



ENERGY TRUST
Enterra

Q2

2007 QUARTERLY REPORT TO
THE UNITHOLDERS

Six months ended June 30, 2007

ENTERRA ENERGY TRUST

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is Management's Discussion and Analysis ("MD&A") of Enterra Energy Trust ("the Trust" or "Enterra") for the six-month period ended June 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 six-month period ended June 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 July 31, 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 Q2 2007 of 12,874 boe/day, which was comprised of approximately 63% natural gas and 37% crude oil and natural gas liquids.

The Trust strives to make monthly cash distributions to its unitholders based on a target payout ratio range of 60% to 70% of funds from operations. The Trust’s distributions in Q2 2007 were approximately 62% of funds from operations. While the Trust believes it is important to deliver sustainable and predictable distributions to its unitholders, 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. The Trust will continue to monitor its payout ratio to ensure that, over the medium and long term, the ratio remains in the target range. The Trust is also dependant on obtaining refinancing of its \$55 million second-lien credit facility in November 2007, or distributions may be suspended by the Trust’s lender.

ENTERRA’S GOAL, BUSINESS STRATEGY AND OPERATING PRINCIPLES

Enterra’s goal is to generate returns for its unitholders through a combination of cash distributions that are predictable, sustainable and increase over time, and capital appreciation 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 a distribution level of 60% to 70% of funds from operations to unitholders and to invest the balance 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 distributions. 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;
- moving towards a conservative balance sheet with a target ratio of total net debt (defined as bank indebtedness less current assets plus current liabilities) to funds from operations of 1:1, so that Enterra is positioned to capitalize on acquisition opportunities when they arise; 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 distributions 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’s 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 Q2 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 June, brought the Trust’s distribution ratio to 62% of funds from operations for Q2 2007 compared to 96% for Q2 2006 and to 76% for year to date Q2 2007 compared to 97% for the year to date 2006.

Average production decreased by 10% to 12,874 boe/day in Q2 2007 from 14,339 boe/day in Q2 2006. The Trust exited the quarter with sales volumes of approximately 13,338 boe/day, 3% lower than the Q2 2006 exit rate of 13,723 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 56% in Q2 2007 to \$12.83/boe compared to \$8.22/boe in Q2 2006. Cash G&A expenses increased by 44% in Q2 2007 to an average of \$4.56/boe from \$3.17/boe in Q2 2006. Interest expenses declined in Q2 2007, due to the combined effect of lower average borrowings and a lower average interest rate, decreasing 28% to \$5.7 million in Q2 2007 compared to \$7.8 million in Q2 2006. As a result, funds from operations decreased by 31% to \$19.2 million in Q2 2007 from \$27.7 million in Q2 2006.

The Trust realized net earnings of \$0.13/unit compared to a net loss of \$0.01/unit in Q2 2006.

Over the course of Q2 2007, the Trust paid distributions of \$11.9 million to unitholders or US\$0.18/unit, representing decreases of 55% and 67% respectively, compared to total distributions of \$26.7 million and distributions of US\$0.54/unit in Q2 2006.

On November 20, 2007, the Trust’s \$55 million second-lien credit facility matures. It is expected that the second-lien facility will not be repaid from internally generated cash flows, therefore additional financing through the issuance of debt or equity or asset dispositions will be required. See the liquidity and capital resources section of this MD&A for further discussion on the facility.

	Three months ended June 30,			Six months ended June 30,		
	2007	2006	Change	2007	2006	Change
Revenues	\$62,871	\$67,313	(7%)	\$106,881	\$115,030	(7%)
Average sales (boe/day)	12,874	14,339	(10%)	12,368	12,214	1%
Exit sales rate (boe/day)	13,338	13,723	(3%)	13,338	13,723	(3%)
Cash provided by operating activities	\$19,761	\$34,416	(43%)	\$42,518	\$26,630	60%
Funds from operations ⁽¹⁾	\$19,192	\$27,695	(31%)	\$37,157	\$51,280	(28%)
Net earnings (loss)	\$7,878	\$(296)	2,790%	\$(54,872)	\$1,952	(2,911%)
Net earnings (loss) per trust unit - basic	\$0.13	\$(0.01)	1,400%	\$(0.94)	\$0.05	(1,980%)
Weighted average number of trust units outstanding - basic	59,906	44,005	36%	58,079	41,119	41%
Average price per barrel of oil	\$60.29	\$69.17	(13%)	\$59.02	\$62.86	(6%)
Average price per mcf of natural gas	\$7.37	\$6.77	9%	\$7.61	\$7.35	4%
Production expenses per boe	\$12.83	\$8.22	56%	\$13.67	\$8.62	59%
Netback ⁽²⁾ per boe	\$17.08	\$21.82	(22%)	\$16.86	\$24.36	(31%)

(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	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Revenues	\$62,871	\$44,010	\$56,043	\$73,335	\$67,313	\$47,717	\$50,602	\$47,638
Earnings (loss) before taxes and non-controlling interest	\$(8,173)	\$(72,968)	\$(101,242)	\$(6,879)	\$(10,579)	\$(3,149)	\$(28,526)	\$7,530
Net earnings (loss)	\$7,878	\$(62,752)	\$(69,189)	\$3,000	\$(296)	\$2,248	\$(12,937)	\$7,089
Net earnings (loss) per unit								
Basic	\$0.13	\$(1.12)	\$(1.40)	\$0.07	\$(0.01)	\$0.06	\$(0.37)	\$0.23
Diluted	\$0.13	\$(1.12)	\$(1.40)	\$0.07	\$(0.01)	\$0.06	\$(0.37)	\$0.23
Distributions declared per unit (US\$)	\$0.18	\$0.18	\$0.36	\$0.36	\$0.54	\$0.54	\$0.52	\$0.49

Prior to Q4 2006, the Trust had realized steady growth in revenues for six quarters. The decreases in revenues in 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. Q2 2007 realized an increase in revenues with the increased production from the Trigger Resources acquisition. The growth and subsequent decreases in distributions over the same 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 and to live within its means. The significant net losses in 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 Q2 2007 decreased by 10% to 12,874 boe/day from 14,339 boe/day in Q2 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 Q2 2007 consisted of 4,788 bbls/day of oil and natural gas liquids ("NGL") and 48,514 mcf/day of natural gas, resulting in a mix of 37% oil and NGL and 63% natural gas. As at June 30, 2007, the Trust had an exit production rate of approximately 13,338 boe/day.

In total in Q2 2007, the Trust participated in the drilling of 9 (5.4 net) development wells. For the six months ended June 30, 2007, the Trust participated in the drilling of 13 (6.6 net) development wells. The drilling in Canada and Oklahoma resulted in an overall success rate of 100%.

Canadian Operations

Production in Canada for Q2 2007 declined by 1% to 7,528 boe/day compared to 7,628 boe/day in Q2 2006. The decrease is attributable to normal production declines for the Trust's Canadian properties, offset by the acquisition of Trigger Resources on April 30, 2007, which added 1,166 boe/day to the Q2 average production. Natural gas represented approximately 46% of total production in Q2 2007 versus 42% in Q2 2006. The Q2 2007 exit rate for Canada was approximately 8,215 boe/day.

Consistent with the Trust's strategy of pursuing organic growth opportunities, the Trust continued drilling operations during the quarter. In May with the acquisition of Trigger Resources, came the opportunity for the Trust to drill 3 (3 net) development wells and 1 (1 net) exploration well in the Primate area in western Saskatchewan. The result was two oil wells and two gas wells. Both oil wells were on production shortly after drilling. The gas wells are expected to be on-line in August. The Trust also participated in 1 (0.5 net) non-operated well. 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 5,346 boe/day during Q2 2007 compared to 6,711 boe/day in Q2 2006, of which 87% was natural gas. Most of the decrease in Q2 2007 was due to natural declines. However, the weather in Oklahoma was unseasonably wet with storms causing electrical outages that resulted in lost production. During Q2 2007 four wells that were drilled in the later part of 2006 came on production, along with one well drilled during Q1 2007, and brought the Trust's Q2 2007 exit rate from its U.S. operations to approximately 5,123 boe/day.

In total, the Trust participated in the drilling of 4 (0.9 net) wells in the U.S. in Q2 2007. Of those wells, 2 (0.4 net) were completed during the quarter and the other 2 (0.5 net) wells were still being drilled at June 30, 2007. In addition there were 2 (0.5 net) wells completed that were drilled in Q1 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 June 30,			Six Months ended June 30,		
	2007	2006	Change	2007	2006	Change
Daily Sales Volumes – Average						
Oil & NGL (bbls/day)	4,788	5,242	(9%)	4,692	5,256	(11%)
Natural gas (mcf/day)	48,514	54,582	(11%)	46,057	41,748	10%
Total (boe/day)	12,874	14,339	(10%)	12,368	12,214	1%

Daily Sales Volumes - Exit Rate

Oil & NGL (bbls/day)	4,966	5,187	(4%)	4,966	5,187	(4%)
Natural gas (mcf/day)	50,232	51,213	(2%)	50,232	51,213	(2%)
Total (boe/day)	13,338	13,723	(3%)	13,338	13,723	(3%)

Sales Volumes mix by product

Oil & NGL	37%	37%	38%	43%
Natural gas	63%	63%	62%	57%
	100%	100%	100%	100%

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

	Three Months ended June 30, 2007		Six Months ended June 30, 2007	
	Canada	U.S.	Canada	U.S.
Daily Sales Volumes – Average				
Oil & NGL (bbls/day)	4,085	703	3,965	727
Natural gas (mcf/day)	20,659	27,855	18,870	27,187
Total (boe/day)	7,528	5,346	7,110	5,258

Daily Sales Volumes - Exit Rate

Oil & NGL (bbls/day)	4,375	591	4,375	591
Natural gas (mcf/day)	23,040	27,192	23,040	27,192
Total (boe/day)	8,215	5,123	8,215	5,123

Sales Volumes mix by product

Oil & NGL	54%	13%	56%	14%
Natural gas	46%	87%	44%	86%
	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 increased US\$0.74/mmbtu or 11%, from Q2 2006, averaging US\$7.56/mmbtu in Q2 2007. In Canada, AECO pricing was up \$1.06/GJ, or 18%, from Q2 2006 levels, averaging \$7.07/GJ.

U.S. oil prices decreased 8% from Q2 2006, averaging US\$65.03/bbl in Q2 2007. The effect of the decrease was compounded by a 2% weakening of the U.S. dollar against the Canadian dollar, with the exchange rate rising to an average of US\$0.91 per Canadian dollar in Q2 2007 from an average of US\$0.89 in Q2 2006.

The Q2 2007 average price received by the Trust for oil was down 13% to \$60.29/bbl from \$69.17/bbl in Q2 2006. The Q2 2007 average price received by the Trust for natural gas was up 9% to \$7.37/mcf from \$6.77/mcf in Q2 2006. The Trust received an additional \$0.10/mcf in Q2 2007 from its natural gas commodity contracts compared to an additional \$0.68/mcf in Q2 2006.

Pricing (in thousands except for volumes and pricing)

	Three Months ended June 30,			Six Months ended June 30,		
	2007	2006	Change	2007	2006	Change
Pricing Benchmarks						
WTI (US\$/bbl)	65.03	70.70	(8%)	61.65	67.09	(8%)
Average exchange rate: US\$ to Cdn\$1.00	0.91	0.89	2%	0.88	0.88	-
WTI (Cdn\$/bbl)	71.46	79.44	(10%)	70.06	76.24	(8%)
AECO monthly index (Cdn\$/GJ)	7.07	6.01	18%	7.24	6.78	7%
Nymex (US\$/mmbtu)	7.56	6.82	11%	7.26	7.95	(9%)
Average Prices Received by the Trust						
Oil (Cdn\$ per bbl)	60.29	69.83	(14%)	59.00	63.19	(7%)
Natural gas (Cdn\$ per mcf)	7.27	6.09	19%	7.40	6.55	13%
Oil commodity contract settlements (Cdn\$ per bbl)	-	(0.66)	-	0.02	(0.33)	(106%)
Natural gas commodity contract settlements (Cdn\$ per mcf)	0.10	0.68	(85%)	0.21	0.81	(74%)
Combined Oil (Cdn\$ per bbl)	60.29	69.17	(13%)	59.02	62.86	(6%)
Combined Natural gas (Cdn\$ per mcf)	7.37	6.77	9%	7.61	7.35	4%
Total ⁽¹⁾ (Cdn\$ per boe)	50.06	50.53	(1%)	50.52	51.68	(2%)

(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 increase in oil and natural gas revenues of \$4.2 million in Q2 2007, compared to a non-cash increase in oil and natural gas revenue of \$1.4 million in Q2 2006.

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

Derivative Instrument	Commodity	Price	Volume (per day)	Period
Collar	Gas	7.50 by 9.00 (Cdn\$/GJ)	10,000 GJ	July 1, 2007 – October 31, 2007
Collar	Gas	8.00 by 12.00 (Cdn\$/GJ)	10,000 GJ	November 1, 2007 – March 31, 2008
Floor	Gas	7.50 (US\$/mmbtu)	5,000 mmbtu	July 1, 2007 – October 31, 2007
Fixed sale	Gas	7.555 (US\$/mmbtu)	5,000 mmbtu	July 1, 2007 – October 31, 2007
Collar	Gas	7.50 by 11.10 (US\$/mmbtu)	5,000 mmbtu	July 1, 2007 – October 31, 2007
Collar	Gas	8.00 by 16.40 (US\$/mmbtu)	10,000 mmbtu	November 1, 2007 – March 31, 2008
Collar	Oil	55.00 by 80.50 (US\$/bbl)	1,000 bbl	July 1, 2007 – December 31, 2007
Collar	Oil	55.00 by 80.50 (US\$/bbl)	1,000 bbl	July 1, 2007 – December 31, 2007
Collar	Oil	55.00 by 78.60 (US\$/bbl)	500 bbl	July 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	July 1, 2007 – December 31, 2009

Consistent with the Trust's price risk mitigation strategy, these positions represent approximately 46% of the Trust's expected production, before royalties, on a boe/day basis for the balance of fiscal 2007.

Subsequent to June 30, 2007 the Trust entered into the following derivative transactions:

- the Trust repurchased the Nymex natural gas Call Options it had sold under the November 1, 2007 to March 31, 2008 US\$8.00 by US\$16.40/mmbtu per day collar on 10,000 mmbtu per day (the Trust retained the US\$8.00/mmbtu per day floors on 10,000 mmbtu per day under the original transaction);
- the Trust entered into a new US\$7.00 by US\$11.00/mmbtu Nymex collar on 3,000 mmbtu per day for the period November 1, 2007 to March 31, 2008;
- the Trust entered into a Nymex fixed price contract for 2,000 mmbtu per day of natural gas at US\$7.95/mmbtu for the period April 1, 2008 to October 31, 2008; and
- the Trust entered into a new Nymex US\$6.50 by US\$10.50/mmbtu natural gas collar on 3,000 mmbtu per day for the period April 1, 2008 to October 31, 2008.

As at June 30, 2007 the above commodity contracts had a net mark-to-market value of \$6.4 million.

REVENUES

Total oil and natural gas revenues decreased by 7% in Q2 2007 from Q2 2006 largely due to lower production volumes. The decrease in volumes was partially offset by the positive impact of the unrealized mark-to-market gain on the Trust's price risk management program. On a realized basis, revenues from oil, NGL and natural gas decreased by 11% to \$58.6 million in Q2 2007 from \$65.9 million in Q2 2006. Oil and NGL revenues decreased 19% to \$26.1 million in Q2 2007 due to lower production volumes related to natural declines and lower commodity prices received. Natural gas revenues decreased 3% in Q2 2007 to \$32.5 million due to lower production volumes related to natural declines which were partially offset by higher commodity prices received for natural gas.

Revenues (in thousands)	Three Months ended			Six Months ended		
	June 30,			June 30,		
	2007	2006	Change	2007	2006	Change
Revenues						
Oil and NGL	\$26,102	\$32,300	(19%)	\$49,647	\$58,681	(15%)
Natural gas	32,542	33,636	(3%)	63,455	55,570	14%
	58,644	65,936	(11%)	113,102	114,251	(1%)
Unrealized mark-to-market gains (loss) on oil and natural gas derivative instruments	4,227	1,377	207%	(6,221)	779	(899%)
Oil and natural gas revenues	\$62,871	\$67,313	(7%)	\$106,881	\$115,030	(7%)

Revenues by Geographic area (in thousands)	Three Months ended		Six Months ended	
	June 30, 2007		June 30, 2007	
	Canada	U.S.	Canada	U.S.
Revenues				
Oil and NGL	\$21,513	\$4,589	\$40,513	\$9,134
Natural gas	13,967	18,575	25,994	37,461
	35,480	23,164	66,507	46,595
Unrealized mark-to-market gains (loss) on oil and natural gas derivative instruments	2,523	1,704	(2,716)	(3,505)
	\$38,003	\$24,868	\$63,791	\$43,090

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 Q2 2007 compared to Q2 2006 as a result of lower revenues from the sale of oil, NGL and natural gas in the period. Royalties as a percentage of revenues were unchanged at 22% for both Q2 2007 and Q2 2006.

Royalties (in thousands except for percentages and per boe amounts)						
	Three Months ended June 30,			Six Months ended June 30,		
	2007	2006	Change	2007	2006	Change
Royalties	\$13,093	\$14,789	(11%)	\$25,083	\$24,750	1%
As a percentage of oil, NGL and natural gas revenues	22%	22%		22%	22%	
Royalties per boe	\$11.18	\$11.33	(1%)	\$11.20	\$11.20	-

Royalties by Geographic Area (in thousands except for percentages and per boe amounts)				
	Three Months ended June 30, 2007		Six Months ended June 30, 2007	
	Canada	U.S.	Canada	U.S.
Royalties	\$7,132	\$5,961	\$13,343	\$11,740
As a percentage of oil, NGL and natural gas revenues	20%	26%	20%	25%
Royalties per boe	\$10.41	\$12.25	\$10.37	\$12.34

OTHER INCOME

Other revenues for Q2 2007 represents realized gains of \$2.3 million (\$3.5 million for the six months ended June 30, 2007) and mark-to-market losses of \$4.4 million (\$2.3 million for the six months ended June 30, 2007) on the sale of investments in securities owned by the Trust’s U.S. operations.

PRODUCTION EXPENSES

In Q2 2007, operating costs increased 40% over Q2 2006 to \$15.0 million due to a number of items related to the Canadian Operations including the repair and environmental reclamation of four pipeline failures, reallocation of certain transportation fees to operating expense, and a significant reduction in recoveries associated with the gathering and processing of third party production. On a per boe basis, operating costs in Q2 2007 increased 56% to \$12.83/boe compared to \$8.22/boe for Q2 2006.

Canadian Assets

In Canada in Q2 2007, the average operating expense increased by 60% to \$15.44/boe versus \$9.63/boe in Q2 2006. Total operating expenses increased 58% in Q2 2007 to \$10.6 million from \$6.7 million in Q2 2006. While normal production declines and inflationary pressures played a significant role in the increase in operating expenses, the Trust experienced an inordinate number of pipeline failures during late 2006 and early 2007. As a result, significant costs were incurred in the year-to-date, including costs related to environmental reclamation, failure analyses, pipeline system integrity testing, and repair operations. Currently, the Trust is in the process of re-evaluating the pipeline risk assessments completed as part of our Pipeline Integrity Management System with the goal of reducing these types of costs in the future.

U.S. Assets

Operating expenses for the U.S. assets for Q2 2007 increased 38% to \$9.15/boe from \$6.62/boe in Q2 2006 or \$4.5 million in Q2 2007 compared to \$4.0 million in Q2 2006. Operating expenses per boe were relatively high for the quarter due to a year-over-year decline in production volumes and higher than usual repairs related to weather problems.

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

	Three Months ended June 30,			Six Months ended June 30,		
	2007	2006	Change	2007	2006	Change
Production expenses	\$15,027	\$10,728	40%	\$30,591	\$19,046	61%
Production expenses per boe	\$12.83	\$8.22	56%	\$13.67	\$8.62	59%

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

	Three Months ended June 30,		Six Months ended June 30,	
	Canada	U.S.	Canada	U.S.
Production expenses	\$10,574	\$4,453	\$20,212	\$10,379
Production expenses per boe	\$15.44	\$9.15	\$15.71	\$10.91

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative (“G&A”) expenses increased by 19% in Q2 2007 to \$6.0 million from \$5.0 million in Q2 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 32% to \$5.14/boe in Q2 2007 compared to \$3.88/boe in Q2 2006. Within G&A, non-cash unit based compensation decreased to \$0.7 million in Q2 2007 from \$0.9 million in Q2 2006. This non-cash unit based compensation includes expenses for both unit option plans and the performance and restricted unit plans.

	Three Months ended June 30,			Six Months ended June 30,		
	2007	2006	Change	2007	2006	Change
G&A expenses – cash	\$5,347	\$4,131	29%	\$10,031	\$6,639	51%
G&A expenses – non cash	675	936	(28%)	2,027	1,232	65%
Total G&A expenses	\$6,022	\$5,067	19%	\$12,058	\$7,871	53%
G&A per boe – cash	\$4.56	\$3.17	44%	\$4.48	\$3.00	49%
G&A per boe – non cash	0.58	0.71	(18%)	0.91	0.56	63%
Total G&A per boe	\$5.14	\$3.88	32%	\$5.39	\$3.56	51%

INTEREST EXPENSE

Interest expense decreased in Q2 2007 compared to Q2 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 Q2 2007 was \$304.3 million or 10% lower than at the end of Q2 2006 and overall bears a lower interest rate than the debt outstanding during Q2 2006. As a result, the Trust expects interest expense to be lower throughout the remainder of 2007 compared to 2006.

	Three Months ended June 30,			Six Months ended June 30,		
	2007	2006	Change	2007	2006	Change
Bank indebtedness, capital lease, and notes payable at end of period	\$193,407	\$336,527		\$193,407	\$336,527	
Convertible debentures	110,888	-		110,888	-	
Total convertible debentures, bank indebtedness, capital lease, and notes payable at end of period	\$304,295	\$336,527		\$304,295	\$336,527	
Cash interest expense on bank indebtedness, capital lease, and notes payable	\$2,995	\$7,813	(62%)	\$5,889	\$9,957	(41%)
Non-cash interest expense on bank indebtedness, capital lease, and notes payable	161	-	-	322	-	-
Cash interest expense on convertible debentures	2,173	-	-	3,757	-	-
Non-cash interest expense on convertible debentures	333	-	-	534	-	-
Total interest expense	\$5,662	\$7,813	(28%)	\$10,502	\$9,957	55%
Cash interest expense per boe on bank indebtedness, capital lease, and notes payable	\$2.56	\$5.99	(57%)	\$2.63	\$4.50	(42%)
Cash interest expense per boe on convertible debentures	1.85	-	-	1.68	-	-
Total cash interest expense per boe	\$4.41	\$5.99	(26%)	\$4.31	\$4.50	(4%)

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

DD&A expense decreased by 11% in Q2 2007 to \$31.6 million compared to \$35.4 million in Q2 2006 due to the lower production levels of the Trust in Q2 2007. DD&A expense per boe, increased slightly to \$28.71/boe compared to \$27.10/boe in Q2 2006, due to the acquisition of Trigger Resources and its corresponding depletion.

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.

	Depletion, Depreciation and Accretion <i>(in thousands except for percentages and per boe amounts)</i>					
	Three Months ended			Six Months ended		
	June 30,			June 30,		
	2007	2006	Change	2007	2006	Change
DD&A – excluding write down	\$31,632	\$35,356	(11%)	\$60,426	\$62,615	(3%)
Ceiling test provision	-	-	-	2,111	-	-
DD&A	\$31,632	\$35,356	(11%)	\$62,537	\$62,615	-
DD&A per boe – excluding impairment per boe	\$27.00	\$27.10	-	\$26.99	\$28.32	(5%)
Ceiling test impairment per boe	-	-	-	\$0.94	-	-
DD&A per boe	\$27.00	\$27.10	-	\$27.93	\$28.32	(1%)

GOODWILL IMPAIRMENT

During Q1 2007, the Trust recorded a \$49.3 million impairment on the carrying balance of goodwill in the Canada cost center.

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 distributable cash 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 proposed changes to the taxation of publicly traded trusts (“October 31 Proposals”). Bill C-52, the Budget Implementation Act 2007 received its third reading and was substantively enacted on June 12, 2007. The October 31 Proposal will apply 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 the October 31 Proposals.

The October 31 Proposals are to apply 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. It is expected that the Trust will not be subject to the October 31 Proposals 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. As the October 31 Proposals are implemented, the Trust is required to recognize, on a prospective basis, future income taxes on temporary differences in the Trust. As at June 30, 2007, a \$9.9 million reduction of the future income tax liability has been recorded.

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. Due to the resource properties being in the province of Saskatchewan, there are capital taxes related to the resource assets.

NETBACK PER BOE

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

Netback per boe	Three Months ended June 30,			Six Months ended June 30,		
	2007	2006	Change	2007	2006	Change
Price received per boe (prior to unrealized MTM)	\$50.06	\$50.53	(1%)	\$50.52	\$51.68	(2%)
Royalties per boe	11.18	11.33	(1%)	11.20	11.20	-
Operating expense per boe	12.83	8.22	56%	13.67	8.62	59%
Operating netback per boe	26.05	30.98	(16%)	25.65	31.86	(19%)
Cash G&A per boe	4.56	3.17	44%	4.48	3.00	49%
Cash interest expense per boe	4.41	5.99	(26%)	4.31	4.50	(4%)
Netback per boe	\$17.08	\$21.82	(22%)	\$16.86	\$24.36	(31%)

Netback is a non-GAAP financial measure that management uses to measure operating performance. See the non-GAAP financial measures section of the MD&A for a reconciliation of netback to net earnings (loss).

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.

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 net earnings 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 <i>(in thousands)</i>	Three Months ended		Six Months ended	
	June 30,		June 30,	
	2007	2006	2007	2006
Cash provided by operating activities	\$19,761	\$34,416	\$42,518	\$26,630
Changes in non-cash working capital items	(569)	(6,721)	(5,361)	24,650
Funds from operations	\$19,192	\$27,695	\$37,157	\$51,280

In Q2 2007, funds from operations decreased by 31% over Q2 2006. The decrease mainly was due to lower productions volumes, 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.

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 <i>(in thousands, except per boe)</i>	Three Months ended		Six Months ended	
	June 30,		June 30,	
	2007	2006	2007	2006
Net earnings (loss)	\$7,878	\$(296)	\$(54,872)	\$1,952
Income taxes	(16,051)	(10,283)	(26,268)	(15,739)
Foreign exchange gain	(144)	524	(807)	183
Non-controlling interest	-	-	-	59
Ceiling test impairment	-	-	2,111	-
Depletion, depreciation and accretion	31,632	35,356	60,426	62,615
Goodwill impairment	-	-	49,341	-
Non-cash interest expense	494	-	856	-
Amortization of deferred financing fees	-	3,588	-	3,957
Financing fees	-	27	-	379
Non-cash general and administrative expense	675	936	2,027	1,232
Other income	(248)	-	(1,284)	-
Non-cash revenue	(4,227)	(1,377)	6,221	(779)
Netback	\$20,009	\$28,475	\$37,751	\$53,859
Total boe	1,172	1,305	2,239	2,211
Netback per boe	\$17.08	\$21.82	\$16.86	\$24.36

CASH DISTRIBUTIONS PAID TO UNITHOLDERS

The Trust pays monthly cash distributions to its unitholders in US dollars. Cash distributions are paid on the 15th of the following month or the next business day if the 15th of the month falls on a weekend or a statutory holiday (for example, the June 2007 distribution was paid on July 16, 2007). These distributions are 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 January 19, 2007, due to significantly weaker commodity prices, capital market uncertainty resulting from the tax changes proposed by the Canadian government affecting income trusts, and early conversion of debentures to trust units, the Trust decreased its monthly distribution to US\$0.06 from US\$0.12 per unit.

The Trust continues to monitor the payout ratio to ensure that, over the medium and long term, the ratio remains in the target range of 60% to 70%.

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		\$ 0.12	\$ 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

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

	Three Months ended June 30,			Six Months ended June 30,		
	2007	2006	Change	2007	2006	Change
Funds from operations	\$19,192	\$27,695	(31%)	\$37,157	\$51,280	(28%)
Cash distributions paid to unitholders	11,907	26,689	(55%)	27,746	49,830	(44%)
Capital additions paid with cash (1)	10,056	9,492	6%	20,241	18,288	11%
Funds from operations after cash distributions and capital additions	\$(2,771)	\$(8,486)	(67%)	\$(10,830)	\$(16,838)	(36%)
Cash distributions as a percentage of funds from operations	62%	96%		75%	97%	

(1) Excludes capital additions from acquisitions

The payout ratio in Q2 2007 was 62%, which is within the range of the Trust's target payout ratio of 60% to 70% of funds from operations. During Q2 2007, the Trust's capital additions and cash distributions exceeded funds from operations by \$2.8 million. This excess was largely funded through the Trust's working capital and additional drawings on the Trust's credit facilities.

To the extent that the Trust uses cash to finance capital additions, acquisitions and other significant expenditures, the net cash that is available for distribution to unitholders will be reduced. Hence, the timing and amount of capital expenditures may affect the amount of net cash received by the Trust and, as a consequence, the amount of cash available to distribute to unitholders. Therefore, distributions may be reduced, or even eliminated, at times when significant capital or other expenditures are made with the use of available cash.

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 distributions and thus reduce cash distributions to unitholders.

The Board of Enterra Energy Corp., as administrator of the Trust, has the discretion to determine the extent to which cash provided by operating activities will be allocated to the payment of debt service charges as well as the repayment of outstanding debt. As a consequence, the amount of cash retained to pay debt service charges or reduce debt will reduce the amount of cash available for distribution to unitholders during those periods in which funds are retained by the Trust.

Sustainability of Cash Distributions

(in thousands)

	Previously completed fiscal years			
	Three Months ended June 30, 2007		Six Months ended June 30, 2007	
	2006	2005	2006	2005
Cash provided by operating activities	\$19,761	\$42,518	\$64,485	\$68,120
Net earnings (loss)	\$7,878	\$(54,872)	\$(64,239)	\$970
Cash distributions paid	\$11,907	\$27,746	\$90,487	\$66,195
Excess (shortfall) of cash provided by operating activities over cash distributions paid	\$7,854	\$14,772	\$(26,002)	\$1,925
Excess (shortfall) of net earnings (loss) over cash distributions paid	\$(4,029)	\$(82,618)	\$(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 available excess cash in activities that would allow it to replace produced reserves and offset natural production declines and thus sustain distributions.

In Q2 2007 cash distributions were \$7.9 million less than the cash provided by operating activities and \$4.0 million greater than net earnings. At the current level of distributions, without regard to the other internal and external factors that may affect the amount of cash generated and distributed by the Trust, in order not to erode economic value, the Trust will need to replace produced reserves at a cost that is lower than its historical rates .

The Trust is dependant on obtaining refinancing of its \$55 million second-lien credit facility in November 2007, or distributions may be suspended by the Trust's lender.

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.

Capital Expenditures Paid with Cash (in thousands except for percentages)	Three Months ended June 30,			Six Months ended June 30,		
	2007	2006	Change	2007	2006	Change
	Capital expenditures	\$73,313	\$60,226	22%	\$83,498	\$194,884

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, 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 six months ended June 30, 2007 in Canada, the Trust spent \$12.4 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, \$4.9 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 \$4.6 million for other plant and equipment. The Trust sold \$1.3 million of non-core assets during the first half of 2007.

During the six months ended June 30, 2007 in the U.S., approximately US\$2.3 million was spent to acquire lands for future development in Oklahoma. In addition, the Trust spent US\$2.7 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 Inc. ("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 Q2 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 for the Trust. Under the Trust's agreement with Petroflow, the Trust will recover the costs of the infrastructure over a three year period. During Q2 2007, the Trust earned \$0.1 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.

The \$40 million second-lien facility, which was increased to a \$55 million facility on July 17, 2007, 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. Until July 17, 2007, borrowings under the second-lien facility bore interest at Canadian dollar Bankers' Acceptance or U.S. dollar LIBOR rates plus a margin of 2.5%, or Canadian or U.S. Prime rates plus a margin of 1.5% depending on the form of borrowing. As at June 30, 2007 all borrowings under the second-lien facility were denominated in Canadian dollars and interest was being accrued at a rate of 6.9% per annum.

On July 17, 2007 the \$40 million non-revolving second-lien credit facility was increased to \$55 million, effective August 3, 2007, to enable the Trust to fund certain short-term working capital requirements in part related to the development of the assets acquired with Trigger Resources. 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. On August 30, 2007 the applicable margin will increase by 1.0%, and by a further 1.0% on September 30, 2007. The facility matures on November 20, 2007.

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 June 30, 2007 all borrowings under the facilities were denominated in Canadian dollars and interest was being accrued at a rate of 5.6% per annum. At June 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 June 30, 2007, the Trust was in compliance with the financial covenants.

In Q3 2007, the lenders will review the Trust's oil and gas reserves and borrowing base. 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. It is not expected that the facilities can be repaid from internally generated cash flows. The options available to the Trust for repaying the facilities include the sale of assets, the issuance of debt and equity and a reduction or elimination of distributions. 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 \$163 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 require the Trust to suspend distributions to Unitholders and demand payment of all outstanding debt. In this event certain accounting adjustments may be required to recorded assets and liabilities.

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>	June 30, 2007	December 31, 2006
Working capital (deficiency)	\$(191,379)	\$(188,683)
Working capital (deficiency) excluding bank debt	\$(1,603)	\$(529)

The working capital deficiencies mainly relate to the classification of the bank indebtedness as current liabilities even though there is no expectation that \$140 million and the \$20 million revolving lines of credit will be called for repayment by the bank.

RELATED PARTY TRANSACTIONS

During Q2 2007 and the six months ended June 30, 2007, the Trust paid \$116,000 and \$499,000 respectively (Q2 2006 - \$145,000 and six months ended Q2 2006 - \$295,000) 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 the previous Chief Financial Officer. The amounts have been recorded at the amounts agreed to by the related parties. At June 30, 2007 \$nil (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 Oklahoma Assets' undeveloped lands. The Chief Executive Officer of the Trust owns, directly and indirectly, approximately 14% of the outstanding shares of Petroflow. As at June 30, 2007, the Trust had US\$3.3 million of trade receivables and US\$2.9 million of long term receivables from Petroflow (of which US\$0.9 million is due within one year and classified as current). The 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 Q2 2007, the Trust earned \$0.1 million of interest income on the long term receivables from Petroflow.

An officer of the Trust has working interests in certain of the Oklahoma Assets. Balances will be payable or receivable from the officer as a result of the operations of these properties. At June 30, 2007 no amounts were payable or receivable from the officer.

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:

Outstanding unit data (<i>units / shares</i>)			
As at	July 30, 2007	June 30, 2007	December 31, 2006
Trust units	61,419,455	61,403,749	56,097,875
Exchangeable shares			
EEC exchangeable shares	-	-	16,337
RMG exchangeable shares	-	-	-
RMAC Series B exchangeable shares	-	-	66,720
Trust unit options	1,451,000	1,451,000	1,481,000
Restricted units	251,839	272,608	423,855
Performance units	200,655	200,655	212,948
Warrants	301,000	301,000	301,000
8.0% Convertible debentures (\$1,000 per debenture)	80,331	80,331	80,331
8.25% Convertible debentures (\$1,000 per debenture)	40,000	40,000	-

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

No material changes were identified in the Trust's internal control of financial reporting during the three months ended June 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, on EDGAR at www.sec.gov/edgar.shtml, as well as on the Trust's website at www.enterraenergy.com.

ABBREVIATIONS

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)
mboe	thousands of barrels of oil equivalent
boe/day	barrels of oil equivalent per day
GJ	Gigajoule
mmbtu	millions of British Thermal Units
CICA	Canadian Institute of Chartered Accountants
GAAP	Canadian Generally Accepted Accounting Principles
Cdn\$	Canadian dollars
US\$	United States dollars
WTI	West Texas Intermediate (Oil reference price)
AECO	Natural gas reference price in Alberta
Nymex	New York Mercantile Exchange
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
mbbl	thousand barrels of oil
mmcf	millions of cubic feet of natural gas per day
mmbtu/day	millions of British Thermal Units per day
Mwh	megawatt-hour

ENTERRA ENERGY TRUST

CONSOLIDATED BALANCE SHEETS

(Thousands of Canadian dollars)

(unaudited)

June 30, 2007

December 31, 2006

Assets

Current assets

Cash	\$ 3,145	\$ 2,162
Accounts receivable	37,977	38,980
Derivatives (note 14)	6,858	10,775
Prepaid expenses, deposits and other	2,081	3,249

	50,061	55,166
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Long term receivable (note 16)	2,100	-
Deferred financing charges	-	4,676
Property, plant and equipment (note 5)	666,184	659,268
Goodwill (note 6)	27,122	76,256

	\$ 745,467	\$ 795,366
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Liabilities

Current liabilities

Bank indebtedness (note 2)	\$ 189,776	\$ 188,154
Accounts payable and accrued liabilities	43,627	46,083
Distribution payable to unitholders	3,918	7,910
Capital lease obligations	1,234	1,702
Note payable (note 7)	2,397	-
Derivatives (note 14)	488	-

	241,440	243,849
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Convertible debentures (note 9)	110,888	78,974
Asset retirement obligations (note 8)	30,682	28,447
Future income tax liability (note 10)	31,368	40,340

	414,378	391,610
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Non-controlling interest (note 11)	-	1,732
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Unitholders' Equity (note 12)

Unitholders' capital	667,400	635,134
Equity component of convertible debentures (note 9)	3,977	1,327
Warrants	1,215	1,215
Contributed surplus	2,849	3,195
Deficit	(318,394)	(240,777)
Accumulated other comprehensive (loss) income (note 13)	(25,958)	1,930

	331,089	402,024
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Bank indebtedness, repayments and the need to refinance (note 2)	\$ 745,467	\$ 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 June 30, 2007	Three months ended June 30, 2006	Six months ended June 30, 2007	Six months ended June 30, 2006
Revenues				
Oil and natural gas	\$ 62,871	\$ 67,313	\$ 106,881	\$ 115,030
Royalties	(13,093)	(14,789)	(25,083)	(24,750)
	49,778	52,524	81,798	90,280
Other income	248	-	1,284	-
	50,026	52,524	83,082	90,280
Expenses				
Operating	15,027	10,728	30,591	19,046
General and administrative	6,022	5,067	12,058	7,871
Interest on bank indebtedness	3,156	7,813	6,211	9,957
Interest on convertible debentures	2,506	-	4,291	-
Financing fees	-	27	-	379
Amortization of deferred financing charges	-	3,588	-	3,957
Depletion, depreciation and accretion	31,632	35,356	60,426	62,615
Ceiling test impairment	-	-	2,111	-
Goodwill impairment	-	-	49,341	-
Foreign exchange (gain) loss	(144)	524	(807)	183
	58,199	63,103	164,222	104,008
Loss before taxes and non-controlling interest	(8,173)	(10,579)	(81,140)	(13,728)
Income taxes				
Current	160	-	208	-
Future (reduction)	(16,211)	(10,283)	(26,476)	(15,739)
Earnings (loss) before non-controlling interest	7,878	(296)	(54,872)	2,011
Non-controlling interest (note 11)	-	-	-	59
Net earnings (loss)	7,878	(296)	(54,872)	1,952
Other comprehensive income (loss)				
Foreign currency translation adjustment	31,353	-	28,386	-
Comprehensive income (loss)	\$ (23,475)	\$ (296)	\$ (83,258)	\$ 1,952
Net earnings (loss) per trust unit (note 12)				
Basic	\$ 0.13	\$ (0.01)	\$ (0.94)	\$ 0.05
Diluted	\$ 0.13	\$ (0.01)	\$ (0.94)	\$ 0.05

CONSOLIDATED STATEMENTS OF DEFICIT

Deficit, beginning of period	\$ (314,344)	\$ (107,952)	\$ (240,777)	\$ (85,840)
Change in accounting policy (note 3)	-	-	1,009	-
Net earnings (loss)	7,878	(296)	(54,872)	1,952
Distributions declared	(11,928)	(26,703)	(23,754)	(51,063)
Deficit, end of period	\$ (318,394)	\$ (134,951)	\$ (318,394)	\$ (134,951)

See accompanying notes to consolidated financial statements

ENTERRA ENERGY TRUST

CONSOLIDATED STATEMENTS OF CASH FLOW

(Expressed in thousand Canadian dollars)

(unaudited)

	Three months ended June 30, 2007	Three months ended June 30, 2006	Six months ended June 30, 2007	Six months ended June 30, 2006
Cash provided by (used in):				
Operating				
Net earnings (loss)	\$ 7,878	\$ (296)	\$ (54,872)	\$ 1,952
Depletion, depreciation, accretion and ceiling test impairment	31,632	35,356	62,537	62,615
Goodwill impairment	-	-	49,341	-
Future income tax reduction	(16,211)	(10,283)	(26,476)	(15,739)
Amortization of deferred financing charges	-	3,588	-	3,957
Financial derivatives	(4,859)	(1,377)	5,677	(779)
Amortization of marketing contracts	-	-	-	(1,447)
Non-controlling interest	-	-	-	59
Foreign exchange	88	(229)	(629)	(570)
Unit-based compensation	675	936	2,027	1,232
Cash paid on settlement of asset retirement obligations	(505)	-	(1,304)	-
Accretion on convertible debentures and amortization of bank fees	494	-	856	-
Changes in non-cash working capital items	569	6,721	5,361	(24,650)
	19,761	34,416	42,518	26,630
Financing				
Distributions paid	(11,907)	(26,689)	(27,746)	(49,830)
Bank indebtedness	4,325	(4,289)	2,748	(99,739)
Bridge credit facilities	-	55,578	-	401,242
Bridge credit facility repayment	-	(2,000)	-	(60,630)
Issuance of convertible debentures (net of \$2,489 issue costs) (note 9)	37,816	-	37,511	-
Issue of trust units, net of issue costs (note 12)	27,809	(64)	27,438	12,259
Exercise of trust unit options	-	1,399	-	1,399
Proceeds from (repayment of) notes	2,397	(3,990)	2,397	(3,990)
Capital lease	(237)	(216)	(468)	(429)
Repayment of debt assumed on Oklahoma Asset acquisition	-	(121)	-	(14,156)
Due to JED Oil Inc., net	-	3,601	-	(6,898)
Deferred financing charges	-	(1,073)	-	(9,410)
	60,203	22,136	41,880	169,818
Investing				
Property, plant and equipment additions	(10,056)	(9,492)	(20,241)	(18,288)
Proceeds on dispositions	1,252	6,551	1,252	6,551
Acquisition of Trigger Resources (note 4)	(63,257)	-	(63,257)	-
Acquisition of Oklahoma Assets	-	(50,734)	-	(176,596)
Proceeds from long term receivable	240	-	240	-
Changes in capital accounts payable	(4,963)	(3,278)	(1,271)	(1,175)
	(76,784)	(56,953)	(83,277)	(189,508)
Change in cash	3,180	(401)	1,121	6,940
Cash, beginning of period	103	19,284	2,162	11,943
Impact of foreign exchange on foreign cash	(138)	-	(138)	-
Cash, end of period	\$ 3,145	\$ 18,883	\$ 3,145	\$ 18,883

During the six month period ended June 30, 2007 the Trust paid interest of \$10,463 (six months ended June 30, 2006 - \$9,922) and taxes of \$213 (six months ended June 30, 2006 - \$nil).

See accompanying notes to consolidated financial statements

Enterra Energy Trust
Notes to Consolidated Financial Statements

As at June 30, 2007 and for the six months ended June 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. Bank indebtedness, repayments and the need to refinance

	June 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	9,562	7,695
Other credit facilities	391	459
Prepaid debt costs	(177)	-
Bank indebtedness	\$ 189,776	\$ 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.

The \$40 million second-lien facility, which was increased to a \$55 million facility on July 17, 2007, 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. Until July 17, 2007, borrowings under the second-lien facility bore interest at Canadian dollar Bankers’ Acceptance or U.S. dollar LIBOR rates plus a margin of 2.5%, or Canadian or U.S. Prime rates plus a margin of 1.5% depending on the form of borrowing. As at June 30, 2007 all borrowings under the second-lien facility were denominated in Canadian dollars and interest was being accrued at a rate of 6.9% per annum.

On July 17, 2007 the \$40 million non-revolving second-lien credit facility was increased to \$55 million, effective August 3, 2007, to enable the Trust to fund certain short-term working capital requirements in part related to the development of the assets acquired with Trigger Resources. 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. On August 30, 2007 the applicable margin will increase by 1.0%, and by a further 1.0% on September 30, 2007. The facility matures on November 20, 2007.

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

Enterra Energy Trust

Notes to Consolidated Financial Statements

As at June 30, 2007 and for the six months ended June 30, 2007 and 2006

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

flow. As at June 30, 2007 all borrowings under the facilities were denominated in Canadian dollars and interest was being accrued at a rate of 5.6% per annum. At June 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 June 30, 2007, the Trust was in compliance with the financial covenants.

In Q3 2007, the lenders will review the Trust's oil and gas reserves and borrowing base. 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. It is not expected that the facilities can be repaid from internally generated cash flows. The options available to the Trust for repaying the facilities include the sale of assets, the issuance of debt and equity and a reduction or elimination of distributions. 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 \$163 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 require the Trust to suspend distributions to Unitholders and demand payment of all outstanding debt. In this event certain accounting adjustments may be required to recorded assets and liabilities.

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 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

Enterra Energy Trust

Notes to Consolidated Financial Statements

As at June 30, 2007 and for the six months ended June 30, 2007 and 2006

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

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.

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

As at June 30, 2007 and for the six months ended June 30, 2007 and 2006

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

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
Assets:			
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>
Liabilities:			
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
Unitholder's Equity			
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

As at June 30, 2007 and for the six months ended June 30, 2007 and 2006

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

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 production, cash flow and reserves. 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:

Allocation of purchase price:	
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

Consideration:	
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 June 30, 2007 and for the six months ended June 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

June 30, 2007			
	Cost	Accumulated depletion and depreciation	Net
Petroleum and natural gas properties	\$1,079,576	\$416,437	\$663,139
Office furniture and equipment	5,233	2,188	3,045
	\$1,084,809	\$418,625	\$666,184
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
	\$1,016,517	\$357,249	\$659,268

During Q2 2007 \$0.4 million of general and administrative expenses were capitalized and included in the cost of the petroleum and natural gas properties (Q2 2006 – \$nil).

At June 30, 2007 costs of undeveloped land of \$39,470,000 (December 31, 2006 - \$25,876,000) were excluded from and \$14,503,000 (December 31, 2006 - \$8,018,000) of future development costs were added to the calculation of depletion expense for the Canadian cost centre. At June 30, 2007 costs of undeveloped land of \$16,621,000 (December 31, 2006 - \$16,848,000) were excluded from and \$3,676,000 (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 June 30, 2007 were \$19,216,000 million and \$11,818,000 million respectively (three months ended June 30, 2006 - \$21,743,000 and \$13,106,000) and for the six months ended June 30, 2007 were \$37,400,000 and \$21,865,000 respectively (Q2 2006 - \$44,743,000 and \$16,878,000).

The Trust completed ceiling test calculations for the Canadian and U.S. cost centers at June 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, the Trust recorded a \$49.3 million impairment on the carrying balance of goodwill in the Canadian reporting unit.

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As at June 30, 2007 and for the six months ended June 30, 2007 and 2006

*(Tabular amounts are thousands of Canadian dollars, except trust unit and per trust unit amounts)
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7. Note Payable

The Trust has a \$2,397,000 (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 is due on October 31, 2007.

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 June 30, 2007, the Trust estimated the asset retirement obligation to be \$30,682,000 (December 31, 2006 - \$28,447,000), based on a total future liability of \$50,988,000 (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		445
Disposals		(73)
Accretion expense		1,161
Costs incurred		(1,304)
Foreign exchange		(568)
Asset retirement obligation, June 30, 2007	\$	30,682

Enterra Energy Trust
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As at June 30, 2007 and for the six months ended June 30, 2007 and 2006

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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 June 30, 2007, the Trust had \$80.3 million in 8% convertible debentures outstanding with an estimated fair value of \$80.3 million and \$40.0 million in 8.25% convertible debentures outstanding with an estimated fair value of \$40.4 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 2)	(3,481)	-	(3,481)
Issue costs	(305)	(2,069)	(2,374)
Accretion of discount	409	125	534
Balance, June 30, 2007	\$ 75,597	\$ 35,291	\$ 110,888

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)
Balance, June 30, 2007	\$ 3,977

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10. Future Income Taxes

On October 31, 2006 the Canadian Minister of Finance announced certain proposed changes to the taxation of publicly traded trusts ("October 31 Proposals"). Bill C-52, the Budget Implementation Act 2007 received its third reading and was substantively enacted on June 12, 2007. The October 31 Proposal will apply 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 the October 31 Proposals.

The October 31 Proposals are to apply 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. It is expected that the Trust will not be subject to the October 31 Proposals 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. As the October 31 Proposals are implemented, the Trust is required to recognize, on a prospective basis, future income taxes on temporary differences in the Trust. As at June 30, 2007, a \$9.9 million reduction of the future income tax liability has been recorded.

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 June 30, 2007 and for the six months ended June 30, 2007 and 2006

*(Tabular amounts are thousands of Canadian dollars, except trust unit and per trust unit amounts)
(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	4,945,000	29,176
Issued as financing fees related to the retirement of the 2006 bridge credit facilities	50,000	515
Issued for exchangeable shares	104,429	1,940
Issued under restricted unit plan	206,445	2,373
Unit issue costs		(1,738)
Balance at June 30, 2007	61,403,749	\$ 667,400

Contributed surplus

Balance at December 31, 2006	\$ 3,195
Trust unit option based compensation	647
Restricted and performance unit compensation	1,380
Transfer to trust units on restricted unit exercises	(2,373)
Balance at June 30, 2007	\$ 2,849

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*(Tabular amounts are thousands of Canadian dollars, except trust unit and per trust unit amounts)
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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	35,000	15.33
Options forfeited	(65,000)	23.66
Options outstanding, June 30, 2007	1,451,000	\$19.98
Options exercisable at June 30, 2007	610,331	\$21.54

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 June 30, 2007 the payout multiplier was estimated to be nil based on the Trust's total unitholder return compared to its peers.

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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	70,990	8.18	12,246	5.27
Vested	(185,882)	13.09	-	-
Forfeited	(36,355)	12.51	(24,539)	13.68
Units outstanding, June 30, 2007	272,608	\$14.68	200,655	\$14.74

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

	Net earnings	Weighted Average Units Outstanding	Per Unit
Basic	\$7,878	59,905,743	\$0.13
Restricted units assumed exercised	-	272,608	
Diluted	\$7,878	60,178,351	\$0.13

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

For the six months ended June 30, 2007

	Net loss	Weighted Average Units Outstanding	Per Unit
Basic and diluted	\$(54,872)	58,078,743	\$(0.94)

For the calculation of the weighted average number of diluted units outstanding for the six months ended June 30, 2007, all options, restricted and performance units, convertible debentures 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 June 30, 2006			
	Net loss	Weighted Average Units Outstanding	Per Unit
Basic and diluted	\$ (296)	44,004,939	\$ (0.01)

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

For the six months ended June 30, 2006			
	Net earnings	Weighted Average Units Outstanding	Per Unit
Basic	\$ 1,952	41,118,656	\$ 0.05
Exchangeable shares / Non-controlling interest	59	1,685,982	
Restricted and performance units assumed exercised		553,585	
Options assumed exercised		437,000	
Units assumed purchased		(375,168)	
Diluted	\$ 2,011	43,420,055	\$ 0.05

For the calculation of the weighted average number of diluted units outstanding for the six months ended June 30, 2006, 1,147,415 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	(28,386)
Foreign exchange loss realized	498
Balance at June 30, 2007	\$ (25,958)

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

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

Derivative Instrument	Commodity	Price	Volume (per day)	Period
Collar	Gas	7.50 by 9.00 (Cdn\$/GJ)	10,000 GJ	July 1, 2007 – October 31, 2007
Collar	Gas	8.00 by 12.00 (Cdn\$/GJ)	10,000 GJ	November 1, 2007 – March 31, 2008
Floor	Gas	7.50 (US\$/mmbtu)	5,000 mmbtu	July 1, 2007 – October 31, 2007
Fixed sale	Gas	7.555 (US\$/mmbtu)	5,000 mmbtu	July 1, 2007 – October 31, 2007
Collar	Gas	7.50 by 11.10 (US\$/mmbtu)	5,000 mmbtu	July 1, 2007 – October 31, 2007
Collar	Gas	8.00 by 16.40 (US\$/mmbtu)	10,000 mmbtu	November 1, 2007 – March 31, 2008
Collar	Oil	55.00 by 80.50 (US\$/bbl)	1,000 bbl	July 1, 2007 – December 31, 2007
Collar	Oil	55.00 by 80.50 (US\$/bbl)	1,000 bbl	July 1, 2007 – December 31, 2007
Collar	Oil	55.00 by 78.60 (US\$/bbl)	500 bbl	July 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	July 1, 2007 – December 31, 2009

Subsequent to June 30, 2007 the Trust entered into the following derivative transactions:

- the Trust repurchased the Nymex natural gas Call Options it had sold under the November 1, 2007 to March 31, 2008 US\$8.00 by US\$16.40/mmbtu per day collar on 10,000 mmbtu per day (the Trust retained the US\$8.00/mmbtu per day floors on 10,000 mmbtu per day under the original transaction);
- the Trust entered into a new US\$7.00 by US\$11.00/mmbtu Nymex collar on 3,000 mmbtu per day for the period November 1, 2007 to March 31, 2008;

Enterra Energy Trust

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- the Trust entered into a Nymex fixed price contract for 2,000 mmbtu per day of natural gas at US\$7.95/mmbtu for the period April 1, 2008 to October 31, 2008; and
- the Trust entered into a new Nymex US\$6.50 by US\$10.50/mmbtu natural gas collar on 3,000 mmbtu per day for the period April 1, 2008 to October 31, 2008.

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

	Assets	Liabilities
Financial instruments	\$ 5,401	\$ 488
Physical power purchase contracts	1,457	-
Derivative instruments, June 30, 2007	\$ 6,858	\$ 488

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.

	Three months ended June 30, 2007	Three months ended June 30, 2006	Six months ended June 30, 2007	Six months ended June 30, 2006
Oil and natural gas revenue				
Canada	\$ 38,003	\$ 39,176	\$ 63,791	\$ 78,852
U.S.	24,868	28,137	43,090	36,178
	\$ 62,871	\$ 67,313	\$ 106,881	\$ 115,030
Property, plant and equipment				
Canada			\$ 386,966	\$ 433,836
U.S.			279,218	329,381
			\$ 666,184	\$ 763,217
Goodwill				
Canada			\$ 27,122	\$ 75,649
			\$ 27,122	\$ 75,649

16. Related Parties

During Q2 2007 and the six months ended June 30, 2007, the Trust paid \$116,000 and \$499,000 respectively (Q2 2006 - \$145,000 and six months ended Q2 2006 - \$295,000) 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 the previous Chief Financial Officer. The amounts have been recorded at the amounts agreed to by the related parties. At June 30, 2007 \$nil (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 Inc. ("Petroflow"), a public oil and gas company, to fund 100% of the drilling and completion costs of the Oklahoma Assets' undeveloped lands. The Chief Executive Officer of the Trust owns, directly and indirectly, approximately 14% of the outstanding shares of Petroflow. As at June 30, 2007, the Trust had US\$3.3

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million of trade receivables and US\$2.9 million of long term receivables from Petroflow (of which US\$0.9 million is due within one year and classified as current). The 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 Q2 2007, the Trust earned \$0.1 million of interest income on the long term receivables from Petroflow.

An officer of the Trust has working interests in certain of the Oklahoma Assets. Balances will be payable or receivable from the officer as a result of the operations of these properties. At June 30, 2007 no amounts were payable or receivable from the officer.