,111</b>	-	-
<b>DD&amp;A</b>	<b>\$31,563</b>	\$36,667	(14%)	<b>\$94,100</b>	\$99,281	(5%)
DD&A per boe – excluding impairment per boe	<b>\$26.81</b>	\$30.49	(12%)	<b>\$26.93</b>	\$29.09	(7%)
Ceiling test impairment per boe	-	-	-	<b>0.62</b>	-	-
<b>DD&amp;A per boe</b>	<b>\$26.81</b>	\$30.49	(12%)	<b>\$27.55</b>	\$29.09	(5%)

## GOODWILL IMPAIRMENT

During Q1 2007 and Q3 2007, the Trust recorded \$49.3 million and \$27.1 million, respectively, impairments on the carrying balance of goodwill in the Canadian reporting unit. The impairment was due to the reduced market price of the Trust in the quarter. The Trust has no more goodwill on the balance sheet.

## TAXES

In determining its taxable income, Enterra Energy Corp., a wholly owned subsidiary of the Trust (“the Corporation”) deducts interest payments made to the Trust, effectively transferring the income tax liability to unitholders thus reducing the Corporation’s taxable income to nil. Under the Corporation’s policy, at the discretion of the Board, funds can be withheld from distributions to fund future capital expenditures, repay debt or other purposes. In the event withholdings increased sufficiently, the Corporation could become subject to taxation on a portion of its income in the future. This can be mitigated through options including the issuance of additional trust units, increased tax pools from additional capital spending, modifications to the distribution policy or potential changes to the corporate structure.

On October 31, 2006 the Canadian Minister of Finance announced certain changes to the taxation of publicly traded trusts (“Bill C-52”). Bill C-52, the Budget Implementation Act 2007 received its third reading and was substantively enacted on June 12, 2007. Bill C-52 applies to a specified investment flow-through (“SIFT”) trust and will apply a tax at the trust level on distributions of certain income from such SIFT trust at a rate of tax comparable to the combined federal and provincial corporate tax rate. These distributions will be treated as dividends to the trust unitholders. The Trust constitutes a SIFT and as a result, the Trust and its unitholders will be subject to Bill C-52.

Bill C-52 commences January 1, 2007 for all SIFTs that began to be publicly traded after October 31, 2006 and commencing January 1, 2011 for all SIFTs that were publicly traded on or before October 31, 2006. It is expected that the Trust will not be subject to the taxation requirements of Bill C-52 until January 1, 2011.

Commencing January 1, 2011, the Trust will not be able to deduct certain of its distributed income. The Trust will become subject to a distribution tax of 31.5 percent on distributions of income and will not apply to returns of capital. The Trust is required to recognize, on a prospective basis, future income taxes on temporary differences in the Trust. In Q2 2007, a \$9.9 million reduction of the future income tax liability was recorded for temporary difference in the legal trust entity.

The acquisition of Trigger Resources resulted in the recognition of a future income tax liability of \$15.6 million representing the difference between the tax basis and the fair value assigned to the acquired assets.

## NON-GAAP FINANCIAL MEASURES

The Trust provides financial measures in the MD&A that do not have a standardized meaning prescribed by GAAP. These non-GAAP financial measures may not be comparable to similar measures presented by other entities.

The purpose of these financial measures, and their reconciliation to GAAP financial measures, are shown below. All of the measures have been calculated on a basis that is consistent with previous disclosures by the Trust.

### Netback per Boe

The Trust's netback per boe of production is summarized below:

<b>Netback per boe</b>	Three Months ended September 30,			Nine Months ended September 30,		
	<b>2007</b>	2006	<i>Change</i>	<b>2007</b>	2006	<i>Change</i>
Price received per boe (prior to unrealized MTM)	<b>\$48.99</b>	\$53.26	(8%)	<b>\$49.99</b>	\$52.24	(4%)
Royalties per boe	<b>8.00</b>	10.26	(22%)	<b>10.10</b>	10.87	(7%)
Operating expense per boe	<b>14.17</b>	11.43	24%	<b>13.84</b>	9.61	44%
Operating netback per boe	<b>26.82</b>	31.57	(15%)	<b>26.05</b>	31.76	(18%)
Cash G&A per boe	<b>3.79</b>	2.85	33%	<b>4.24</b>	2.95	44%
Cash interest expense per boe	<b>4.86</b>	6.82	(29%)	<b>4.50</b>	5.32	(15%)
<b>Netback per boe</b>	<b>\$18.17</b>	\$21.90	(17%)	<b>\$17.31</b>	\$23.49	(26%)

### Netback

Management uses netback to analyze operating performance. Netback, as presented, is not intended to represent an alternative to net earnings (loss) or other measures of financial performance calculated in accordance with GAAP. All references to netback throughout this MD&A are based on the reconciliation in the table below:

**Netback** (in thousands, except per boe)

	Three Months ended September 30,		Nine Months ended September 30,	
	<b>2007</b>	2006	<b>2007</b>	2006
<b>Net earnings (loss)</b>	<b>\$(47,681)</b>	\$3,000	<b>\$(102,553)</b>	\$ 4,951
Income taxes	<b>6,454</b>	(9,885)	<b>(19,814)</b>	(25,624)
Foreign exchange gain	<b>467</b>	343	<b>(340)</b>	526
Non-controlling interest	-	6	-	65
Ceiling test impairment	-	-	<b>2,111</b>	-
Depletion, depreciation and accretion	<b>31,563</b>	36,667	<b>91,989</b>	99,281
Goodwill impairment	<b>27,122</b>	-	<b>76,463</b>	-
Non-cash interest expense	<b>722</b>	-	<b>1,578</b>	-
Amortization of deferred financing fees	-	4,018	-	7,975
Financing fees	-	3	-	382
Non-cash general and administrative expense	<b>913</b>	1,468	<b>2,940</b>	2,700
Other income	<b>(173)</b>	-	<b>(1,457)</b>	-
Non-cash revenue	<b>1,992</b>	(9,290)	<b>8,213</b>	(10,069)
<b>Netback</b>	<b>\$21,379</b>	\$26,330	<b>\$59,130</b>	\$80,187
<b>Total boe</b>	<b>1,177</b>	1,202	<b>3,416</b>	3,413
<b>Netback per boe</b>	<b>\$18.17</b>	\$21.90	<b>\$17.31</b>	\$23.49

**Cash distributions as a percentage of funds from operations** *(in thousands except for percentages)*

	Three Months ended			Nine Months ended		
	September 30,			September 30,		
	2007	2006	Change	2007	2006	Change
Funds from operations	<b>\$21,195</b>	\$25,281	(16%)	<b>\$58,353</b>	\$76,559	(24%)
Cash distributions paid to unitholders	<b>11,740</b>	21,083	(44%)	<b>39,486</b>	70,913	(44%)
Capital additions paid with cash (1)	<b>6,412</b>	(1,181)	(643%)	<b>26,653</b>	17,107	56%
Funds from operations after cash distributions and capital additions	<b>\$3,043</b>	\$5,379	(43%)	<b>\$(7,786)</b>	\$(11,461)	(32%)
Cash distributions as a percentage of funds from operations	<b>55%</b>	83%		<b>68%</b>	93%	

(1) Excludes capital additions from acquisitions

Cash distributions as a percentage of funds from operations in Q3 2007 was 55%. During Q3 2007, the Trust's funds from operations exceeded its capital additions and cash distributions by \$3.0 million. This excess was used to increase the Trust's working capital.

To the extent that the Trust uses cash to reduce debt and finance capital additions, acquisitions and other significant expenditures, the cash that is available for distribution to unitholders will be reduced. On September 17, 2007, the Trust suspended its monthly distributions in order to redirect its cash flow to the repayment of its outstanding debt. In compliance with the Trust's current credit facilities as amended September 28, 2007, the distributions will be suspended for a minimum period of six months.

The Trust currently minimizes cash income taxes in corporate subsidiaries by maximizing deductions. However, in future periods, there may be cash income taxes if deductions in the corporate entities are not sufficient to eliminate taxable income. Taxability of the Trust is currently passed on to unitholders in the form of taxable distributions. The Trust anticipates that, commencing in 2011, new tax legislation that will subject the Trust to a tax in a manner similar to corporations will decrease the amount of cash available for distribution and thus reduce any potential cash distributions to unitholders.

**Funds from Operations**

Management uses funds from operations to analyze operating performance and leverage. Funds from operations, as presented, is not intended to represent cash provided by operating activities nor should it be viewed as an alternative to cash provided by operating activities or other measures of financial performance calculated in accordance with GAAP. All references to funds from operations throughout this MD&A are based on cash provided by operating activities, before changes in non-cash working capital, as reconciled in the table below:

**Funds from operations** *(in thousands)*

	Three Months ended		Nine Months ended	
	September 30,		September 30,	
	2007	2006	2007	2006
<b>Cash provided by operating activities</b>	<b>\$32,112</b>	\$11,692	<b>\$74,629</b>	\$38,322
Changes in non-cash working capital items	<b>10,917</b>	(13,589)	<b>16,276</b>	(38,237)
<b>Funds from operations</b>	<b>\$21,195</b>	\$25,281	<b>\$58,353</b>	\$76,559

In Q3 2007, funds from operations decreased by 16% over Q3 2006. The decrease mainly was due to lower realized prices, an increase in overall operating expenses for the Trust and higher G&A costs. These decreases were partially offset by lower interest expenses and the benefit of the results from Trigger Resources starting May 2007.

## CASH DISTRIBUTIONS PAID TO UNITHOLDERS

During Q3 2007 the Trust paid monthly cash distributions to its unitholders in US dollars. Cash distributions were paid on the 15<sup>th</sup> of the following month or the next business day if the 15<sup>th</sup> of the month falls on a weekend or a statutory holiday (for example, the August 2007 distribution was paid on September 17, 2007). These distributions were determined each month by the Board of Enterra Energy Corp., as administrator of the Trust, after review of a number of factors potentially impacting the Trust including its available prospects and opportunities, the outlook for commodity prices, other macro-economic factors and the Trust's financial position and commitments. On September 17, 2007 the Trust suspended its monthly distributions in order to redirect its cash flow to the repayment of its outstanding debt. As required by the September 28, 2007 amended credit facilities, the distributions will be suspended until at least March 31, 2008.

The monthly cash distributions per trust unit declared since the inception of the Trust are as follows:

US\$	2007	2006	2005	2004	2003
January	\$ 0.06	\$ 0.18	\$ 0.14	\$ 0.10	
February	\$ 0.06	\$ 0.18	\$ 0.14	\$ 0.10	
March	\$ 0.06	\$ 0.18	\$ 0.15	\$ 0.11	
April	\$ 0.06	\$ 0.18	\$ 0.15	\$ 0.11	
May	\$ 0.06	\$ 0.18	\$ 0.15	\$ 0.11	
June	\$ 0.06	\$ 0.18	\$ 0.16	\$ 0.12	
July	\$ 0.06	\$ 0.12	\$ 0.16	\$ 0.12	
August	\$ 0.06	\$ 0.12	\$ 0.16	\$ 0.12	
September	-	\$ 0.12	\$ 0.17	\$ 0.13	
October	-	\$ 0.12	\$ 0.17	\$ 0.13	
November		\$ 0.12	\$ 0.17	\$ 0.13	
December		\$ 0.12	\$ 0.18	\$ 0.14	\$ 0.10

*(in thousands)*

	Previously completed fiscal years			
	Three Months ended September 30, 2007	Nine Months ended September 30, 2007	2006	2005
Cash provided by operating activities	\$32,112	\$74,629	\$64,485	\$68,120
Net earnings (loss)	\$(47,681)	\$(102,553)	\$(64,239)	\$970
Cash distributions paid	\$11,740	\$39,486	\$90,487	\$66,195
Excess (shortfall) of cash provided by operating activities over cash distributions paid	\$20,372	\$35,143	\$(26,002)	\$1,925
Shortfall of net earnings (loss) over cash distributions paid	\$(59,421)	\$(142,039)	\$(154,726)	\$(65,225)

In July 2006, and again in January 2007 the Trust lowered the level of its distribution with the intent of investing any additional cash flow in activities that would allow it to replace produced reserves and offset natural production declines and thus sustain distributions. On September 17, 2007, the Trust suspended its distributions for a period of at least six months in order to partially repay its bank indebtedness. The Trust's credit facility was amended on September 28, 2007 whereby the Trust is not permitted to pay a distribution until March 31, 2008. After March 31, 2008 the Trust's credit facility limits the Trust's ability to pay distributions to less than 100% of cash flow on a trailing twelve month basis.

Distributions typically exceed net income as a result of non-cash expenses such as changes in the mark-to-market value of commodity contracts, depletion, depreciation, and accretion, future income tax expense, trust unit based compensation and goodwill impairment. These non-cash expenses result in a reduction to net income, with no impact to cash flow from operating activities. The Trust's goal was to pay cash distributions while enhancing the value of the trust units. Accordingly, the Trust expected that distributions would exceed net income in most periods. In 2006 distributions exceeded cash flows from operating activities due to the Trust's previous distribution policy. In 2006, the shortfall was funded by available credit facilities.

In Q3 2007 cash distributions were \$20.4 million less than the cash provided by operating activities and \$59.4 million greater than net earnings.

### CAPITAL EXPENDITURES

A component of the Trust's business strategy is to invest available funds not distributed to unitholders in lower-risk projects within core areas of its asset base. As well, the Trust continually seeks accretive acquisitions of oil and gas assets that will create new core areas with investment potential, or will consolidate an existing core area. Any such purchases are financed with a combination of cash flows from operations, issuing new trust units or incurring new debt.

The following table represents the Trust's capital expenditures that were paid for with cash. The table excludes certain capital expenditures, such as the portion of the cost of acquiring the Oklahoma Assets, which was paid for with non-cash consideration such as trust units.

<b>Capital Expenditures Paid with Cash</b> (in thousands except for percentages)						
	Three Months ended			Nine Months ended		
	September 30,			September 30,		
	2007	2006	Change	2007	2006	Change
Capital expenditures	\$6,412	\$13,073	(51%)	\$89,910	\$207,957	(57%)

The Trust accounts for its investment in its U.S. operations as a self sustaining operation, which means the capital assets associated with the U.S. operations (as well as all other balance sheet accounts for the U.S. operations) are subject to revaluation to the current exchange rate at each balance sheet date. The result of this revaluation is a change in the carrying value of the U.S. assets from period to period, which is not a result of capital additions or disposals.

On April 30, 2007, the Trust closed the acquisition of Trigger Resources. The results of operations of Trigger Resources are included in the Trust's financial statements as of April 30, 2007. Total consideration paid for Trigger Resources was \$63.3 million (including transaction costs of \$0.3 million).

Excluding the acquisition of Trigger Resources, during the nine months ended September 30, 2007 in Canada, the Trust spent \$15.3 million in capital expenditures; \$2.2 million on 3-D seismic in Northeastern British Columbia to aid in the development of the Trust's proved and probable reserves, \$6.9 million related to drilling and completions operations of which \$2.2 million was related to the four wells drilled on the Trigger Resources lands in Saskatchewan, \$0.7 million for the construction of facilities and pipelines and \$5.5 million for other plant and equipment. The Trust sold \$6.2 million of non-core assets during the nine-months ended September 30, 2007.

During the nine months ended September 30, 2007 in the U.S., approximately US\$4.1 million was spent to acquire lands for future development in Oklahoma. In addition, the Trust spent US\$3.8 million on completion and equipping of two salt water disposal wells and infrastructure additions to service the new wells being added by the Trust's strategic partner, Petroflow Energy Ltd. ("Petroflow"). All of the expenditures were in support of new wells being drilled under the area farmout. An additional expenditure of US\$3.25 million (before adjustments) was spent for the acquisition of assets from a working interest owner in certain oil and gas properties located in Wyoming.

During 2007 in the U.S., a salt water disposal well and its related infrastructure costs totaling US\$3.1 million was removed from property, plant and equipment and classified as a receivable. Under the Trust's agreement with Petroflow, the Trust will recover the costs of the infrastructure over a three year period. During Q3 2007, the Trust earned \$0.2 million of interest revenue on the receivable from Petroflow.

## **LIQUIDITY & CAPITAL RESOURCES**

On February 1, 2007, the Trust's \$180 million revolving extendible credit facility was divided into a \$140 million revolving extendible credit facility and a \$40 million non-revolving second-lien credit facility. The \$140 million revolving facility has the same terms as the \$180 million revolving facility that was outstanding at December 31, 2006.

On September 28, 2007, the credit facilities were amended whereby the Trust is not permitted to declare distributions until March 31, 2008. During the period to March 31, 2008, the Trust must, each month, reduce the \$140 million revolving facility and the \$20 million revolving operating facility by amounts equal to the greater of 65% of the Trust's monthly cash flow or \$2 million. Until the total borrowings under the \$140 million revolving facility and the \$20 million operating facility are reduced to an amount less than or equal to \$150 million, the applicable margins on the facilities are increased by 50 basis points. The \$40 million second-lien facility, which had increased to a \$55 million facility on July 17, 2007, was reduced back to a \$40 million facility as part of the September 28, 2007 amendment.

The \$40 million second-lien facility is a non-revolving credit facility that matures on November 20, 2007 and is subordinated to the \$140 million revolving facility and to the \$20 million revolving extendible operating facility. The facility bears interest at Canadian dollar Bankers' Acceptance or U.S. dollar LIBOR rates plus a margin of 4.5%, or Canadian or U.S. Prime rates plus a margin of 3.5% depending on the form of borrowing. The facility matures on November 20, 2007. As at September 30, 2007 all borrowings under the second-lien facility were denominated in Canadian dollars and interest was being accrued at a rate of 7.7% per annum.

Borrowings under the \$140 million revolving facility and the \$20 million revolving extendible operating facility bear interest at Canadian dollar Bankers' Acceptance or U.S. dollar LIBOR rates plus a margin of between 0.95% and 1.65%, or Canadian or U.S. Prime rates plus a margin of between 0% and 0.65% depending on the form of borrowing and the amount of debt outstanding relative to cash flow. As at September 30, 2007 all borrowings under the facilities were denominated in Canadian dollars and interest was being accrued at a rate of 6.5% per annum. At September 30, 2007, letters of credit totaling \$0.5 million reduced the amount that can be drawn under the revolving facility.

The credit facilities require the Trust to maintain certain financial covenants. As at September 30, 2007, the Trust was in compliance with the financial covenants.

In Q3 2007, the lenders reviewed the Trust's oil and gas reserves and borrowing base which maintained the revolving facility at \$140 million and the revolving extendible operating facility at \$20 million. The lenders will complete another review of the oil and gas reserves and borrowing base no later than November 20, 2007. Adjustments to the amount of the \$140 million revolving extendible credit facility may arise from their review. If there is a downward adjustment in the amount of the credit facility it will require refinancing or repayment.

On November 20, 2007 the non-revolving second-lien credit facility must be refinanced or repaid. In addition, any downward adjustments in the amount of the \$140 million revolving facility must be refinanced or repaid. The options available to the Trust for repaying the facilities include the sale of assets or the issuance of debt and equity. The ability of the Trust to raise equity is affected by the SIFT tax, as described more fully in note 10, which will apply to distributions if the Trust raises more than approximately \$165 million of equity during the period November 1, 2006 to December 31, 2007.

If the Trust cannot refinance or repay the non-revolving second-lien credit facility or downward adjustments, if any, in the revolving credit facility the lenders can demand payment of all outstanding debt.

On April 26, 2007, the Trust issued \$40.0 million of convertible debentures with a face value of \$1,000 per convertible debenture that mature on June 30, 2012, bear interest at 8.25% per annum paid semi-annually on June 30 and December 31 of each year with the first payment occurring on December 31, 2007 and are subordinated to the bank credit facilities. The convertible debentures are convertible at the option of the holder into trust units at any time prior to the maturity date at the conversion price of \$6.80 per trust unit.

At the option of the Trust, the repayment of the principal portion of the convertible debentures may be settled in trust units. The number of trust units issued upon redemption by the Trust will be calculated by dividing the principal by 95% of the weighted average trading price of trust units. The convertible debentures are not redeemable on or before June 30, 2010. On or after July 1, 2010 and prior to maturity, the convertible debentures may be redeemed in whole or in part from time to time at the option of the Trust on not more than 60 days and not less than 30 days notice, at a redemption price of \$1,050 per convertible debenture on or after July 1, 2010 and, on or before June 30, 2011, at a redemption price of \$1,025 per convertible debenture and on or after July 1, 2011 and prior to maturity, in each case, plus accrued and unpaid interest thereon, if any.

In addition to the convertible debentures, on April 26, 2007, the Trust issued \$29.2 million of trust units (4,945,000 trust units).

The net proceeds from the equity and convertible debenture issuances were used to finance the acquisition of Trigger Resources.

<i>Working Capital (in thousands)</i>	<b>September 30, 2007</b>	December 31, 2006
Working capital (deficiency)	<b>\$(183,267)</b>	\$(188,683)
Working capital (deficiency) excluding bank debt	<b>\$3,493</b>	\$(529)

The working capital deficiencies mainly relate to the classification of the bank indebtedness as current liabilities.

## RELATED PARTY TRANSACTIONS

During Q3 2007 and the nine months ended September 30, 2007, the Trust paid \$126,000 and \$625,000 respectively (Q3 2006 - \$120,000 and nine months ended Q3 2006 - \$415,000) to Macon Resources Ltd. ("Macon"), a company 100% owned by the Chief Executive Officer of the Trust, for management services provided by the Chief Executive Officer and a former Chief Financial Officer. The Trust provides office space, at no additional charge, for Macon and its employees. The amounts have been recorded at the amounts agreed to by the related parties. At September 30, 2007, \$44,000 (December 31, 2006 - \$nil) was payable by the Trust to Macon. In addition, during Q1 2007, the Trust granted 50,000 restricted units (valued at \$422,000 based on the unit price of trust units on the grant date) to Macon. On February 28, 2007, those restricted units vested and were converted into 50,441 trust units.

During 2006, the Trust entered into a farmout agreement with Petroflow, a public oil and gas company, to fund 100% of the drilling and completion costs of the Trust's undeveloped lands in Oklahoma. The Chief Executive Officer of the Trust owns, directly and indirectly, approximately 14% of the outstanding shares of Petroflow. As at September 30, 2007, the Trust had US\$2.4 million of trade receivables and US\$3.8 million of long term receivables from Petroflow (of which US\$1.4 million is due within one year and classified as current). The trade receivables relate to costs incurred by the Trust as a result of the operations of the properties. The long term receivables are for infrastructure costs that the Trust incurred which are to be repaid by Petroflow to the Trust over a three year period and accrue interest at 12% per annum. During Q3 2007, the Trust earned \$0.2 million of interest income on the long term receivables from Petroflow (nine months ended September 30, 2007 - \$0.3 million).

A former officer of the Trust has working interests in certain of the Oklahoma Assets. Balances will be payable or receivable from the former officer as a result of the operations of these properties. At September 30, 2007 no amounts were payable or receivable from the former officer. Subsequent to September 30, 2007 the officer is no longer an employee of the Trust.

## TRUST UNIT INFORMATION

The Trust is capitalized through a combination of trust units and exchangeable shares of certain of its subsidiaries. The Trust also has a unit option plan, restricted unit plan, performance unit plan and warrants to purchase trust units outstanding. The following table outlines outstanding equity instruments:

<b>Outstanding unit data (units / shares)</b>			
<b>As at</b>	<b>November 9, 2007</b>	<b>September 30, 2007</b>	<b>December 31, 2006</b>
Trust units	<b>61,432,737</b>	<b>61,432,106</b>	56,097,875
Exchangeable shares			
EEC exchangeable shares	-	-	16,337
RMG exchangeable shares	-	-	-
RMAC Series B exchangeable shares	-	-	66,720
Trust unit options	<b>1,384,334</b>	<b>1,384,334</b>	1,481,000
Restricted units	<b>1,161,534</b>	<b>420,484</b>	423,855
Performance units	<b>469,740</b>	<b>262,841</b>	212,948
Warrants	<b>301,000</b>	<b>301,000</b>	301,000
8.0% Convertible debentures (\$1,000 per debenture)	<b>80,331</b>	<b>80,331</b>	80,331
8.25% Convertible debentures (\$1,000 per debenture)	<b>40,000</b>	<b>40,000</b>	-

## CHANGES IN ACCOUNTING POLICIES

- (a) Effective January 1, 2007, the Trust adopted revised Canadian accounting standards with respect to accounting changes, which requires that (a) a voluntary change in accounting principles can be made if, and only if, the change results in more reliable and relevant information, (b) changes in accounting policies are accompanied with disclosures of prior period amounts and justification for the change, and (c) for changes in estimates, the nature and amount of the change should be disclosed. The Trust has not made any voluntary changes in accounting principles since the adoption of the revised standard.

The standard also requires that when the Trust has not adopted a new accounting standard that has been issued but not yet effective, the entity shall disclose (a) this fact; and (b) known or reasonably estimable information relevant to assessing the possible impact that application of the new standard will have on the Trust's financial statements in the period of initial application. There are currently two new Canadian accounting standards that have been issued which will require additional disclosure in the Trust's financial statements commencing January 1, 2008 about the Trust's financial instruments as well as its capital and how it is managed.

- (b) Effective January 1, 2007, the Trust adopted new Canadian accounting standards and related amendments to other standards on financial instruments. Prior periods have not been restated, except as discussed in item iii.

### i. Financial Instruments – Recognition and Measurement

This standard prescribes when a financial asset, financial liability, or non-financial derivative is to be recognized on the balance sheet and whether fair value or cost-based methods are used to measure the recorded amounts. It also specifies how financial instrument gains and losses are to be presented.

Effective January 1, 2007, the Trust's cash and cash equivalents and investments in marketable securities have been classified as held for trading and are recorded at fair value on the balance sheet. Fair values are determined directly by reference to published price quotations in an active market. Changes in the fair value of these instruments are recorded in net earnings.

All derivatives are recorded on the balance sheet at fair value. Mark-to-market adjustments on these instruments are included in net earnings, unless the instruments are designated as part of a hedge relationship. The Trust's physical purchase and sale contracts have been designated as derivatives and are recorded at estimated fair value with changes in estimated fair value each period charged to earnings.

All other financial instruments will be recorded at cost or amortized cost, subject to impairment reviews. The criteria for assessing other than temporary impairment remain unchanged. Transaction costs incurred to acquire financial instruments are included in the underlying balance.

### ii. Hedges

This standard is applicable when an entity chooses to designate a hedging relationship for accounting purposes. The new standards specify how hedge accounting is applied and what disclosures are necessary when it is applied. The Trust does not currently apply hedge accounting to any of its contracts.

iii. Comprehensive Income

This standard requires the presentation of a statement of comprehensive income and its components. Comprehensive income includes both net earnings and other comprehensive income. Other comprehensive income includes holding gains and losses on available for sale investments, gains and losses on certain derivative instruments and foreign currency gains and losses relating to self-sustaining foreign operations, all of which are not included in the calculation of net earnings until realized. The amounts previously presented as cumulative translation on the consolidated balance sheet have been included in accumulated other comprehensive income. This change, as required by the standard, was made retroactively with restatement of prior periods.

**CHANGES TO INTERNAL CONTROLS AND PROCEDURES FOR FINANCIAL REPORTING**

During the three months ended September 30, 2007 and subsequent thereto, the Trust had turnover in some of its key positions, notably the Chief Financial Officer. As a result of this turnover, the potential for control weaknesses is heightened. No other material changes were identified in the Trust's internal control of financial reporting during the three months ended September 30, 2007, that had materially affected, or are reasonably likely to materially affect, the Trust's internal control over financial reporting.

## CRITICAL ACCOUNTING ESTIMATES

The Trust continues to evolve and document its management and internal reporting systems to provide assurance that accurate, timely internal and external information is gathered and disseminated. The Trust's financial and operating results incorporate certain estimates including:

- a) estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;
- b) estimated capital expenditures on projects that are in progress;
- c) estimated depletion, depreciation and accretion that are based on estimates of oil and gas reserves, which the Trust expects to recover in the future;
- d) estimated value of asset retirement obligations that are dependent upon estimates of future costs and timing of expenditures;
- e) estimated future recoverable value of property, plant and equipment and goodwill; and
- f) estimated fair value of derivatives and investments

## ADDITIONAL INFORMATION

Additional information relating to Enterra Energy Trust, including our Annual Information Forms and Annual Reports, can be found on SEDAR at [www.sedar.com](http://www.sedar.com), on EDGAR at [www.sec.gov/edgar.shtml](http://www.sec.gov/edgar.shtml), as well as on the Trust's website at [www.enterraenergy.com](http://www.enterraenergy.com).

## ABBREVIATIONS

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bbl	barrel of oil
bbls/day	barrels of oil per day
mcf	thousand cubic feet of natural gas
mcf/day	thousands of cubic feet of natural gas per day
NGL	natural gas liquids
boe	barrels of oil equivalent (6 mcf equivalent to 1 bbl)
boe/day	barrels of oil equivalent per day
GJ	Gigajoule
mmbtu	millions of British Thermal Units
GAAP	Canadian Generally Accepted Accounting Principles
Cdn\$	Canadian dollars
US\$	United States dollars
Q1	first quarter of the year - January 1 to March 31
Q2	second quarter of the year - April 1 to June 30
Q3	third quarter of the year - July 1 to September 30
Q4	fourth quarter of the year - October 1 to December 31
Mwh	megawatt-hour

# ENTERRA ENERGY TRUST

## CONSOLIDATED BALANCE SHEETS

(Thousands of Canadian dollars)

(unaudited)

September 30, 2007

December 31, 2006

### Assets

#### Current assets

Cash	\$ 9,471	\$ 2,162
Accounts receivable	29,954	38,980
Derivatives (note 14)	4,877	10,775
Prepaid expenses, deposits and other	1,826	3,249
	<b>46,128</b>	<b>55,166</b>

Long term receivable (note 16)	2,430	-
Deferred financing charges	-	4,676
Property, plant and equipment (note 5)	617,338	659,268
Goodwill (note 6)	-	76,256
	<b>\$ 665,896</b>	<b>\$ 795,366</b>

### Liabilities

#### Current liabilities

Bank indebtedness (note 2)	\$ 186,760	\$ 188,154
Accounts payable and accrued liabilities	38,304	46,083
Distribution payable to unitholders	-	7,910
Capital lease obligations	-	1,702
Note payable (note 7)	2,238	-
Derivatives (note 14)	900	-
Future income tax liability (note 10)	1,193	-
	<b>229,395</b>	<b>243,849</b>

Convertible debentures (note 9)	111,285	78,974
Asset retirement obligations (note 8)	30,062	28,447
Future income tax liability (note 10)	37,515	40,340
	<b>408,257</b>	<b>391,610</b>

Non-controlling interest (note 11)	-	1,732
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#### Unitholders' Equity (note 12)

Unitholders' capital	667,684	635,134
Equity component of convertible debentures (note 9)	3,977	1,327
Warrants	1,215	1,215
Contributed surplus	3,478	3,195
Deficit	(373,897)	(240,777)
Accumulated other comprehensive (loss) income (note 13)	(44,818)	1,930
	<b>257,639</b>	<b>402,024</b>

Going concern and the need to refinance (note 2)	\$ 665,896	\$ 795,366
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See accompanying notes to consolidated financial statements

# ENTERRA ENERGY TRUST

## CONSOLIDATED STATEMENTS OF EARNINGS (LOSS) AND COMPREHENSIVE INCOME (LOSS)

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

(unaudited)

	Three months ended September 30, 2007	Three months ended September 30, 2006	Nine months ended September 30, 2007	Nine months ended September 30, 2006
<b>Revenues</b>				
Oil and natural gas	\$ 55,685	\$ 73,335	162,566	\$ 188,365
Royalties	(9,421)	(12,342)	(34,505)	(37,092)
	<b>46,264</b>	60,993	<b>128,061</b>	151,273
<b>Other income</b>	<b>173</b>	-	<b>1,457</b>	-
	<b>46,437</b>	60,993	<b>129,518</b>	151,273
<b>Expenses</b>				
Operating	16,687	13,745	47,278	32,791
General and administrative	5,373	4,894	17,431	12,767
Interest on bank indebtedness	3,603	8,202	9,813	18,159
Interest on convertible debentures	2,849	-	7,140	-
Financing fees	-	3	-	382
Amortization of deferred financing charges	-	4,018	-	7,975
Depletion, depreciation and accretion	31,563	36,667	91,989	99,281
Ceiling test impairment (note 5)	-	-	2,111	-
Goodwill impairment (note 6)	27,122	-	76,463	-
Foreign exchange (gain) loss	467	343	(340)	526
	<b>87,664</b>	67,872	<b>251,885</b>	171,881
Loss before taxes and non-controlling interest	(41,227)	(6,879)	(122,367)	(20,608)
Income taxes (note 10)				
Current	(47)	681	161	681
Future (reduction)	6,501	(10,566)	(19,975)	(26,305)
Earnings (loss) before non-controlling interest	(47,681)	3,006	(102,553)	5,016
Non-controlling interest (note 11)	-	6	-	65
<b>Net earnings (loss)</b>	<b>(47,681)</b>	3,000	<b>(102,553)</b>	4,951
<b>Other comprehensive income (loss)</b>				
Foreign currency translation adjustment	19,483	-	47,869	-
<b>Comprehensive income (loss)</b>	<b>\$ (67,164)</b>	\$ 3,000	<b>\$ (150,422)</b>	\$ 4,951
<b>Net earnings (loss) per trust unit (note 12)</b>				
Basic	\$ (0.78)	\$ 0.07	\$ (1.73)	\$ 0.12
Diluted	\$ (0.78)	\$ 0.07	\$ (1.73)	\$ 0.11

## CONSOLIDATED STATEMENTS OF DEFICIT

Deficit, beginning of period	\$ (318,394)	\$ (134,951)	\$ (240,777)	\$ (85,840)
Change in accounting policy (note 3)	-	-	1,009	-
Net earnings (loss)	(47,681)	3,000	(102,553)	4,951
Distributions declared	(7,822)	(18,138)	(31,576)	(69,200)
<b>Deficit, end of period</b>	<b>\$ (373,897)</b>	<b>\$ (150,089)</b>	<b>\$ (373,897)</b>	<b>\$ (150,089)</b>

See accompanying notes to consolidated financial statements

# ENTERRA ENERGY TRUST

## CONSOLIDATED STATEMENTS OF CASH FLOW

(Expressed in thousand Canadian dollars)

(unaudited)

	Three months ended September 30, 2007	Three months ended September 30, 2006	Nine months ended September 30, 2007	Nine months ended September 30, 2006
<b>Cash provided by (used in):</b>				
<b>Operating</b>				
Net earnings (loss)	\$ (47,681)	\$ 3,000	\$ (102,553)	\$ 4,951
Depletion, depreciation, accretion and ceiling test impairment	31,563	36,667	94,100	99,281
Goodwill impairment	27,122	-	76,463	-
Future income tax reduction	6,501	(10,566)	(19,975)	(26,305)
Amortization of deferred financing charges	-	4,018	-	7,975
Financial derivatives	2,264	(9,290)	7,941	(10,069)
Amortization of marketing contracts	-	-	-	(1,447)
Non-controlling interest	-	6	-	65
Foreign exchange	623	(22)	(5)	(592)
Unit-based compensation	913	1,468	2,940	2,700
Cash paid on settlement of asset retirement obligations	(507)	-	(1,811)	-
Accretion on convertible debentures and amortization of bank fees	397	-	1,253	-
Changes in non-cash working capital items	10,917	(13,589)	16,276	(38,237)
	<b>32,112</b>	<b>11,692</b>	<b>74,629</b>	<b>38,322</b>
<b>Financing</b>				
Distributions paid	(11,740)	(21,083)	(39,486)	(70,913)
Bank indebtedness	(3,016)	-	(268)	(99,739)
Bridge credit facilities	-	-	-	401,242
Bridge credit facility repayment	-	-	-	(60,630)
Issuance of convertible debentures (net of \$2,489 issue costs) (note 9)	-	-	37,511	-
Issue of trust units, net of issue costs (note 12)	-	(12)	27,438	12,247
Exercise of trust unit options	-	-	-	1,399
Proceeds from (repayment of) notes	-	-	2,397	(3,990)
Capital lease	(1,234)	(222)	(1,702)	(651)
Repayment of debt assumed on Oklahoma Asset acquisition	-	(8)	-	(14,164)
Due to JED Oil Inc., net	-	4,846	-	(2,052)
Deferred financing charges	-	(887)	-	(10,297)
	<b>(15,990)</b>	<b>(17,366)</b>	<b>25,890</b>	<b>152,452</b>
<b>Investing</b>				
Property, plant and equipment additions	(6,412)	1,181	(26,653)	(17,107)
Proceeds on dispositions	4,924	238	6,176	6,789
Acquisition of Trigger Resources (note 4)	-	-	(63,257)	-
Acquisition of Oklahoma Assets	-	(14,254)	-	(190,850)
Long term receivable	369	-	609	-
Changes in capital accounts payable	(8,587)	13,283	(9,858)	12,108
	<b>(9,706)</b>	<b>448</b>	<b>(92,983)</b>	<b>(189,060)</b>
Impact of foreign exchange on foreign cash	(90)	-	(227)	-
Change in cash	6,326	(5,226)	7,309	1,714
Cash, beginning of period	3,145	18,883	2,162	11,943
<b>Cash, end of period</b>	<b>\$ 9,471</b>	<b>\$ 13,657</b>	<b>9,471</b>	<b>\$ 13,657</b>

During the nine month period ended September 30, 2007 the Trust paid interest of \$13,508 (nine months ended September 30, 2006 - \$16,789) and taxes of \$393 (nine months ended September 30, 2006 - \$nil).

See accompanying notes to consolidated financial statements

## Enterra Energy Trust

### Notes to Consolidated Financial Statements

As at September 30, 2007 and for the three and nine months ended September 30, 2007 and 2006

(Tabular amounts are thousands of Canadian dollars, except trust unit and per trust unit amounts)  
(unaudited)

#### 1. Structure of the Trust and Basis of Presentation

The interim consolidated financial statements of Enterra Energy Trust (the “Trust”) have been prepared by management in accordance with Canadian generally accepted accounting principles. These 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, 2006, except as noted below. These financial statements should be read in conjunction with the 2006 annual consolidated financial statements. The interim consolidated financial statements contain disclosures which are supplemental to the Trust’s annual consolidated financial statements.

#### Comparative Figures

Certain comparative figures have been reclassified to conform to the presentation adopted in the current quarter.

#### 2. Going concern and the need to refinance

These consolidated financial statements have been prepared on a going concern basis in accordance with Canadian generally accepted accounting standards. The going concern basis of presentation assumes that the Trust will continue its operations for the foreseeable future and be able to realize its assets and discharge its liabilities and commitments in the normal course of business. If the Trust is not able to refinance or repay its \$40 million second lien facility and any potential revisions to the borrowing base on its credit facilities on November 20, 2007, then the going concern assumption would not be appropriate and adjustments to the carrying values of assets and liabilities, the reported revenue and expenses, and the balance sheet classifications used may be necessary. The Trust’s financial statements do not currently reflect any of these adjustments.

#### Bank indebtedness is composed of the following:

	September 30, 2007	December 31, 2006
\$140 million revolving extendible facility (\$180 million at December 31, 2006)	\$ 140,000	\$ 180,000
\$40 million non-revolving second-lien facility	40,000	-
\$20 million revolving extendible operating facility	6,411	7,695
Other credit facilities	349	459
Bank indebtedness	\$ 186,760	\$ 188,154

On February 1, 2007, the Trust’s \$180 million revolving extendible credit facility was divided into a \$140 million revolving extendible credit facility and a \$40 million non-revolving second-lien credit facility. The \$140 million revolving facility has the same terms as the \$180 million revolving facility that was outstanding at December 31, 2006.

On September 28, 2007, the credit facilities were amended whereby the Trust is not permitted to declare distributions until March 31, 2008. During the period to March 31, 2008, the Trust must, each month, reduce the \$140 million revolving facility and the \$20 million revolving extendible operating facility by amounts equal to the greater of 65% of the Trust’s monthly available cash flow or \$2 million. Until the total borrowings under the \$140 million revolving facility and the \$20 million operating facility are reduced to an amount less than or equal to \$150 million, the applicable margins on the facilities are increased by 0.5%. The \$40 million second-lien facility, which had increased to a \$55 million facility on July 17, 2007, was reduced back to a \$40 million facility as part of the September 28, 2007 amendment.

## **Enterra Energy Trust**

### **Notes to Consolidated Financial Statements**

As at September 30, 2007 and for the three and nine months ended September 30, 2007 and 2006

*(Tabular amounts are thousands of Canadian dollars, except trust unit and per trust unit amounts)  
(unaudited)*

The \$40 million second-lien facility is a non-revolving credit facility that matures on November 20, 2007 and is subordinated to the \$140 million revolving facility and to the \$20 million revolving extendible operating facility. The facility bears interest at Canadian dollar Bankers' Acceptance or U.S. dollar LIBOR rates plus a margin of 4.5%, or Canadian or U.S. Prime rates plus a margin of 3.5% depending on the form of borrowing. As at September 30, 2007 all borrowings under the second-lien facility were denominated in Canadian dollars and interest was being accrued at a rate of 7.7% per annum.

Borrowings under the \$140 million revolving facility and the \$20 million revolving extendible operating facility bear interest at Canadian dollar Bankers' Acceptance or U.S. dollar LIBOR rates plus a margin of between 0.95% and 1.65%, or Canadian or U.S. Prime rates plus a margin of between 0% and 0.65% depending on the form of borrowing and the amount of debt outstanding relative to cash flow. As at September 30, 2007 all borrowings under the facilities were denominated in Canadian dollars and interest was being accrued at a rate of 6.5% per annum. At September 30, 2007, letters of credit totaling \$0.5 million reduced the amount that can be drawn under the revolving facility.

The credit facilities require the Trust to maintain certain financial covenants. As at September 30, 2007, the Trust was in compliance with the financial covenants.

In Q3 2007, the lenders reviewed the Trust's borrowing base which maintained the revolving facility at \$140 million and the revolving extendible operating facility at \$20 million. The lenders will complete another review of the borrowing base no later than November 20, 2007. Adjustments to the amount of the \$140 million revolving extendible credit facility and the \$20 million operating facility may arise from their review. If there is a downward adjustment in the amount of the credit facility it will require refinancing or repayment.

On November 20, 2007 the non-revolving second-lien credit facility must be refinanced or repaid. In addition, any downward adjustments in the amount of the \$140 million revolving facility must be refinanced or repaid. The options available to the Trust for repaying the facilities include the sale of assets or the issuance of debt and equity. The ability of the Trust to raise equity is affected by the specified investment flow-through tax ("SIFT"), as described more fully in note 10, which will apply to distributions if the Trust raises more than approximately \$165 million of equity during the period November 1, 2006 to December 31, 2007.

If the Trust cannot refinance or repay the non-revolving second-lien credit facility or downward adjustments, if any, in the revolving credit facility the lenders can demand payment of all outstanding debt.

### **3. Adoption of New Accounting Standards**

- (a) Effective January 1, 2007, the Trust adopted revised Canadian accounting standards with respect to accounting changes, which requires that (a) a voluntary change in accounting principles can be made if, and only if, the change results in more reliable and relevant information, (b) changes in accounting policies are accompanied with disclosures of prior period amounts and justification for the change, and (c) for changes in estimates, the nature and amount of the change should be disclosed. The Trust has not made any voluntary changes in accounting principles since the adoption of the revised standard.

The standard also requires that when the Trust has not adopted a new accounting standard that has been issued but not yet effective, the entity shall disclose (a) this fact; and (b) known or reasonably estimable information relevant to assessing the possible impact that application of the new standard

## **Enterra Energy Trust**

### **Notes to Consolidated Financial Statements**

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will have on the Trust's financial statements in the period of initial application. There are currently two new Canadian accounting standards that have been issued which will require additional disclosure in the Trust's financial statements commencing January 1, 2008 about the Trust's financial instruments as well as its capital and how it is managed.

- (b) Effective January 1, 2007, the Trust adopted new Canadian accounting standards and related amendments to other standards on financial instruments. Prior periods have not been restated, except as discussed in item iii.

#### i. Financial Instruments – Recognition and Measurement

This standard prescribes when a financial asset, financial liability, or non-financial derivative is to be recognized on the balance sheet and whether fair value or cost-based methods are used to measure the recorded amounts. It also specifies how financial instrument gains and losses are to be presented.

Effective January 1, 2007, the Trust's cash and cash equivalents and investments in marketable securities have been classified as held for trading and are recorded at fair value on the balance sheet. Fair values are determined directly by reference to published price quotations in an active market. Changes in the fair value of these instruments are recorded in net earnings.

All derivatives are recorded on the balance sheet at fair value. Mark-to-market adjustments on these instruments are included in net earnings, unless the instruments are designated as part of a hedge relationship. The Trust's physical purchase and sale contracts have been designated as derivatives and are recorded at estimated fair value with changes in estimated fair value each period charged to earnings.

All other financial instruments are recorded at cost or amortized cost, subject to impairment reviews. The criteria for assessing an other than temporary impairment remain unchanged. Transaction costs incurred to acquire financial instruments are included in the balance.

Embedded derivatives that do not meet certain exemptions are also required to be separately accounted for at fair value with changes in fair value included in earnings. The Trust did not identify any significant embedded derivatives that required separate accounting as at January 1, 2007.

#### ii. Hedges

This standard is applicable when an entity chooses to designate a hedging relationship for accounting purposes. The new standard specifies how hedge accounting is applied and what disclosures are necessary when it is applied. The Trust does not currently apply hedge accounting.

#### iii. Comprehensive Income

This standard requires the presentation of a statement of comprehensive income and its components. Comprehensive income includes net earnings (loss), holding gains and losses on available for sale investments, gains and losses on certain derivative instruments and foreign currency gains and losses relating to self-sustaining foreign operations, all of which are not included in the calculation of net earnings until realized. The amounts previously presented as cumulative translation adjustment on the consolidated balance sheet have been included in accumulated other comprehensive income. This change, as required by the standard, was made retroactively with restatement of prior periods.

**Enterra Energy Trust**  
**Notes to Consolidated Financial Statements**

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As at January 1, 2007 the effect on the Trust's balance sheet of adopting these standards is summarized below.

	January 1, 2007		
	As reported	Adjusted on adoption of financial instruments standards	Restated
<b>Assets:</b>			
Current assets	\$ 55,166	\$ 2,637 (a)(b)	\$ 57,803
Property, plant and equipment	659,268	-	659,268
Deferred finance charges	4,676	(4,676) (b)	-
Goodwill	76,256	-	76,256
	<u>\$ 795,366</u>	<u>\$ (2,039)</u>	<u>\$ 793,327</u>
<b>Liabilities:</b>			
Current liabilities	\$ 243,849	\$ -	\$ 243,849
Convertible debentures	78,974	(3,481) (b)	75,493
Asset retirement obligations	28,447	-	28,447
Future income tax	40,340	432 (a)	40,772
	<u>391,610</u>	<u>(3,049)</u>	<u>388,561</u>
Non-controlling interest	1,732	-	1,732
<b>Unitholder's Equity</b>			
Unitholders' capital	635,134	-	635,134
Equity component of convertible debentures	1,327	-	1,327
Warrants	1,215	-	1,215
Contributed surplus	3,195	-	3,195
Cumulative translation adjustment	1,930	(1,930) (c)	-
Deficit	(240,777)	1,010 (a)	(239,767)
Accumulated other comprehensive income	-	1,930 (c)	1,930
	<u>402,024</u>	<u>1,010</u>	<u>403,034</u>
	<u>\$ 795,366</u>	<u>\$ (2,039)</u>	<u>\$ 793,327</u>

**Notes:**

(a) Physical purchase and sale contracts have been designated as derivatives and are measured at their estimated fair value of \$1.4 million with the offset, as required on adoption of the new standards, included in retained earnings (\$1.0 million net of income taxes).

(b) Convertible debenture financing costs of \$3.5 million, previously classified as deferred financing charges, are reclassified to convertible debentures. Financing fees of \$1.2 million have been reclassified to prepaid expenses, deposits and other and are amortized over the term of the related credit facilities.

(c) The cumulative translation adjustment is reclassified to accumulated other comprehensive income.

## Enterra Energy Trust

### Notes to Consolidated Financial Statements

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#### 4. Acquisition

On April 30, 2007, the Trust acquired all of the issued and outstanding shares of Trigger Resources Ltd. ("Trigger Resources"). The results of the operations of Trigger Resources are included in the Trust's consolidated financial statements as of April 30, 2007.

Trigger Resources was a private company with operations in heavy oil and gas exploration and development in western Saskatchewan. The acquisition increased the Trust's operations in the region and provides additional reserves, production and cash flow. The acquisition also provides the Trust with additional net undeveloped acres with drilling and development potential.

The acquisition was accounted for using the purchase method of accounting with the allocation of the purchase price and consideration paid as follows:

<b>Allocation of purchase price:</b>	
Current assets	\$ 2,806
Property, plant and equipment	81,382
Current liabilities	(2,781)
Future income tax liability	(15,576)
Asset retirement obligations	(2,574)
	<hr/>
	\$ 63,257

  

<b>Consideration:</b>	
Cash	\$ 62,965
Transaction costs	292
	<hr/>
	\$ 63,257

The purchase price allocation is preliminary and subject to change.

**Enterra Energy Trust****Notes to Consolidated Financial Statements**

As at September 30, 2007 and for the three and nine months ended September 30, 2007 and 2006

*(Tabular amounts are thousands of Canadian dollars, except trust unit and per trust unit amounts)  
(unaudited)***5. Property, Plant and Equipment**

September 30, 2007			
	Cost	Accumulated depletion and depreciation	Net
Petroleum and natural gas properties	\$ 1,061,794	\$ 447,332	\$ 614,462
Office furniture and equipment	5,185	2,309	2,876
	<b>\$ 1,066,979</b>	<b>\$ 449,641</b>	<b>\$ 617,338</b>

  

December 31, 2006			
	Cost	Accumulated depletion and depreciation	Net
Petroleum and natural gas properties	\$1,011,399	\$355,304	\$656,095
Office furniture and equipment	5,118	1,945	3,173
	<b>\$1,016,517</b>	<b>\$357,249</b>	<b>\$659,268</b>

During Q3 2007 \$0.3 million of general and administrative expenses were capitalized and included in the cost of the petroleum and natural gas properties (Q3 2006 – \$nil).

At September 30, 2007 costs of undeveloped land of \$36,454,000 (December 31, 2006 - \$25,876,000) were excluded from and \$13,697,000 (December 31, 2006 - \$8,018,000) of future development costs were added to the calculation of depletion expense for the Canadian cost centre. At September 30, 2007 costs of undeveloped land of \$8,819,000 (December 31, 2006 - \$16,848,000) were excluded from and \$2,984,000 (December 31, 2006 - \$3,480,000) of future development costs were added to the calculation of depletion expense for the United States cost centre.

Depletion and depreciation expense related to the Canadian and the US cost centers for the three months ended September 30, 2007 were \$20,055,000 and \$10,961,000 respectively (three months ended September 30, 2006 - \$23,906,000 and \$12,246,000) and for the nine months ended September 30, 2007 were \$57,455,000 and \$32,826,000 respectively (nine months ended September 30, 2006 - \$68,649,000 and \$26,124,000).

The Trust completed ceiling test calculations for the Canadian and U.S. cost centers at September 30, 2007 to assess the recoverability of costs recorded in respect of the petroleum and natural gas properties. The ceiling tests did not result in a write down for either cost center (March 31, 2007 - \$2,111,000 write down of property, plant and equipment in the Canadian cost center).

**6. Goodwill Impairment**

During Q1 2007 and Q3 2007, the Trust recorded impairments of \$49.3 million and \$27.1 million, respectively, on the carrying balance of goodwill in the Canadian reporting unit.

## Enterra Energy Trust

### Notes to Consolidated Financial Statements

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#### 7. Note Payable

The Trust has a \$2,238,000 (US\$2,250,000) note payable for the purchase of certain natural gas interests in the U.S. The note is secured by certain specified assets, bears interest at 10% and was due on October 31, 2007.

On October 31, 2007, the Trust paid US\$850,000 of the note payable and revised the remaining balance whereby US\$400,000 is due on November 30, 2007, US\$400,000 is due on December 31, 2007, US\$400,000 is due on January 31, 2008 and US\$200,000 is due on February 29, 2008. All other terms of the note remain unchanged.

#### 8. Asset Retirement Obligations

The asset retirement obligations were estimated by management based on the Trust's working interest in its wells and facilities, estimated costs to remediate, reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred. At September 30, 2007, the Trust estimated the asset retirement obligation to be \$30,062,000 (December 31, 2006 - \$28,447,000), based on a total future liability of \$49,965,000 (December 31, 2006 - \$49,442,000). These obligations will be settled at the end of the useful lives of the underlying assets, which currently averages 6 years, but extends up to 21 years into the future. This amount has been calculated using an inflation rate of 2% and discounted using a credit-adjusted risk-free interest rate of 8%.

The following table reconciles the asset retirement obligations:

Asset retirement obligation, December 31, 2006	\$	28,447
Increases in liabilities during the year related to:		
Acquisition of Trigger Resources		2,574
Additions		475
Disposals		(337)
Accretion expense		1,708
Costs incurred		(1,811)
Foreign exchange		(994)
<b>Asset retirement obligation, September 30, 2007</b>	<b>\$</b>	<b>30,062</b>

## Enterra Energy Trust

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#### 9. Convertible Debentures

On April 26, 2007, the Trust issued \$40,000,000 of convertible debentures with a face value of \$1,000 per convertible debenture that mature on June 30, 2012, bear interest at 8.25% per annum paid semi-annually on June 30 and December 31 of each year with the first payment occurring on December 31, 2007 and are subordinated to the bank credit facilities. The convertible debentures are convertible at the option of the holder into trust units at any time prior to the maturity date at the conversion price of \$6.80 per trust unit.

At the option of the Trust, the repayment of the principal portion of the convertible debentures may be settled in trust units. The number of trust units issued upon redemption by the Trust will be calculated by dividing the principal by 95% of the weighted average trading price of trust units. The convertible debentures are not redeemable on or before June 30, 2010. On or after July 1, 2010 and prior to maturity, the convertible debentures may be redeemed in whole or in part from time to time at the option of the Trust on not more than 60 days and not less than 30 days notice, at a redemption price of \$1,050 per convertible debenture on or after July 1, 2010 and, on or before June 30, 2011, at a redemption price of \$1,025 per convertible debenture and on or after July 1, 2011 and prior to maturity, in each case, plus accrued and unpaid interest thereon, if any.

At September 30, 2007, the Trust had \$80.3 million in 8% convertible debentures outstanding with an estimated fair value of \$73.9 million and \$40.0 million in 8.25% convertible debentures outstanding with an estimated fair value of \$36.0 million.

	8% Series	8.25% Series	Total
Balance, December 31, 2006	\$ 78,974	\$ -	\$ 78,974
April 28, 2007 issuance	-	40,000	40,000
Portion allocated to equity	-	(2,765)	(2,765)
Issue costs reclassified against carrying value (note 3)	(3,481)	-	(3,481)
Issue costs	(305)	(2,069)	(2,374)
Accretion of discount	625	306	932
<b>Balance, September 30, 2007</b>	<b>\$ 75,813</b>	<b>\$ 35,472</b>	<b>\$111,285</b>

A reconciliation of the equity component of convertible debentures is provided below:

Balance, December 31, 2006	\$ 1,327
Equity component of 8.25% convertible debentures	2,765
Issue costs incurred	(115)
<b>Balance, September 30, 2007</b>	<b>\$ 3,977</b>

## **Enterra Energy Trust**

### **Notes to Consolidated Financial Statements**

As at September 30, 2007 and for the three and nine months ended September 30, 2007 and 2006

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#### **10. Future Income Taxes**

On October 31, 2006 the Canadian Minister of Finance announced certain changes to the taxation of publicly traded trusts ("Bill C-52"). Bill C-52, the Budget Implementation Act 2007 received its third reading and was substantively enacted on June 12, 2007. Bill C-52 applies to a SIFT trust and will apply a tax at the trust level on distributions of certain income from such SIFT trust at a rate of tax comparable to the combined federal and provincial corporate tax rate. These distributions will be treated as dividends to the trust unitholders. The Trust constitutes a SIFT and as a result, the Trust and its unitholders are subject to Bill C-52.

Bill C-52 applies, commencing January 1, 2007, for all SIFTs that begin to be publicly traded after October 31, 2006 and commencing January 1, 2011 for all SIFTs that were publicly traded on or before October 31, 2006. The Trust anticipates that it will not be subject to the taxation requirements of Bill C-52 until January 1, 2011. Should the Trust raise more than approximately \$165 million of equity during the period from November 1, 2006 to December 31, 2007, the SIFT tax will apply to distributions in 2007. There are similar restrictions in place from 2008 to 2010.

Commencing January 1, 2011, the Trust will become subject to a distribution tax of 31.5 percent on distributions of income. The tax will not apply to returns of capital. As Bill C-52 is implemented, the Trust is required to recognize, on a prospective basis, future income taxes on temporary differences in the Trust. As a result a \$9.9 million reduction of the future income tax liability has been recorded in Q2 2007.

#### **11. Non-controlling Interest**

During Q1 2007, all remaining Enterra Energy Corp. ("EEC") exchangeable shares (16,337) were converted into 23,401 trust units at an exchange ratio prevailing at the time of conversion and all remaining RMAC series B exchangeable shares (66,720) were converted into 81,028 trust units at an exchange ratio prevailing at the time of conversion. The exchange of the EEC exchangeable shares is treated as a step acquisition which increases goodwill by \$0.2 million for the difference between the fair value of the trust unit issued and the carrying value of the EEC exchangeable share at the time of exchange.

**Enterra Energy Trust****Notes to Consolidated Financial Statements**

As at September 30, 2007 and for the three and nine months ended September 30, 2007 and 2006

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(unaudited)***12. Unitholders' Equity****Authorized trust units**

An unlimited number of trust units may be issued.

The trust units are redeemable at the option of the holder based on the lesser of 90% of the average market price of the trust units for the 10 trading days after the date of redemption or the closing market price of the trust units on the date of redemption. Trust units can be redeemed to a cash limit of \$100,000 per year or a greater limit at the discretion of the Trust. Redemptions in excess of the cash limit shall be satisfied first by the issuance of notes by a subsidiary of the Trust and second by issuance of promissory notes by the Trust.

**Issued trust units**

	Number of Units	Amount
Balance at December 31, 2006	56,097,875	\$ 635,134
Issued for cash pursuant to prospectus offering	<b>4,945,000</b>	<b>29,176</b>
Issued as financing fees related to the retirement of the 2006 bridge credit facilities	<b>50,000</b>	<b>515</b>
Issued for exchangeable shares	<b>104,429</b>	<b>1,940</b>
Issued under restricted unit plan	<b>234,802</b>	<b>2,657</b>
Unit issue costs		<b>(1,738)</b>
<b>Balance at September 30, 2007</b>	<b>61,432,106</b>	<b>\$ 667,684</b>

**Contributed surplus**

Balance at December 31, 2006	\$ 3,195
Trust unit option based compensation	<b>970</b>
Restricted and performance unit compensation	<b>1,970</b>
Transfer to trust units on restricted unit exercises	<b>(2,657)</b>
<b>Balance at September 30, 2007</b>	<b>\$ 3,478</b>

## Enterra Energy Trust

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#### Trust unit options

Enterra has granted trust unit options to directors, officers, employees and consultants of the Trust. Each trust unit option permits the holder to purchase one trust unit at the stated exercise price. All options vest over a 3-year period and have a term of 5 years. At the time of grant, the exercise price is equal to the market price.

The following options have been granted:

	2007	
	Number of options	Weighted-average exercise price
Options outstanding, December 31, 2006	1,481,000	\$20.28
Options granted	<b>35,000</b>	<b>15.33</b>
Options forfeited	<b>(131,666)</b>	<b>18.50</b>
Options outstanding, September 30, 2007	<b>1,384,334</b>	<b>\$20.29</b>
Options exercisable at September 30, 2007	<b>660,331</b>	<b>\$21.22</b>

#### Estimated fair value of stock options

The estimated fair value of options granted in 2007 was determined using the Black-Scholes model under the following assumptions:

	2007
Weighted-average fair value of options granted (\$/option)	\$0.28
Risk-free interest rate (%)	5%
Estimated hold period prior to exercise (years)	5
Expected volatility (%)	48%
Expected cash distribution yield (%)	12%
Forfeiture rate (%)	10%

#### Restricted and Performance units

The Trust has granted restricted and performance units to directors, officers and employees of the Trust. Restricted units ("RU's") vest over a contracted period and provide the holder with trust units on the vesting dates of the RU's. The actual number of units granted is based on the number of restricted units granted times a multiplier. The multiplier starts at 1.0 and is adjusted each month based on the monthly distribution of the Trust divided by the five day weighted average price of the Trust's units on the New York Stock Exchange for the period preceding the distribution date. Performance units ("PU's") vest at the end of two years and provide the holder with trust units based on the same multiplier as the RU's as well as a payout multiplier. The payout multiplier ranges between 0.0 and 2.0 based on the Trust's total unitholder return compared to its peers. As at September 30, 2007 the payout multiplier was estimated to be nil based on the Trust's total unitholder return compared to its peers.

**Enterra Energy Trust****Notes to Consolidated Financial Statements**

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The following restricted and performance units have been granted:

	Number of restricted units	Weighted- average grant date fair value	Number of performance units	Weighted- average grant date fair value
Units outstanding, December 31, 2006	423,855	\$14.91	212,948	\$15.41
Granted	<b>277,465</b>	<b>6.66</b>	<b>106,553</b>	<b>5.79</b>
Vested	<b>(212,031)</b>	<b>12.81</b>	-	-
Forfeited	<b>(68,805)</b>	<b>13.14</b>	<b>(56,660)</b>	<b>13.26</b>
<b>Units outstanding, September 30, 2007</b>	<b>420,484</b>	<b>\$10.79</b>	<b>262,841</b>	<b>\$11.89</b>

**Reconciliation of earnings (loss) per unit calculations****For the three months ended September 30, 2007**

	Net loss	Weighted Average Units Outstanding	Per Unit
Basic and diluted	<b>\$(47,681)</b>	<b>61,420,789</b>	<b>\$ (0.78)</b>

For the calculation of the weighted average number of diluted units outstanding for the three months ended September 30, 2007, all convertible debentures, options, restricted and performance units and warrants were excluded, as they were anti-dilutive to the calculation.

**For the nine months ended September 30, 2007**

	Net loss	Weighted Average Units Outstanding	Per Unit
Basic and diluted	<b>\$(102,553)</b>	<b>59,204,965</b>	<b>\$ (1.73)</b>

For the calculation of the weighted average number of diluted units outstanding for the nine months ended September 30, 2007, all convertible debentures, options, restricted and performance units, and warrants were excluded, as they were anti-dilutive to the calculation.

**Enterra Energy Trust****Notes to Consolidated Financial Statements**

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*(Tabular amounts are thousands of Canadian dollars, except trust unit and per trust unit amounts)  
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For the three months ended September 30, 2006			
	Net Earnings	Weighted Average Units Outstanding	Per Unit
Basic	\$ 3,000	44,815,633	\$ 0.07
Exchangeable shares / Non-controlling interest	6	139,200	
Restricted and performance units assumed exercised		612,561	
Diluted	\$ 3,006	45,567,394	\$ 0.07

For the calculation of the weighted average number of diluted units outstanding for the three months ended September 30, 2006, all options and warrants were excluded, as they were anti-dilutive to the calculation.

For the nine months ended September 30, 2006			
	Net earnings	Weighted Average Units Outstanding	Per Unit
Basic	\$ 4,951	42,364,523	\$ 0.12
Exchangeable shares / Non-controlling interest	65	807,876	
Restricted and performance units assumed exercised		612,561	
Options assumed exercised		435,000	
Units assumed purchased		(399,509)	
Diluted	\$ 5,016	43,820,451	\$ 0.11

For the calculation of the weighted average number of diluted units outstanding for the nine months ended September 30, 2006, 1,097,673 options and 301,000 warrants were excluded, as they were anti-dilutive to the calculation.

**13. Accumulated Other Comprehensive Income (Loss)**

Opening balance on adoption of new accounting standards on January 1, 2007 (see note 2)	\$ 1,930
Cumulative translation of self-sustaining operations	(47,869)
Foreign exchange loss realized	1,121
<b>Balance at September 30, 2007</b>	<b>(44,818)</b>

Accumulated other comprehensive income is comprised entirely of currency translation adjustments on the Trust's U.S. operations.

## Enterra Energy Trust

### Notes to Consolidated Financial Statements

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#### 14. Derivative Instruments

The Trust has entered into derivative financial instruments and fixed price physical contracts to minimize the exposure to fluctuations in crude oil and natural gas prices. At September 30, 2007, the Trust had the following financial derivatives and fixed price contracts outstanding:

Derivative Instrument	Commodity	Price	Volume (per day)	Period
Collar	Gas	8.00 by 12.00 (Cdn\$/GJ)	10,000 GJ	November 1, 2007 – March 31, 2008
Floor	Gas	8.00 (US\$/mmbtu)	10,000 mmbtu	November 1, 2007 – March 31, 2008
Collar	Gas	7.00 by 11.00 (US\$/mmbtu)	3,000 mmbtu	November 1, 2007 – March 31, 2008
Fixed	Gas	7.95 (US\$/mmbtu)	2,000 mmbtu	April 1, 2008 – October 31, 2008
Collar	Gas	6.50 by 10.50 (US\$/mmbtu)	3,000 mmbtu	April 1, 2008 – October 31, 2008
Collar	Oil	55.00 by 80.50 (US\$/bbl)	1,000 bbl	October 1, 2007 – December 31, 2007
Collar	Oil	55.00 by 80.50 (US\$/bbl)	1,000 bbl	October 1, 2007 – December 31, 2007
Collar	Oil	55.00 by 78.60 (US\$/bbl)	500 bbl	October 1, 2007 – December 31, 2007
Collar	Oil	55.00 by 75.25 (US\$/bbl)	500 bbl	January 1, 2008 – June 30, 2008
Collar	Oil	62.00 by 78.00 (US\$/bbl)	500 bbl	January 1, 2008 – June 30, 2008
Collar	Oil	62.00 by 75.50 (US\$/bbl)	500 bbl	January 1, 2008 – March 31, 2008
Collar	Oil	62.00 by 75.60 (US\$/bbl)	500 bbl	April 1, 2008 – June 30, 2008
Collar	Oil	62.00 by 80.50 (US\$/bbl)	500 bbl	July 1, 2008 – December 31, 2008
Collar	Oil	62.00 by 80.05 (US\$/bbl)	500 bbl	July 1, 2008 – December 31, 2008
Fixed purchase	Power (Alberta)	62.90 (Cdn \$/Mwh)	72 Mwh	October 1, 2007 – December 31, 2009

At September 30, 2007 the estimated fair market value of the Trust's derivative instruments are as follows:

	Assets	Liabilities
Financial instruments	\$3,693	\$900
Physical power purchase contracts	1,184	-
<b>Derivative instruments, September 30, 2007</b>	<b>\$4,877</b>	<b>\$900</b>

## Enterra Energy Trust

### Notes to Consolidated Financial Statements

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#### 15. Segmented Information

The Trust has one operating segment that is divided amongst two geographical areas. The following is selected financial information from the two geographic areas.

	<b>Three months ended September 30, 2007</b>	Three months ended September 30, 2006	<b>Nine months ended September 30, 2007</b>	Nine months ended September 30, 2006
Oil and natural gas revenue				
Canada	\$ 35,829	\$ 46,638	\$ 99,620	\$ 125,490
U.S.	19,856	26,697	62,946	62,875
	<b>\$ 55,685</b>	<b>\$ 73,335</b>	<b>\$ 162,566</b>	<b>\$ 188,365</b>
Property, plant and equipment				
Canada			\$ 364,684	\$ 398,419
U.S.			252,654	333,018
			<b>\$ 617,338</b>	<b>\$ 731,437</b>
Goodwill				
Canada			-	\$ 76,256
			-	\$ 76,256

#### 16. Related Parties

During Q3 2007 and the nine months ended September 30, 2007, the Trust paid \$126,000 and \$625,000 respectively (Q3 2006 - \$120,000 and nine months ended Q3 2006 - \$415,000) to Macon Resources Ltd. ("Macon"), a company 100% owned by the Chief Executive Officer of the Trust, for management services provided by the Chief Executive Officer and a former Chief Financial Officer. The Trust provides office space, at no additional charge, for Macon and its employees. The amounts have been recorded at the amounts agreed to by the related parties. At September 30, 2007 \$44,000 (December 31, 2006 - \$nil) was payable by the Trust to Macon. In addition, during Q1 2007, the Trust granted 50,000 restricted units (valued at \$422,000 based on the unit price of trust units on the grant date) to Macon. On February 28, 2007, those restricted units vested and were converted into 50,441 trust units.

During 2006, the Trust entered into a farmout agreement with Petroflow Energy Ltd. ("Petroflow"), a public oil and gas company, to fund 100% of the drilling and completion costs of the Trust's undeveloped lands in Oklahoma. The Chief Executive Officer of the Trust owns, directly and indirectly, approximately 14% of the outstanding shares of Petroflow. As at September 30, 2007, the Trust had US\$2.4 million of trade receivables and US\$3.8 million of long term receivables from Petroflow (of which US\$1.4 million is due within one year and classified as current). The trade receivables relate to costs incurred by the Trust as a result of the operations of the properties. The long term receivables are for infrastructure costs that the Trust incurred which are to be repaid by Petroflow to the Trust over a three year period and accrue interest at 12% per annum. During Q3 2007, the Trust earned \$0.2 million of interest income on the long term receivables from Petroflow (nine months ended September 30, 2007 - \$0.3 million).

A former officer of the Trust has working interests in certain of the Oklahoma Assets. Balances will be payable or receivable from the former officer as a result of the operations of these properties. At September 30, 2007 no amounts were payable or receivable from the former officer. Subsequent to September 30, 2007 the officer is no longer an employee of the Trust.

**Enterra Energy Trust****Notes to Consolidated Financial Statements**

As at September 30, 2007 and for the three and nine months ended September 30, 2007 and 2006  
*(Tabular amounts are thousands of Canadian dollars, except trust unit and per trust unit amounts)*  
*(unaudited)*

**17. Subsequent Event**

On November 6, 2007 a notice of intent to make a claim was made against the Trust by a former employee for constructive dismissal. The Trust does not believe the claim has merit.