ENTERRA ENERGY TRUST
Form 20-F
June 26, 2009

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 20-F

(Mark One)

REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) OR (g) OF THE SECURITIES EXCHANGE ACT OF 1934.

OR

R ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934.
For the fiscal year ended December 31, 2008.

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934.

OR

SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934.
Date of event requiring this shell company report ……………….

For the transition period from ____________________ to _____________________

Commission file number 000-32115

ENTERRA ENERGY TRUST

(Exact Name of Registrant as Specified in Its Charter)

Alberta, Canada

(Jurisdiction of Incorporation or Organization)

Suite 2700, 500 – 4th Avenue S.W., Calgary, Alberta, Canada T2P 2V6
(Address of Principal Executive Offices)

Blaine Boerchers, Suite 2700, 500 – 4th Avenue S.W., Calgary, Alberta, Canada, T2P 2V6,
Tel: (403) 538-3580, Fax: (403) 294-1197
(Name, Telephone, E-mail and/or Facsimile number and Address of Company Contact Person)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange On Which Registered
Trust Units	New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act:.

Trust Units

(Title of Class)

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Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:

None

(Title of Class)

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

Trust Units, without par value at December 31, 2008: 62,158,987

Indicate by check mark whether if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Exchange Act of 1934.
Yes No R

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.
Yes No R

Note – Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 from their obligations under those Sections.

Indicate by check mark whether if the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes R No

Indicate by check mark whether if the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer Accelerated filer
Non-Accelerated filer R

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:

U.S. GAAP International Financial Reporting Standards as issued by the International Accounting Standards Board Other R

If "Other" has been checked in response to the previous question, indicate by check mark which financial statement item the registrant has elected to follow.
Item 17 R Item 18

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act.
Yes No R

(APPLICABLE ONLY TO ISSUER INVOLVED IN BANKRUPTCY PROCEEDINGS DURING THE PAST FIVE YEARS)

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court
Yes No R

Note Regarding Forward-Looking Statements

Certain information contained herein may contain forward-looking statements including management's assessment of future plans and operations, drilling plans and timing thereof, expected production increases from certain projects and the timing thereof, the effect of government announcements, proposals and legislation, plans regarding wells to be drilled, expected or anticipated production rates, expected exchange rates, distributions and method of funding thereof, proportion of distributions anticipated to be taxable and non-taxable, anticipated borrowing base under credit facility, maintenance of productive capacity and capital expenditures and the nature of capital expenditures and the timing and method of financing thereof, may constitute forward-looking statements under applicable securities laws and necessarily involve risks. All statements other than statements of historical facts contained in this MD&A are forward-looking statements. The words "believe", "may", "will", "estimate", "continue", "anticipate," "intend", "should", "p and similar expressions, as they relate to the Trust, are intended to identify forward-looking statements. The Trust has based these forward-looking statements on the 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 uncertainties, assumptions and a number of risks, including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources. The recovery and reserve estimates of Enterra's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Events or circumstances may cause actual results to differ materially from those predicted, as a result of the risk factors set out and other known and unknown risks, uncertainties, and other factors, many of which are beyond the control of the Trust. In addition to other factors and assumptions which may be identified herein, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which the Trust operates; the timely receipt of any required regulatory approvals; the ability of the Trust to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Trust has an interest in to operate the field in a safe, efficient and effective manner; the ability of the Trust to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisitions, development and exploration; the timing and cost of pipeline, storage and facility construction and expansion and the ability of the Trust to secure adequate reasonably priced transportation; future commodity oil and gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Trust operates; and the ability of the Trust to successfully market its oil and natural gas products. Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which have been used. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Additional information on these and other factors could effect Enterra's operations and financial results are included in reports on file with the Canadian and United States regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), or the EDGAR website (www.sec.gov/edgar.shtml), or at Enterra's website (www.enterraenergy.com). Furthermore, the forward-looking statements contained herein are made as at the date hereof and Enterra does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of the new information, future events or otherwise, except as may be required by applicable securities law. Other sections of this MD&A may include additional factors that could adversely affect the business and financial performance. The Trust operates in a very competitive and rapidly changing business 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 its 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 reader should not rely upon forward-looking statements as predictions of future events or performance. The Trust cannot provide assurance 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.

The reader is further cautioned that the preparation of financial statements in accordance with GAAP requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based upon available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available, and as the economic environment changes.

Glossary

The following are defined terms used in this form 20-F:

“ABCA” means the Business Corporations Act (Alberta);

“Administration Agreement” means an administration agreement dated November 25, 2003 between the Trust and EEC;

“CT Notes” means the unsecured promissory notes issued by EECT to the Trust;

“Debentures” means the 8% and/or the 8.25% convertible unsecured subordinated debentures of the Trust issued under the Debenture Indenture;

“Delaware GCL” means Delaware General Corporation Law;

“EAC” means Enterra Acquisitions Corp., a corporation incorporated under the Delaware GCL and an indirect subsidiary of the Trust;

“EEC” means Enterra Energy Corp., a corporation incorporated under the ABCA, a wholly-owned subsidiary of the Trust, and administrator of the Trust pursuant to the Administration Agreement;

“EEC Exchangeable Shares” means shares of EEC that were exchangeable for Trust Units;

“EECT” means Enterra Energy Commercial Trust, an unincorporated trust governed by the laws of Alberta and a wholly owned subsidiary of the Trust;

“EECT Units” means trust units of EECT;

“EEPC” means Enterra Energy Partner Corp., a corporation incorporated under the ABCA. EEPC is a holding company wholly owned by EEC which holds an interest in EPP;

“Enterra Arrangement” means the plan of arrangement completed on November 25, 2003 involving the Trust, EECT, Old Enterra and its subsidiaries, and Enterra Acquisition Corp.;

“Enterra US Acqco” means Enterra US Acquisitions Inc., a corporation incorporated under the Delaware GCL and an indirect subsidiary of the Trust;

“EPC” means Enterra Production Corp., a corporation incorporated under the ABCA and was a wholly-owned subsidiary of the Trust prior to January 31, 2007;

“EPP” means the Enterra Production Partnership, a partnership organized pursuant to the laws of Alberta;

“Exchangeco” means Enterra Exchangeco Ltd., a corporation incorporated under the ABCA and a wholly-owned subsidiary of EECT;
“GAAP” means generally accepted accounting and principles in Canada;

“Haas” means Haas Petroleum Engineering Services, Inc., independent petroleum engineering consultants;

“Haas Report” means the independent engineering evaluation of certain oil, NGL and natural gas interests of the Trust prepared by Haas dated March 5, 2009 and effective January 1, 2009;

“High Point” means High Point Resources Inc., a corporation incorporated under the ABCA;

“JED” means JED Oil Inc., a corporation incorporated under the ABCA;

“JED Swap” means the exchange, completed on September 28, 2006 with an effective date of July 1, 2006, of the Trust’s interests in certain properties for interests held by JED and the settlement of certain indebtedness owed to JED;

“JMG” means JMG Exploration, Inc., a Nevada corporation;

“US Farmout Partner” means Petroflow Energy Ltd.;

"McDaniel" means McDaniel & Associates Consultants Ltd., independent petroleum engineering consultants;

"McDaniel Report" means the independent engineering evaluation of certain oil, NGL and natural gas interests of the Trust prepared by McDaniel dated February 17, 2009 and effective December 31, 2008;

"Non-Resident" means (a) a person who is not a resident of Canada for the purposes of the Tax Act and any applicable income tax convention; or (b) a partnership that is not a Canadian partnership for the purposes of the Tax Act;

"Old Enterra" means EEC prior to the Enterra Arrangement;

"Operating Subsidiaries" means collectively, the direct and indirect subsidiaries of the Trust that own and operate assets for the benefit of the Trust (with the material Operating Subsidiaries being EEC, EPP, EAC, and Enterra US Acqco);

"Reserve Reports" means, collectively, the McDaniel Report and Haas Report;

"Revolving and Operating Credit Facilities" means
(i) a revolving credit facility with a syndicate of lenders, and
(ii) ans operating facility with Bank of Nova Scotia as lender,
provided pursuant to the second amended and restated syndicated credit agreement dated June 25, 2008;

"RMAC Exchangeable Shares" means shares of RMAC that were exchangeable for Trust Units;

"RMEC" means Rocky Mountain Energy Corp., a corporation created by amalgamation under the laws of Alberta;

"RMG Exchangeable Shares" means exchangeable shares issued by Enterra US Acqco that were exchangeable for Trust Units;

"Second-Lien Credit Facility" means a second-lien non-revolving credit facility with a syndicate of lenders provided pursuant to a credit agreement dated June 25, 2008;

"Series Notes" means interest bearing subordinated promissory notes issued by certain Operating Subsidiaries and currently held by the Trust;

"Special Resolution" means a resolution passed as a special resolution at a meeting of holders of Trust Units and holders of Special Voting Rights (including an adjourned meeting) duly convened for the purpose and passed by the affirmative votes of the holders of not less than 66 2/3% of the Trust Units and Special Voting Rights represented at the meeting;

"Special Voting Right" means the special voting right of the Trust issued by the Trust to and deposited with the Trustee, which entitled the holders of the exchangeable shares to a number of votes at meetings of the Unitholders;

"Tax Act" means the Income Tax Act (Canada) and the Regulations thereunder, as amended from time to time;

"Technical Services Agreement" means the Technical Services Agreement between the Trust and JED dated effective January 1, 2004 and terminated on January 1, 2006;

"Trust" means Enterra Energy Trust, an unincorporated trust governed by the laws of Alberta, and where the context requires, includes the Trust and all of the Trust Subsidiaries as a consolidated entity;

"Trust Indenture" means the amended and restated trust indenture dated November 25, 2003 among Olympia Trust Company, as trustee, Luc Chartrand as settler, and EEC, as may be amended, supplemented, and restated from time to time;

"Trust Subsidiaries" means the Operating Subsidiaries, EECT, and any other subsidiaries of the Trust;

"Trust Units" mean units of the Trust;

"Trustee" means the trustee of the Trust, presently Olympia Trust Company;

"Unitholders" mean holders from time to time of the Trust Units;

"U.S. Person" means a U.S. person as defined in Rule 902(k) under Regulation S, including, but not limited to, any natural person resident in the United States; and

"U.S. Unitholder" means any Unitholder who is either in the United States or a U.S. Person.

Abbreviations, Conventions and Conversions

Abbreviations

AECO	Intra Alberta Nova Inventory Transfer Price (NIT net price)	Mboe	thousands of barrels of oil equivalent
API	American Petroleum Institute	mcf	thousand cubic feet of natural gas
°API"	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28°API or higher is generally referred to as light crude oil	mcf/d	thousand cubic feet of natural gas per day
ARTC	Alberta Royalty Tax Credit	Mmcf/d	million cubic feet of natural gas per day
bbl or bbls	barrels of oil	Mmcf	million cubic feet of natural gas
bbls per day or bbl/d	barrels of oil per day	mcf per day	thousands of cubic feet of natural gas per day
Bcf	Billion cubic feet of natural gas	mmbtu	millions of British Thermal Units
boe	barrels of oil equivalent (6 mcf equivalent to 1 bbl)	Mmbtu per day	millions of British Thermal Units per day
boe per day or boe/d	barrels of oil equivalent per day	Mwh	Megawatt hours
Cdn$	Canadian dollars	NGL or NGLs	natural gas liquids (ethane, propane, butane and condensate)
FD&A	Finding Development & Acquisition Costs	NI 51-101	National Instrument 51-101
FDC	Future Development Costs	NYMEX	New York Mercantile Exchange
GAAP	Canadian Generally Accepted Accounting Principles	Q1	first quarter of the year - January 1 to March 31
GJ	Gigajoule	Q2	second quarter of the year - April 1 to June 30
GJ/d	gigajoule per day	Q3	third quarter of the year - July 1 to September 30
GORR	Gross overriding royalty	Q4	fourth quarter of the year - October 1 to December 31
LNG	Liquefied Natural Gas	US$	United States dollars
m3	cubic metres	WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
mbbl	thousand barrels of oil		

Conventions

Unless otherwise indicated, all dollar amounts are in Canadian dollars and references herein to "$" or "dollars" are to Canadian dollars or "M$" are to a thousand Canadian dollars or "MM$" are to a million Canadian dollars.

The information set out in this 20-F is stated as at December 31, 2008 unless otherwise indicated. Capitalized terms used but not defined in the text are defined in the Glossary.

Conversions

The following table sets forth certain standard conversions from Standard Imperial Units to the International System of Units (or metric units):

To Convert from	To	Multiply by
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.4047
Hectares	Acres	2.471

PART 1

ITEM 1 - IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISORS

Not applicable.

ITEM 2 - OFFER STATISTICS AND EXPECTED TIMETABLE

Not applicable.

ITEM 3 - KEY INFORMATION

A. Selected Financial Data

The financial data set forth below as at December 31, 2008, 2007, 2006, 2005, and 2004 and for each of the years in the five year period ended December 31, 2008 have been derived from our audited consolidated financial statements and should be read in conjunction with those financial statements. The financial data has been prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP), the application of which, in the case of Enterra Energy Trust, conforms in all material respects for the periods presented with US GAAP, except as disclosed in footnotes to the financial statements.

The following table presents a summary of our consolidated statement of operations derived from our financial statements for the years ended December 31, 2008, 2007, 2006, 2005 and 2004. The monetary amounts in the table are in Canadian dollars ("C$"). All data presented below should be read in conjunction with ITEM 5 Operating and Financial Review and Prospects and ITEM 18 Financial Statements and accompanying notes included in this Form 20-F.

For the years ended December 31 (in thousands of Canadian dollars except for per unit amounts)	2008	2007	2006	2005	2004
Amounts in Accordance with Canadian GAAP					
FINANCIAL					
Revenue before mark-to-market adjustment (1)	255,268	223,828	233,592	157,743	108,293
Income (loss) before taxes	11,892	(177,986)	(121,850)	(16,292)	14,953
Per unit ($)	0.19	(2.98)	(2.76)	(0.55)	0.64
Net income (loss)	7,061	(142,036)	(64,239)	970	14,764
Per unit ($)	0.11	(2.38)	(1.46)	0.03	0.62
Per unit – diluted ($)	0.11	(2.38)	(1.46)	0.03	0.62
Total assets	587,018	599,790	795,366	611,543	200,301
Net assets	294,416	219,184	403,756	322,111	98,095
Unitholders' equity	294,416	219,184	402,024	289,707	98,095
SHARES AND UNITS OUTSTANDING					
Weighted average units outstanding (000s)	61,661	59,766	44,142	29,534	23,328
Units outstanding at period end (000s)	62,159	61,436	56,098	36,504	25,427

Amounts in Accordance with U.S. GAAP (2)

FINANCIAL					
Revenue before mark-to-market adjustment (1)	255,268	223,828	233,592	157,743	108,293
Income (loss) before taxes	(46,687)	(47,747)	76,787	(28,989)	7,536
Per unit ($)	(0.76)	(0.80)	1.71	(0.94)	0.32
Net income (loss)	(31,802)	(65,664)	(280,348)	(18,780)	10,338
Per unit ($)	(0.52)	(1.10)	(6.26)	(0.61)	0.44
Per unit – diluted ($)	(0.52)	(1.10)	(6.26)	(0.61)	0.44
Total assets	279,389	387,045	465,676	530,433	171,331
Net assets	2,995	22,247	115,026	262,821	80,037
Unitholders' equity, including mezzanine equity	2,995	22,247	115,026	262,821	80,037
SHARES AND UNITS OUTSTANDING					
Weighted average units outstanding (000s)	61,661	59,766	44,846	30,834	23,328
Units outstanding at period end (000s)	62,159	61,436	56,098	36,504	25,427

(1) Revenue before mark-to-market adjustment is a non-GAAP measure. Refer to the "Revenues" section in Item 5.A.
(2) See note 21 to the consolidated financial statements for an explanation of the significant differences between Canadian and U.S. GAAP.

Exchange Rate Information

We publish our consolidated financial statements in Canadian dollars. In this report, except where otherwise indicated, all dollar amounts are stated in Canadian dollars. References to "$" or "C$" are to Canadian dollars and references to "US$" are to U.S. dollars. The following table sets forth for each period indicated the period end exchange rates for conversion of U.S. dollars to Canadian dollars, the average exchange rates on the last day of each month during such period and the high and low exchange rates during such period. These rates are based on the noon buying rate in New York City, expressed in U.S. dollars, for wire transfers in Canadian dollars as certified for customs purposes by the Federal Reserve Bank of New York. The exchange rates are presented as U.S. dollars per Canadian dollar. On June 22, 2009, the noon buying rate was US$1.00 equals Cdn$1.1547 and the inverse noon buying rate was Cdn$1.00 equals US$0.8660.

U.S. Dollar per Canadian Dollar		
	High	Low
May 2009	0.9198	0.8423
April 2009	0.8375	0.7910
March 2009	0.8167	0.7692
February 2009	0.8202	0.7758
January 2009	0.8458	0.7849
December 2008	0.8358	0.7711

	Year Ended December 31 U.S. Dollar per Canadian Dollar				
	2008	2007	2006	2005	2004
Average	0.9381	0.9304	0.8818	0.8253	0.7683

B. Capitalization and Indebtedness

Not applicable.

C. Reasons for the Offer and Use of Proceeds

Not applicable.

D. Risk Factors

Volatility in oil and natural gas prices could have a material adverse effect on results of operations and financial condition, which, in turn, could affect the market price of the Trust Units or Debentures and the amount of distributions to Unitholders.

The Trust's business, results of operations, financial condition and future growth are substantially dependent on the prevailing prices for its production. Historically, the markets for oil and natural gas have been volatile and such markets are likely to continue to be volatile in the future. Prices for oil and natural gas are based on world supply and demand and are subject to large fluctuations in response to relatively minor changes in supply or demand, whether the result of uncertainty or a variety of additional factors beyond the Trust's control including, without limitation, actions taken by OPEC and its adherence to agreed production quotas, war, terrorism, government regulation, social and political conditions, economic conditions, prevailing weather patterns and the availability of alternative sources of energy. Any substantial decline in the price of oil or natural gas could have a material adverse effect on the Trust's revenues, operating income, cash flows and borrowing capacity and may require a reduction in the carrying value of the properties, planned level of spending for exploration, and development and level of reserves. No assurance can

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be given that prices for oil or natural gas will be sustained at levels that will enable the Trust to operate profitably or make distributions.

The Trust uses financial derivative instruments and other hedging mechanisms to try to limit a portion of the adverse effects resulting from decline in oil and natural gas prices. In addition, the commodity hedging activities could expose the Trust to losses. Such losses could occur under various circumstances, including where the other party to a hedge does not perform its obligations under the hedge agreement, the hedge is imperfect, or the hedging policies and procedures are not followed. Furthermore, it is unlikely that such hedging transactions will fully offset the risks of changes in commodity prices.

The Revolving and Operating Credit Facilities may not provide sufficient liquidity.

The Trust's Revolving and Operating Credit Facilities may not provide the Trust with sufficient funding for future operations, or Enterra may not be able to obtain additional financing on attractive economic terms, if at all. On June 25, 2008 Enterra entered into credit facilities with its banking syndicate that includes revolving and operating credit facilities which has a current borrowing capacity of $110.0 million. The revolving and operating credit facilities are secured with a first priority charge over the assets of Enterra. Borrowings under the revolving and operating credit facilities at March 31, 2009 were $80.0 million. The maturity date of the revolving and operating credit facilities is June 25, 2010 and should the lenders decide not to renew the facility, the debt must be repaid on June 25, 2011.

The Trust's obligations to its lenders may have a material adverse affect on the ability to pay distributions to Unitholders.

The payment of interest and principal, and other costs, expenses and disbursements to the lenders reduces the amounts available for potential distribution to Unitholders. Variations in interest rates and required principal repayments could result in significant changes to the amount of the funds from operations required to be applied to the debt before payment of any amounts to Unitholders. The agreement governing the Revolving and Operating Credit Facilities provides that if the Trust is in default of its terms, or if amounts outstanding exceed the amount of the borrowing base, the ability to make distributions to Unitholders may be restricted. On September 17, 2007 the Trust suspended its monthly distributions in order to redirect its cash flow to the repayment of its outstanding debt.

The Trust's assets are leveraged. Any material change in liquidity could impair its ability to make potential distributions to Unitholders and could adversely affect the market price of the Trust Units or Debentures.

The bank debt is secured by the Trust's assets. A decrease in the amount of production or the price received for it could make it difficult for the Trust to service the debt or may cause the lenders to determine that its assets are insufficient security for the debt. Repayment of all or a portion of outstanding amounts under the Revolving and Operating Credit Facilities may be demanded on relatively short notice. If this occurs, the Trust may need to obtain alternate financing. Any failure to obtain suitable replacement financing may have a material adverse effect on the Trust's business, or adversely affect the market price of the Trust Units or Debentures. On September 17, 2007 the Trust suspended its monthly distributions in order to redirect its cash flow to the repayment of its outstanding debt.

An inability to add additional reserves through development or acquisition could have a material adverse effect on the market price of the Trust Units or Debentures.

The Trust does not focus on the exploration for oil and natural gas reserves. Instead, the Trust adds to its oil and natural gas reserves primarily through development, exploitation and acquisitions. As a result, future oil and natural gas reserves are highly dependent on success in developing and exploiting existing properties and acquiring additional reserves. Accordingly, if external sources of capital, including the issuance of additional Trust Units or other

securities, become limited or unavailable on commercially reasonable terms, the Trust's ability to make the necessary capital investments to maintain or expand oil and natural gas reserves will be impaired. To the extent that the Trust is required to use funds from operations to finance capital expenditures or property acquisitions, the level of funds from operations available for distribution to Unitholders will be reduced. Additionally, the Trust cannot guarantee that it will be successful in developing or exploiting additional reserves or acquiring additional reserves on terms that meet its investment objectives. Without these reserve additions, the Trust's reserves will deplete and as a consequence, either production from, or the average reserve life of, the properties will decline. Either decline may result in a reduction in the value of the Trust Units and in a reduction in cash available for potential distributions to Unitholders.

A decline in the Trust's ability to market its oil and natural gas production could have a material adverse effect on production levels or on the price received for production, which, in turn, could have a material adverse effect on the market price of the Trust Units or Debentures.
The Trust's business depends in part upon the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities. Canadian federal and provincial, as well as United States federal and state, regulation of oil and gas production, processing and transportation, tax and energy policies, general economic conditions, and changes in supply and demand could adversely affect the Trust's ability to produce and market oil and natural gas. If market factors change and inhibit the marketing of the Trust's production, overall production or realized prices may decline, which could reduce potential distributions to Unitholders.

Fluctuations in foreign currency exchange rates could have a material adverse effect on the business.

The price that is received for a majority of the Trust's oil and natural gas is based on United States dollar denominated benchmarks, and therefore the price that is received in Canadian dollars is affected by the exchange rate between the two currencies. A material increase in the value of the Canadian dollar relative to the United States dollar may negatively impact net production revenue by decreasing the Canadian dollars received for a given United States dollar price. The Trust could be subject to unfavourable price changes to the extent that the Trust has engaged, or in the future engages, in risk management activities related to foreign exchange rates, through entry into forward foreign exchange contracts or otherwise.

Distributions, if any, may be reduced during periods in which capital expenditures are made or debt repaid using cash flow.

To the extent that the Trust uses cash flow to finance acquisitions, development costs and other significant expenditures, the portion of funds from operations that is available for distribution to Unitholders will be reduced. As a result, the timing and amount of capital expenditures may affect the amount of cash available to distribute to Unitholders. Distributions may be reduced, or even eliminated, at times when significant capital or other expenditures are made.

The Board of EEC, the administrator and principal operating subsidiary of the Trust, has the discretion to determine the extent to which funds from operations will be allocated to the payment of debt service charges as well as the repayment of outstanding debt, including under the Revolving and Operating Credit Facilities. As a consequence, the amount of funds EEC retains 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 so retained.

Actual reserves will vary from reserve estimates, and those variations could have a material adverse effect on the market price of the Trust Units or Debentures and distributions to Unitholders.

The reserve and recovery information contained in the Reserve Reports relating to the Trust's reserves are only estimates and the actual production and ultimate reserves from its properties may be greater or less than the estimates prepared by such firms.

The value of the Trust Units and Debentures depends upon, among other things, the reserves attributable to the Trust's properties. Estimating reserves is inherently uncertain. Ultimately, actual reserves attributable to the properties will vary from estimates, and those variations may be material. The reserve figures contained herein are only estimates. A number of factors are considered and a number of assumptions are made when estimating reserves. These factors and assumptions include, among others:

- historical production in the area compared with production rates from similar producing areas;
- future commodity prices, production and development costs, royalties and capital expenditures;

- initial production rates;
- production decline rates;
- ultimate recovery of reserves;
- success of future development activities;
- marketability of production;
- effects of government regulation; and
- other government levies that may be imposed over the producing life of reserves.

As a portion of the Trust's production is from geological formations with relatively limited long term production history, actual results are more likely to vary from estimates.

Reserve estimates are based on the relevant factors, assumptions and prices on the date the relevant evaluations were prepared. Many of these factors are subject to change and are beyond the Trust's control. If these factors, assumptions and prices prove to be inaccurate, actual results may vary materially from reserve estimates.

In addition, the level of production from the existing properties may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond the control of the Trust. A significant decline in production could result in materially lower revenues and cash flow and, therefore, could reduce the amount available for distributions to Unitholders.

As the Trust expands its operations beyond conventional oil and natural gas production in Western Canada, it may face new challenges and risks.

The Trust's operations and expertise were previously focused on the production of conventional oil and gas production and development in the Western Canadian Sedimentary Basin. In the first quarter of 2006, properties in Oklahoma were acquired. The Trust has gained significant experience operating in this jurisdiction but will still face operating and business challenges that it cannot foresee and therefore will need to rely on local management.
The Trust Indenture does not limit the Trusts activities to oil and gas production and development, and the Trust could acquire other energy related assets, such as oil and natural gas processing plants or pipelines. Expansion of activities into new areas presents challenges and risks that the Trust may not have faced in the past. If the Trust does not manage these challenges and risks successfully, results of operations and financial condition could be adversely affected.

Incorrect assessments of value at the time of acquisitions could have a material adverse effect on the market price of the Trust Units or Debentures and distributions to Unitholders.

The price that the Trust is willing to pay for reserve acquisitions is based largely on estimates of the reserves to be acquired. Actual reserves could vary materially from these estimates. Consequently, the reserves that are acquired may be less than expected, which could adversely impact cash flows and distributions to Unitholders. An initial assessment of an acquisition may be based on a report by engineers or firms of engineers that have different evaluation methods and approaches than those of the Trust's engineers, and these initial assessments may differ significantly from its subsequent assessments.

The Trust may undertake acquisitions that could limit its ability to manage and maintain the business, resulting in adverse accounting treatment or could be difficult to integrate into the business. Any of these events could result in a material change in the Trust's liquidity, impair its ability to make distributions to Unitholders and could adversely affect the market price of the Trust Units or Debentures.

A component of the future growth depends on the Trust's ability to identify, negotiate, and acquire additional entities and assets that complement or expand the existing operations. However the Trust may be unable to complete any acquisitions or any acquisitions that may be completed may not enhance the business. Any acquisitions could subject the Trust to a number of risks, including:

- diversion of management's attention;
- inability to retain the management, key personnel and other employees of the acquired business;
- inability to establish uniform standards, controls, procedures and policies;
- inability to retain the acquired company's customers;
- exposure to legal claims for activities of the acquired business prior to acquisition; and
- inability to integrate the acquired company and its employees into the organization effectively.

The exploration, development and operation of a portion of the Trust's properties is dependent on third-parties, and their failure to perform or harm to their business could adversely affect the revenues and ultimately the distributions to Unitholders.

The exploration and development of a portion of the Trust's properties may be undertaken by industry partners and a lack of success or an inability to perform by such partners would affect the future prospects, revenues and distributions.

The Trust still has limited experience operating properties in the United States and therefore is reliant on the local employees and on the U.S. Farmout partner for technical and operational support. It is the Trust's expectation that it will gain more insight into the technical and operational characteristics of each of these properties through these relationships. Any early termination or deterioration of the relationship with a partner, or any inability to rapidly understand the geology and production characteristics of the properties, could have a material adverse effect on the market price of the Trust Units or Debentures.

On properties where the Trust is not the operator, it is reliant on the operator for continuing production from the property, and to some extent, the marketing of that production. During 2008, approximately 5% of daily production was from properties operated by third-parties. To the extent a third-party operator fails to perform its functions efficiently or becomes insolvent, the Trust's revenue may be reduced. Third-party operators also make estimating future capital expenditures more difficult.

Further, the operating agreements which govern the properties not operated by the Trust typically require the operator to conduct operations in a "good and workman like" manner. These operating agreements generally provide, however, that the operator has no liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except for liabilities that may result from gross negligence or willful misconduct.

The exploration, development and exploitation of a portion of the Trust's properties is dependent on technological advancements becoming available on a timely basis. Any failure to obtain or delay in achieving the advancements could adversely affect the market price of the Trust Units or Debentures and distributions to Unitholders.

The exploration, development and exploitation of the Trust's properties and the ultimate amount of reserves recovered are dependant on being able to access technological advancements on a timely basis. If these technological advancements are not available it may not be possible to maximize the contribution to the market value of the Trust Units or Debentures. Delays in business operations could adversely affect the distributions to Unitholders.

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of the properties, and the delays of those operators in remitting payment to us, payments between any of these parties may also be delayed by:

- restrictions imposed by lenders;
- accounting delays;
- delays in the sale or delivery of products;
- delays in the connection of wells to a gathering system;
- blowouts or other accidents;
- adjustments for prior periods;
- recovery by the operator of expenses incurred in the operation of the properties; or
- the establishment by the operator of reserves for these expenses.

Any of these delays could reduce the amount of cash available for distribution to Unitholders in a given period and expose the Trust to additional third party credit risks.

Changes in market-based factors may adversely affect the trading price of the Trust Units or Debentures.

The market price of the Trust Units is primarily a function of anticipated distributions to Unitholders and the value of the Trust's properties. The market price of the Trust Units or Debentures is therefore sensitive to a variety of market-based factors, including, but not limited to, interest rates and the comparability of the Trust Units or Debentures to other similar securities. Any changes in these market-based factors may adversely affect the trading price of the Trust Units or Debentures.

The Trust's operations are entirely dependent on the Trust's management and the loss of key management and other personnel could negatively impact the business.

Unitholders are entirely dependent on the Trust's management with respect to the acquisition of oil and gas properties and assets, the development and acquisition of additional reserves, the management and administration of all matters

relating to the oil and natural gas properties and the administration of the Trust. The loss of the services of key individuals who currently comprise the management team could have a detrimental effect on us.

Management of the Trust may have conflicts of interest.

There are conflicts of interest to which several of the directors and officers are subject in connection with the Trust's operations. In particular, certain of the directors and officers are involved in managerial or directorial positions with other oil and gas companies whose operations, from time to time, are in direct competition with the Trust's operations. Additionally, certain of the directors and officers may become involved with entities which may, from time to time, provide financing to, or make equity investments in, the Trust's competitors. See "Conflicts of Interest and Interests of Management and Others in Material Transactions".

The Trust may be unable to successfully compete for resources with other organizations in the industry.

The Trust competes for capital, reserves, undeveloped lands, skilled personnel, access to drilling rigs, service rigs and other equipment, access to processing facilities, pipeline and refining capacity and in other respects with a substantial number of other organizations, many of which may have greater technical and financial resources than the Trust. Some of these organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market oil and other products on a worldwide basis. As a result of these complementary activities, some of the competitors may have greater and more diverse competitive resources to draw on than the Trust. In addition, to the extent Enterra's Trust Units receive a lower market valuation relative to competing entities, there will be a disadvantage in acquiring properties in competition with such entities. Given the highly competitive nature of the oil and natural gas industry, any competitive disadvantage could adversely affect the market price of the Trust Units or Debentures and distributions to Unitholders.

The industry in which the Trust operates exposes it to potential liabilities that may not be covered by insurance.

The Trust's operations are subject to all of the risks associated with the operation and development of oil and natural gas properties, including the drilling of oil and natural gas wells, and the production and transportation of oil and natural gas. These risks include encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, equipment failures and other accidents, sour gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, pollution, other environmental risks, fires and spills. A number of these risks could result in personal injury, loss of life, or environmental and other damage to the property or the property of others. The Trust cannot fully protect against all of these risks, nor are all of these risks insurable. The Trust may become liable for damages arising from these events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. Any costs incurred to repair these damages or pay these liabilities would reduce funds available for distribution to Unitholders.

The Trust may incur material costs and liabilities to comply with or as a result of health, safety and environmental laws and regulations.

The oil and natural gas industry is subject to extensive environmental regulation pursuant to local, state, provincial and federal legislation in Canada and the United States. A breach of that legislation may result in the imposition of administrative, civil or criminal penalties, damages, fines, the issuance of "clean up" orders or the issuance of injunctions limiting or prohibiting some or all of its operations. Strict liability may be incurred under these environmental regulations and legislation in connection with discharges or releases of petroleum hydrocarbons and wastes into the environment as a result of the operations. In addition, legislation regulating the oil and natural gas industry may be changed to impose higher standards and potentially more costly obligations. The 1997 Kyoto Protocol to the United Nations Framework Convention on Climate Change, known as the Kyoto Protocol, was ratified by the Canadian government in December 2002 and would require, among other things, significant reductions in greenhouse gases. In 2007, the Government of Canada released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan") also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers not only the oil and natural gas industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products. In 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the "Updated Action Plan") which provides some additional guidance with respect to the Government's plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050. Additionally in 2008, the Government of Canada and the Province of Alberta released the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force (the "Canada-Alberta ecoEnergy Plan"), which recommends among other things: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and

(iii) targeting research to lower the cost of technology. In 2007,

The impacts from the Kyoto Protocol, the Action Plan, the Updated Action Plan and the Canada-Alberta ecoEnergy Plan on the Trust are uncertain and may result in significant additional costs for the Trust's operations. Although the Trust records a provision in the financial statements relating to estimated future environmental and reclamation obligations, it cannot guarantee that it will be able to satisfy the actual future environmental and reclamation obligations.

Enterra is not fully insured against certain environmental risks, either because such insurance is not available or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (as opposed to sudden and catastrophic damages) is not available on economically reasonable terms. Accordingly, the Trust's properties may be subject to liability due to hazards that cannot be insured against, or that have not been insured against due to prohibitive premium costs or for other reasons. Any site reclamation or abandonment costs actually incurred in the ordinary course of business in a specific period will be funded out of funds

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from operations and therefore, will reduce the amount of funds available for distribution to Unitholders. Should the Trust be unable to fully fund the cost of remediating an environmental problem, it might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy.

Climate change impact

Enterra faces a variety of uncertainties related to climate change. The oil and gas industry is subject to extensive environmental regulation pursuant to local, provincial and federal legislation in Canada and federal and state laws and regulations in the United States. These range from potential impacts from emissions restrictions, carbon taxes and other government policy initiatives, to changes in weather patterns that may affect operations. Both the Alberta provincial government and the Canadian federal government have introduced planned legislative concepts that are intended, among other things, to drive industry towards CO2 emissions reduction and CO2 capture and sequestration in below ground geologic formations. In early 2008, the British Columbia provincial government announced its intention to introduce a carbon tax on fuels. Although Enterra is not a large emitter of greenhouse gases, these forms of legislation may have an impact on both revenues and cost structures at a future undetermined time.

Another potential climate change impact on the Trust may result from the direct consequences of weather events. These may range from extreme cold events, to early break up in winter-only areas and unusual storms.

Lower oil and gas prices increase the risk of impairment of the Trust's oil and gas property investments.

All costs related to the exploration for and the development of the Trust's oil and gas reserves are capitalized into one of two cost centers, Canada and the United States. Costs capitalized include land acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties and costs of drilling productive and non-productive wells and production equipment. General and administrative costs are capitalized if they are directly related to development or exploration projects. Proceeds from the disposal of oil and natural gas properties are applied as a reduction of cost without recognition of a gain or loss except where such disposals would result in a 20% change in the depletion rate.

Capitalized costs are depleted and depreciated using the unit-of-production method based on the estimated gross proven oil and natural gas reserves before royalties as determined by independent engineers. Units of natural gas are converted into barrels of equivalents on a relative energy content basis. The amounts recorded for depletion, depreciation and the asset retirement obligation are based on these estimates. The carrying value of the Trust's petroleum and natural gas properties, which may be depleted against revenues of future periods, is limited to the estimated fair value of these properties (the "ceiling test"). The ceiling test is conducted separately for each cost center. The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying value of the cost center. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of petroleum and natural gas properties exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate. The ceiling test calculation is based on estimates of reserves, production rates, oil and natural gas prices, future costs (including asset retirement costs) and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and may impact the consolidated financial statements of future periods. The risk that the Trust will be required to write down the carrying value of crude oil and natural gas properties increases when crude oil and natural gas prices are low or volatile.

While a write down does not directly affect funds from operations, the charge to earnings could be viewed unfavourably in the market or could limit the Trust's ability to borrow funds or comply with covenants contained in current or future credit agreements or other debt instruments.

Unforeseen title defects may result in a loss of entitlement to the production and reserves.

Although the Trust conducts title reviews in accordance with industry practice prior to any purchase of resource assets, such reviews do not guarantee that an unforeseen defect in the chain of title will not arise and defeat the title to the purchased assets. If such a defect were to occur, the Trust's entitlement to the production from such purchased assets could be jeopardized and, as a result, distributions to Unitholders may be reduced.

Aboriginal land claims.
The economic impact on the Trust of claims of aboriginal title is unknown. Aboriginal people have claimed aboriginal title and rights to a substantial portion of Western Canada. The Trust is unable to assess the effect, if any, that any such claim would have on the business and operations.

Electricity costs and water production may have an impact on operating costs.

The Trust's Oklahoma and Alberta properties consume significant quantities of electricity to drive motors and pumps for the production of hydrocarbons and the lifting and re-injection of formation water. The cost of electricity is a major component of lifting expense. While the Trust tries to purchases electrical power at competitive rates, it cannot guarantee that changes in market conditions and contract renewals will continue to allow operating costs to remain competitive and certain of the key fields profitable. Under these circumstances the Trust would attempt to seek alternatives including self-generation of its power requirements. However, it cannot guarantee that self-generation of power using its own product as fuel as an alternative to grid power will be either profitable or acceptable to landowners or regulators. A significant loss in profitability of key fields as a result of higher costs of electricity or lack of availability of electricity could affect future funds from operations and distributions.

Enterra's operations are subject to changes in governmental regulations and obtaining required regulatory approvals.

The oil and gas industry operates under federal, provincial, state and municipal legislation and regulation governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, income, the exportation of crude oil, natural gas and other products, as well as other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of field and mine sites (including restrictions on production), and possible expropriation or cancellation of contract rights.

Government regulations may be changed from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry could reduce demand for crude oil and natural gas, increase Enterra's costs and have a material adverse impact on Enterra.

Although not strictly governmental or regulatory in nature, the implementation of International Financial Reporting Standards to replace Canadian GAAP effective January 1, 2011 (and as a potential reporting alternative to U.S. GAAP or resulting in the elimination of the requirement to reconcile to U.S. GAAP) may have an adverse impact on the Trust's financial results as reporting in its financial statements, and may require Enterra to amend its Credit Facilities to address the changes in accounting principles.

Enterra's operations are subject to credit risks with its commodity purchasers with its commodity contract counterparties.

The Trust sells its production either directly to a refinery, an intermediary or a mid-stream purchaser. The Trust does not sell all of its production to any one purchaser and in any one month the Trust varies to whom it sells its production depending on several factors including availability of production, availability of capacity and contractual agreements. Settlements usually occur between 20 to 40 days after the end of the month. While the Trust reviews the credit ratings of the purchaser on a frequent basis the Trust is exposed to the risk of loss of proceeds of production if the purchaser fails to pay for the production due to financial failure of the purchaser.

Risks Related to the Trust Structure and the Ownership of Trust Units and Debentures

There would be material adverse tax consequences if the Trust lost its status as a mutual fund trust under Canadian tax laws.

Generally speaking, the Income Tax Act (Canada) (the "Tax Act") provides that a trust will permanently lose its "mutual fund trust" status (which is essential to the income trust structure) if it is established or maintained primarily for the benefit of non-residents of Canada (which is generally interpreted to mean that the majority of Unitholders must not be non-residents of Canada), unless at all times "all or substantially all" of the trust's property consisted of property other than certain taxable Canadian property (the "TCP Exception"). Based on the most recent information obtained through the Trust's transfer agent and financial intermediaries, in February 2009 an estimated 91% of the issued and outstanding Trust Units were held by non-residents of Canada (as defined in the Tax Act). The Trust is currently able to take advantage of the TCP Exception, and as a result, the Trust does not currently have a specific limit on the percentage of Trust Units that may be owned by non-residents. The Trust intends to continue to take the

necessary measures in order to ensure that it continues to qualify as a mutual fund trust under the Tax Act. However, the Trust may not be able to take steps necessary to ensure that it maintains its mutual fund trust status. Even if it is successful in taking such measures, these measures could be adverse to certain holders of Trust Units, particularly non-residents of Canada. The board of EEC could impose a specific limit on the number of Trust Units that could be beneficially owned by non-residents of Canada, similar to the non-resident ownership restrictions in place for other income funds in Canada, or could implement a dual-class unit structure which would effectively limit the aggregate number of Trust Units that could be owned by non-residents of Canada. Steps could be taken to ensure that no additional Trust Units are issued or transferred to non-residents, including limiting or suspending the trading of the Trust Units.

Should the status as a mutual fund trust be lost or successfully challenged by the Canada Revenue Agency, certain adverse consequences may arise for the Trust and its Unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

- The Trust would be subject to a special tax under Part XII.2 of the Tax Act of 36% of its "designated income" (which would not include interest on the Series Notes or the CT Notes). Payment of this tax may have adverse consequences for some Unitholders, particularly Unitholders that are non-residents of Canada and residents of Canada that are otherwise exempt from Canadian income tax;

- Trust Units and Debentures held by non-residents of Canada would become "taxable Canadian property". Non-resident holders would then be subject to Canadian tax reporting and payment requirements on any gains realized on a disposition of Trust Units or Debentures held by them;

- the Trust Units and Debentures may no longer constitute qualified investments under the Tax Act for registered retirement savings plans ("RRSPs"), registered retirement income funds ("RRIFs"), registered education savings plans ("RESPs"), or deferred profit sharing plans ("DPSPs") (collectively, "Exempt Plans"). If, at the end of any month, one of these Exempt Plans holds Trust Units or Debentures that are not a qualified investment, the plan must pay a tax equal to 1% of the fair market value of the Trust Units or Debentures at the time the Trust Units or Debentures were acquired by the Exempt Plan. An RRSP or RRIF holding Trust Units or Debentures that are not a qualified investment would be subject to taxation on income attributable to the Trust Units or Debentures, including the full amount of any capital gain from a disposition of the Trust Units or Debentures. If an RESP holds Trust Units or Debentures that are not a qualified investment, it may have its registration revoked by the Canada Revenue Agency; and

- the Trust would cease to be eligible for the capital gains refund mechanism available under the Tax Act.

Changes in tax and other legislation may adversely affect Unitholders.

Income tax laws, other legislation or government incentive programs relating to the oil and gas industry, such as the treatment of mutual fund trusts and resource allowance, may in the future be changed or interpreted in a manner that adversely affects the Trust and its Unitholders. Tax authorities having jurisdiction over the Trust and its Unitholders may disagree with the manner in which it calculates its income for tax purposes or could change their administrative practices to the Trust's detriment or the detriment of the Unitholders.

On March 23, 2004, the Canadian federal government announced proposed changes to the Tax Act, which would have effectively eliminated, over a period of time, the TCP Exception currently relied on by most oil and gas trusts to maintain their mutual fund trust status. However, as the proposed changes only affected mutual fund trusts that held contractual oil and gas royalties, the proposals would not have had a direct impact on us. In response to submissions from and discussions with stakeholders, the Canadian federal government suspended the implementation of those proposed amendments.

On June 12, 2007, federal legislation was enacted implementing a new tax (the "SIFT Tax") on certain publicly traded income trusts and limited partnerships, referred to as "Specified Investment Flow-Through" ("SIFT") entities. For SIFTs in existence on October 31, 2006 (including Enterra), the SIFT Tax will become effective in 2011. If certain rules related to "undue expansion" are not adhered to ("the normal growth guidelines"), the SIFT Tax will apply prior to 2011. Under the SIFT Tax, distributions of certain types of income will not be deductible for income tax purposes by SIFTs in 2011 and thereafter and any resultant trust level taxable income will be taxed at a rate that will be approximately equal to corporate income tax rates. The SIFT Tax rate is currently 29.5 percent in 2011 and 28.0 percent thereafter.

As noted above, the Trust could become subject to these changes before 2011 if it experiences growth, other than "normal growth", before that time. Under the December 15, 2006 guidelines, the Trust was considered to have experienced only "normal growth" if its issuances of new equity (which for this purpose includes Trust Units and debt

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that is convertible into Trust Units, but does not include non-convertible debt) did not exceed, for each of the intervening periods set forth below, a safe harbour measured by reference to the Trust's market capitalization as of the end of trading on October 31, 2006 (measured solely by the market value of the issued and outstanding Trust Units as of that date). The Trust's market capitalization as of October 31, 2006 was approximately $408 million. The intervening periods and their respective safe harbour amounts were as follows:

(a) November 1, 2006 to December 31, 2007 – 40% of the Trust's market capitalization as of October 31, 2006;

(b) January 1, 2008 to December 31, 2008 – 20% of the Trust's market capitalization as of October 31, 2006;

(c) January 1, 2009 to December 31, 2009 – 20% of the Trust's market capitalization as of October 31, 2006;

(d) January 1, 2010 to December 31, 2010 – 20% of the Trust's market capitalization as of October 31, 2006.

The December 15, 2006 guidelines provided that these annual safe harbour amounts are cumulative, and that replacing debt that was outstanding as of October 31, 2006 with new equity, whether through a Debenture conversion or otherwise, will not be considered growth for these purposes. In addition, an issuance of new equity will not be considered growth to the extent that the issuance is made in satisfaction of the exercise by another person of a right in place on October 31, 2006 to exchange an interest in a partnership, or a share of a corporation (such as exchangeable shares), for Trust Units.

On November 28, 2008, the Canadian Minister of Finance tabled a Notice of Ways and Means Motion in the House of Commons which contained proposed changes to the SIFT conversion provisions under the Income Tax Act. On December 4, 2008, the Minister released explanatory notes for the Motion which also contained revisions to the Department of Finance "normal growth" guidelines for grandfathered SIFTs. The revision to the “normal growth” guidelines has accelerated the Trust’s allowance to issue new equity without “undue expansion” and allows the Trust to issue its remaining safe harbour amount after December 4, 2008 without considering the previous timeline set out by the Department of Finance.

While the revised guidelines are such that it is unlikely they would affect the Trust's ability to raise the capital required to grow or maintain its existing operations in the ordinary course during the transition period, they could adversely affect the cost of raising capital and the Trust's ability to undertake more significant acquisitions.

There is no assurance that the Canadian federal government will not introduce other changes to the Tax Act directed at non-resident ownership which, given the Trust’s level of non-resident ownership, may result in the Trust losing its mutual fund trust status or could otherwise detrimentally affect it and the market price of the Trust Units.

The incurrence of tax by the Operating Subsidiaries could have a material adverse effect on the ability to pay distributions to Unitholders.

The Trust’s Operating Subsidiaries are subject to taxation in their respective taxation years on their respective taxable incomes for the year. The Operating Subsidiaries intend to deduct, in computing their income for tax purposes, the full amount available for deduction in each year associated with their income tax resource pools, undepreciated capital costs (“UCC”) and non-capital losses, if any. If there are not sufficient resource pools, UCC, non-capital losses carried forward, and interest to shelter the income of these Operating Subsidiaries, then cash taxes would be payable. In addition, there can be no assurance that taxation authorities will not seek to challenge the amount of resource pools, non-capital losses or interest expense relating to the Series Notes. If such a challenge were to succeed, it could materially adversely affect the amount of cash available for distribution to Unitholders and the market value of the Trust Units.

The cash available for distribution to Unitholders is ultimately sourced from these Operating Subsidiaries, some of which are in the United States and, as a result, subject to U.S. taxation. The Operating Subsidiaries that are subject to income taxation in the United States intend to deduct the full amount available in respect of depletion, depreciation, interest or other allowances under applicable law to reduce taxable income of such Operating Subsidiaries. There can be no assurances, however, that the taxation authorities of the United States will not challenge the amount of such deductions. If such a challenge were to succeed it could materially adversely affect the amount of cash available for distribution to Unitholders. Changes to the income tax law in the United States, changes to tax regulations in the United States, or changes in the interpretation or application of such law or regulations may result in increased taxation of funds generated in the United States and may adversely affect distributions to Unitholders and the market value of the Trust Units.

Interest and dividends that are received from the Operating Subsidiaries in the United States will be subject to United States withholding taxes the amount of which will be determined under applicable law, income tax treaties and regulations. In this regard, the United States Treasury Department has announced its intention to renegotiate one of the income tax treaties upon which the Trust relies for a reduction in withholding taxes on distributions from the Operating Subsidiaries in the United States. Changes in the applicable law, income tax treaties or regulations or in the application or interpretation thereof may increase such withholding taxes and may adversely affect distributions to Unitholders.

Unitholders may be required to pay taxes even if they do not receive any cash distributions.

Interest on the Series Notes and the CT Notes accrues at the Trust level for income tax purposes whether or not actually paid. The Trust Indenture provides that an amount equal to the taxable income of the Trust will be payable each year to Unitholders in order to reduce the Trust's taxable income to zero. The Trust Indenture provides that where, in a particular year, the Trust does not have sufficient available cash to distribute such an amount to the Unitholders, additional Trust Units will be distributed to Unitholders in lieu of cash payments. Unitholders will generally be required to include an amount equal to the fair market value of those Trust Units in their taxable income, notwithstanding that they do not directly receive a cash payment.

United States Unitholders may be limited in their ability to use the Canadian withholding tax as a credit against United States federal income tax and in their ability to claim the effect of certain other favourable United States income tax provisions.

It is expected that the Trust will be classified for United States federal income tax purposes as a partnership and not as a corporation. As a result, a citizen of the United States and each other person who is subject to United States federal income tax on a net income basis with respect to the Trust Units (each such person is referred to herein as a U.S. Holder) will generally include its share of the income, gain, loss, deduction and credit of the Trust on its United States federal income tax return in determining its liability for the United States federal income tax.

The Canadian income taxes that are withheld (currently at a 15 percent rate) from a distribution to a U.S. Holder on a Trust Unit may be deducted or, subject to limitations, used as a credit for United States federal income tax purposes. The limitation under United States law on foreign taxes that may be used as credits is calculated separately with respect to specific classes of income or "baskets". That is, the use of foreign taxes that are paid with respect to income in any such basket as a credit is limited to a percentage of the foreign source income in that basket. Special rules apply in determining the foreign tax credit limitation with respect to dividends that are subject to the 15 percent rate (discussed below). Under rules of general application, a portion of a U.S. Holder's interest expense and other expenses can be allocated to, and thereby reduce, the foreign source income in any basket. Any gain that is recognized by a U.S. Holder on the sale of a Trust Unit that is recognized because a distribution thereon is in excess of basis in that security will generally constitute income from sources within the United States for U.S. foreign tax credit purposes and will therefore not increase the ability to use foreign taxes as credits.

For a U.S. Holder who is a non-corporate Unitholder, its share of the Trust's dividend income from its Canadian subsidiaries received before January 1, 2011 should be subject to United States federal income tax at a maximum rate of 15 percent provided that, among other things, (a) that the payor of the dividend is not classified as a PFIC during the taxable year in which such distribution is paid or the preceding taxable year, (b) that the U.S. Holder has satisfied certain holding period requirements, and (c) that the U.S. Holder has not made an election to treat the dividend as "investment income" for purposes of the investment interest deduction rules. In addition, the rate reduction will not apply to dividends if the recipient of a dividend is obligated to make related payments with respect to positions in substantially similar or related property. This disallowance applies even if the minimum holding period has been met. If the rate reduction is not applicable, the dividends would be subject to United States federal income taxation at

ordinary income tax rates.

Each such U.S. Holder should discuss the effect of the limitations on the use of such Canadian taxes as a credit (including the effect of any ability to obtain a refund of such Canadian withholding tax in certain circumstances) and the limitations on obtaining the favourable United States federal rate reduction with its own advisers.

United States Unitholders who are generally tax exempt under United States law may recognize unrelated business taxable income (which is subject to United States federal income tax) in respect of their Trust Units.

Individual retirement accounts, other employee benefit plans and certain organizations that are generally exempt from United States federal income tax are subject to United States federal income tax on unrelated business taxable income, such as certain income from debt financed property, to the extent that such unrelated business taxable income for a taxable year is in excess of $1,000. The Trust has in the past and may in the future incur debt, the proceeds of which are invested in stock of EEC or another corporation. In that event, the dividends that the Trust

receives from such corporation (which flow through to the holders of Trust Units while the Trust is a treated as a partnership for United States federal income tax purposes) will be unrelated business taxable income.

Such an individual retirement account or other tax exempt organization will generally also be subject to Canadian withholding tax on distributions that the Trust makes and will as a general matter be able to use all or a portion of that Canadian withholding tax as a credit against the United States federal income tax for which it is liable on any unrelated business taxable income in accordance with applicable law and with due regard to the applicable restrictions thereon. Such Canadian income tax will not as a general matter reduce or otherwise affect the Untied States federal income taxation of distributions that an individual retirement account or other employee benefit plans makes to its beneficiary or beneficiaries.

United States Unitholders may be subject to passive foreign investment company rules.

Although the Trust does not expect that any of the Trust's subsidiaries that are corporations for United States federal income tax purposes (or the Trust if it were to be a corporation for such purposes) is or has been a passive foreign investment company, or PFIC, there is no assurance in that regard.

A foreign corporation is, as a general matter, a PFIC if either (a) 75 percent or more of its gross income in a taxable year, including the pro rata share of the gross income of certain partially owned (whether directly or indirectly) corporations, is passive income (as defined in the pertinent provisions of the Code) or (b) 50 percent or more of its assets (including the pro rata share of the assets of any such partially owned subsidiary) are held for the production of, or to produce, passive income.

If the Trust or any of its subsidiaries were a PFIC, then a U.S. Holder who did not make an election to treat such corporation as a qualified electing fund (there is no assurance that it will be able to make such an election) would pay United States federal income tax on any "excess distributions" in respect of the PFIC stock (even if such U.S. Holder did not own stock in the PFIC directly) is allocated rateably over the U.S. Holder's holding period. The amounts allocated to the taxable year of the excess distribution and to any year before the relevant stock interest became a PFIC would be taxed as ordinary income. The amount allocated to each taxable year would be subject to United States federal income taxation at the highest rate in effect for individuals or corporations in such taxable year, as appropriate, and an interest charge would be imposed on the amount allocated to that taxable year. Distributions made in respect of the relevant PFIC stock interest during a taxable year (including any gain realized on the sale or other disposition of the PFIC stock, even if the cash proceeds thereof were not received) will be an excess distribution to the extent they exceed 125 percent of the average of the annual distributions in respect of said stock interest received by the U.S. Holder during the preceding three taxable years or the U.S. Holder's holding period, whichever is shorter. Moreover, any non-corporate Unitholder who is a U.S. Holder would not be entitled to the 15 percent maximum rate of Untied States federal income tax on any dividend that is received in respect of the stock in any such PFIC.

U.S. Holders are urged to consult their own tax advisors regarding the United States federal income tax consequences of classification as a PFIC of any corporation in which the Trust owns an interest (or the Trust) and of the consequences of such classification.

United States and other non-resident Unitholders may be subject to additional taxation.

The Tax Act and the tax treaties between Canada and other countries may impose additional withholding or other taxes on the cash distributions or other property paid by the Trust to Unitholders who are not residents of Canada, and these taxes may change from time to time. For instance, since January 1, 2005, a 15 percent withholding tax is applied to return of capital portion of distributions made to non-resident Unitholders.

The ability of United States and other non-resident investors to enforce civil remedies may be limited.

Enterra is a trust organized under the laws of Alberta, Canada, and EEC's principal offices are in Canada. Most of the Trust's directors and officers are residents of Canada and most of the experts who provide services to the Trust (such as its auditors and some of its independent reserve engineers) are residents of Canada, and all or a substantial portion of their assets and the assets of the Trust are located within Canada. As a result, it may be difficult for investors in the United States or other non-Canadian jurisdictions (a "Foreign Jurisdiction") to effect service of process within such Foreign Jurisdiction upon such directors, officers and representatives of experts who are not residents of the Foreign Jurisdiction or to enforce against them judgement of courts of the applicable Foreign Jurisdiction based upon civil liability under the securities laws of such Foreign Jurisdiction, including United States federal securities laws or the securities laws of any state within the United States. In particular, there is doubt as to the enforceability in Canada against EEC or any of its directors, officers or representatives of experts who are not residents of the Untied States, in original actions or in actions for enforcement of judgments of United States courts of

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liabilities based solely upon the Untied States federal securities laws or the securities laws of any state within the United States.

Rights as a Unitholder differ from those associated with other types of investments.

The Trust Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in the Trust or the Trust Subsidiaries. The Trust Units represent an equal fractional beneficial interest in the Trust and, as such, the ownership of the Trust Units does not provide Unitholders with the statutory rights normally associated with ownership of shares of a corporation, including, for example, the right to bring "oppression" or "derivative" actions. The unavailability of these statutory rights may also reduce the ability of Unitholders to seek legal remedies against other parties on the Trust's behalf.

The Trust Units are also unlike conventional debt instruments in that there is no principal amount owing to Unitholders. The Trust Units will have minimal value when reserves from its properties can no longer be economically produced or marketed. Unitholders will only be able to obtain a return of the capital they invested during the period when reserves may be economically recovered and sold. Accordingly, cash distributions do not represent a "yield" in the traditional sense as they represent both return of capital and return on investment and the distributions received over the life of the investment may not meet or exceed the initial capital investment.

The limited liability of Unitholders of the Trust is uncertain.

Notwithstanding the fact that Alberta (the Trust's governing jurisdiction) has adopted legislation purporting to limit Unitholder liability, because of uncertainties in the law relating to investment trusts, there is a risk that a Unitholder could be held liable for obligations of the Trust in respect of contracts or undertakings which the Trust enters into and for certain liabilities arising otherwise than out of contracts including claims in tort, claims for taxes and possibly certain other statutory liabilities. Although every written contract or commitment of the Trust must contain an express disavowal of liability of the Unitholders and a limitation of liability to Trust property, such protective provisions may not operate to avoid Unitholder liability. Notwithstanding attempts to limit Unitholder liability, Unitholders may not be protected from liabilities of the Trust to the same extent that a shareholder is protected from the liabilities of a corporation. Further, although the Trust has agreed to indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by the Unitholder resulting from or arising out of that Unitholder not having limited liability, the Trust cannot guarantee that any assets would be available in these circumstances to reimburse Unitholders for any such liability. There can be no assurance that the Alberta legislation purporting to limit Unitholder liability eliminates the risk that a Unitholder could be held liable for obligations of the Trust, and the legislation does not affect liability with respect to any act, default, obligation or liability that arose prior to July 1, 2004.

The cash redemption rights of Unitholders are limited.

Unitholders have a right to require the Trust to repurchase their Trust Units, which is referred to as a redemption right. It is anticipated that the redemption right will not be the primary mechanism for Unitholders to liquidate their investment. The Trust's obligation to pay cash in connection with redemption is subject to limitations. Any securities, which may be distributed to Unitholders in connection with redemption, may not be listed on any stock exchange and a market may not develop for such securities. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the redemption right.

There may be future dilution.

One of the objectives is to continually add to the Trust's reserves through acquisitions and through development. Since at present the Trust does not reinvest the majority of its cash flow, its success is, in part, dependent on its ability to raise capital from time to time by selling additional Trust Units. Unitholders will suffer dilution as a result of these offerings if, for example, the cash flow, production or reserves from the acquired assets do not reflect the additional number of Trust Units issued to acquire those assets. Unitholders may also suffer dilution in connection with future issuances of Trust Units to effect acquisitions.

Unitholders will also suffer dilution as a result of the conversion of any of the Trust's Debentures, or if the Trust redeems outstanding Debentures for Trust Units or satisfies the obligation to pay interest on the Debentures by issuing additional Trust Units. See "Description of Debentures".

Prior distributions are not reflective of future distributions.

Historical distributions are not reflective of future distributions. Future distributions will be subject to review by, and are in the discretion of, the board of EEC. On September 17, 2007 the Trust suspended its monthly distributions in order to redirect its cash flow to the repayment of its outstanding debt.

The actual amounts distributed, if any, will be based on the circumstances as they exist at the time and will be subject to a number of factors, many of which are beyond the Trust's control including, without limitation, the outlook for commodity prices and other macro-economic factors, the availability and cost of equity and debt financing, the size and nature of the prospects and opportunities available to us, and its financial position and commitments.

There may not always be an active trading market for the Trust Units and Debentures.

While there is currently an active trading market for the Trust Units in the United States and Canada and for the Debentures in Canada, there are no assurances that an active trading market will be sustained.

ITEM 4 – INFORMATION ON THE COMPANY

A. History and Development of the Company

Enterra Energy Trust

Enterra Energy Trust is an oil and gas trust established under the laws of the Province of Alberta pursuant to the Trust Indenture dated as of October 24, 2003, between Enterra Energy Corp. and Olympia Trust Company (the "Trust Indenture"). The Trust's assets consist of the securities of the Trust Subsidiaries and indirect interests in crude oil and natural gas properties through the Operating Subsidiaries. The Trust's head office is located at Suite 2700, 500 - 4th Avenue S.W., Calgary, Alberta, Canada T2P 2V6, Tel: (403) 263-0262. The Trust's registered office is located at 4300 Bankers Hall West, 888 – 3rd Street S.W., Calgary, Alberta, Canada T2P 5C5. Our agent for service of process in the United States is CT Corporation, 2610, 520 Pike Street, Seattle, Washington 98101.

As a result of the completion of a plan of arrangement involving the Trust, Enterra Energy Corp. ("Old Enterra"), Enterra Acquisition Corp. and Enterra Energy Commercial Trust ("EEC Trust" or "Commercial Trust") (the "Arrangement") on November 25, 2003, former holders of common shares of Old Enterra received two trust units or two Exchangeable Shares of Enterra Acquisition Corp., in accordance with the elections made by such holders, and Old Enterra became a subsidiary of the Trust. Old Enterra was subsequently amalgamated with Enterra Acquisition Corp. to form Enterra Energy Corp. ("New Enterra").

The principal undertaking of the Trust is to issue trust units and to acquire and hold debt instruments, royalties and other interests. The direct and indirect wholly owned subsidiaries of the Trust carry on the business of acquiring and holding interests in petroleum and natural gas properties and assets related thereto.

Olympia Trust Company has been appointed as trustee under the Trust Indenture. The beneficiaries of the Trust are holders of the outstanding trust units. The principal and head office of Olympia Trust Company is located at 2300, 125 – 9th Avenue S.E., Calgary, Alberta T2G 0P6.

History and Significant Acquisitions

2006 Acquisition of Oklahoma Assets

During the first six months of 2006, Enterra acquired oil and natural gas producing assets located in Oklahoma ("Oklahoma Assets"). The acquisition was completed through four closings. The first closing occurred on January 18, 2006 and represented approximately 1,300 BOE/d of production capacity. The second closing occurred on March 21, 2006 and represented approximately 3,700 BOE/d of production capacity. The final two closings occurred on April 4, 2006 and April 18, 2006 and represented approximately 1,300 BOE/d of production capacity. The assets consisted of approximately 80% natural gas and 20% light oil production and included approximately 53,000 net acres of land of which over 25,000 net acres were undeveloped. The purchase price of US$307.6 million was paid for through the issuance of 5,685,028 Trust Units valued at $116.5 million, $181.0 million of cash and closing costs of $10.0 million.

The current and anticipated production from the Oklahoma Assets is primarily from the Hunton Group carbonate formations and is derived through a de-pressuring of the formation via water production followed by hydrocarbon production. The Hunton Group is exploited at depths of approximately 1,500 metres using long, multi-leg horizontal

wells. Enterra operates all of its related production, gathering and water disposal facilities. On June 27, 2006, a farm-out agreement was entered into with a U.S. Farmout Partner to exploit the undeveloped Hunton Group prospects.

2006 Property Swap with JED Oil Inc.

On September 28, 2006, Enterra closed a property swap agreement with JED Oil Inc. whereby Enterra swapped certain of its interests in properties in the Ferrier area of Alberta for interests of JED in common with Enterra's in East Central Alberta, the Desan area of Northeast British Columbia and the Ricinus area of Alberta. The swap was based on independent third party engineering evaluations and was effective July 1, 2006. The transaction also resulted in the termination of an Agreement of Business Principles between the Trust and JED whereby the Trust had a right of first refusal on properties that JED owned and JED had the ability to farm-in on the Trust's undeveloped lands. Concurrent with the swap, the Trust settled all amounts owing to JED.

2007 Acquisition of Trigger Resources Ltd.

On April 30, 2007, Enterra acquired all of the issued and outstanding shares of Trigger Resources Ltd.("Trigger Resources"). Trigger Resources shareholders received cash consideration of $63.3 million which was funded by the issuance of $40.0 million of 8.25% convertible Debentures that mature on June 30, 2012 and $29.2 million of Trust Units (4,945,000 trust units). Trigger Resources' oil and natural gas properties are located in west central and southwest Saskatchewan and, at the time of acquisition, added approximately 2,400 BOE/d (58% oil, 42% gas) to Enterra's production portfolio. The properties generally have 100% working interest with year round access and relatively low operating costs.

2007 Disposition of Non-core Assets

Enterra regularly evaluates asset acquisition and divestiture candidates. This practice, in conjunction with Enterra's debt reduction strategy, led the Trust in 2007 to review and identify assets deemed to be "non-core" to its ongoing operations. These assets were then publicly marketed in the fall of 2007. Enterra received numerous proposals for the assets marketed in addition to several unsolicited offers for non-core assets that had not been actively marketed. During 2007 certain Princess non-operated, Willesden Green and Little Bow properties were sold.

2008 Disposition of Non-core Assets

In 2008 Enterra's primary goals have been debt reduction, increased operational focus and efficiency and replacement of produced reserves. During 2008 the Trust closed the sale of non-core assets for proceeds of $39.6 million. Substantially all net proceeds were applied to debt reduction of the Trust.

Equity Offerings
2006 Financings

On March 3, 2006 Enterra filed a prospectus supplement for the issuance of up to 1,500,000 Trust Units at US$17.25 per unit. 275,000 Trust Units were issued under this prospectus supplement for proceeds of $5.4 million. Funds received from this financing were used for capital expenditures and for general corporate purposes.

On November 10, 2006 Enterra filed a short form prospectus for the issuance of 4,979,500 Trust Units at $8.10 per unit for proceeds of $40.3 million. Funds received from this financing were used to partially repay Enterra's then-existing bridge credit facilities.

On November 10, 2006 Enterra filed a short form prospectus for the issuance of $138,000,000 of 8% Debentures convertible into Trust Units at $9.25 per unit. The funds received from this financing were used to partially repay Enterra's then-existing bridge credit facilities. As at December 31, 2006 $57,669,000 of the convertible Debentures had been converted into 6,234,483 Trust Units.

2007 Financings

On April 11, 2007 Enterra filed a preliminary short form prospectus for the issuance of up to 4,945,000 Trust Units, inclusive of the underwriter's over-allotment option of 645,000 Trust Units, at a price of $5.90 per Trust Unit for gross proceeds of $29.2 million and $40.0 million of 8.25% Debentures convertible into Trust Units at a price of $6.80 per Trust Unit. The net proceeds of this issuance were used to finance the acquisition of Trigger Resources.

B. Business Overview

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1. Nature of the Business

Enterra is an exploration and production oil and gas trust based in Calgary, Alberta, Canada with its United States operations office located in Oklahoma City, Oklahoma. Enterra's trust units are listed on the New York Stock Exchange (ENT) and Enterra's trust units and convertible debentures are listed on the Toronto Stock Exchange (ENT.UN, ENT.DB and ENT.DB.A).

Competitive Strengths

The Trust has a number of competitive strengths which will enhance the execution of its business strategy. Its competitive strengths include:

Diversified Production Base

The Trust's assets are principally located in four areas: north east British Columbia, Alberta, Saskatchewan and Oklahoma. While each area has different geological, production and infrastructure characteristics, in aggregate they have historically provided a stable source of production.

Large Portfolio of Development Projects

The Trust's properties contain a number of potential development projects, which supports the strategy of reserving a portion of funds from operations to invest in organic growth opportunities. Currently, there are a significant number of drilling opportunities on approximately 150,666 net acres of undeveloped land.

U.S. Platform Distinguishes the Trust from Other Canadian Oil & Gas Trusts

Based on average production during 2008, approximately 45% of the Trust's production is in the United States. The Trust's presence in both countries, in terms of people and assets, provides it with a broader range of opportunity, improves its perspective when evaluating projects or acquisitions, and reduces the dependence on the highly competitive Canadian market.

Commodity Price Hedges

As part of the active risk management program up to 50% of the projected gross production is hedged for up to 24 months in advance, the Trust has entered into a series of collars to reduce the impact of short-term fluctuations in crude oil and natural gas prices. The terms of the transactions are detailed in the notes to the 2008 consolidated annual financial statements and in Item 5 A. Operating Results - Commodity Contracts.

Experienced Management Team

In late 2007, the Trust had made several changes to its management team which has resulted in the formation of a strong, experienced and committed management team that has demonstrated its ability to identify and successfully execute the Trust's business plans.

Personnel

At December 31, 2008, the Trust employed or contracted 54 office personnel and 36 field operations personnel in its Canadian operations and 20 office personnel and 33 field operations personnel in its U.S. operations for a total of 143

employees.

Business Strategy During 2008

The Trust's portfolio of oil and gas properties is geographically diversified with producing properties located principally in Alberta, British Columbia, Saskatchewan and Oklahoma. Average production during 2008 was 10,283 boe per day comprised of approximately 63% natural gas and 37% crude oil and natural gas liquids ("NGL"). For 2009, production is expected to be approximately 47% oil and NGL and 53% natural gas due to new marketing contracts in Oklahoma that recognize more volume for the natural gas liquids in the production stream. Enterra has compiled a multi-year drilling inventory for its properties.

Enterra had some significant accomplishments during the year primarily in the areas of focus which were debt reduction and reserve replacement. Additional highlights were:

- Total bank debt was decreased to $95.5 million, a reduction of $76.5 million during the year, and has been further reduced by approximately $15.5 million since the end of 2008.
- Net debt was reduced to $52.4 million from $168.2 million at the end of 2007. This is a decrease of 69 percent.
- Funds from operations grew by 48 percent year over year to $107.3 million compared to $72.7 million for 2007.
- Production averaged 10,283 boe per day a decrease of 17 percent, despite the disposition of certain producing properties during the first half of the year.
- Finding and development costs declined by 25 percent to $8.24/boe (P+P excluding FDC) from $10.93/boe.
- Reserves produced during 2008 were replaced on a proved plus probable basis, through an effective capital spending program and the negotiation of new marketing agreements in Oklahoma.
- Participated in 42 wells (17.4 net) attaining a 97% success rate.

2. Markets and Revenues

Producers of oil negotiate sales contracts directly with oil purchasers, generally obtaining in a market price for oil. The price depends, in part, on oil type and quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance and other contractual terms, as well as on the world price of oil. The price of natural gas sold in intraprovincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The price depends, in part, on natural gas quality, prices of competing natural gas and other fuels, distance to market, access to downstream transportation, length of contract term, seasonal factors, weather conditions, the value of refined products, the supply/demand balance and other contractual terms

Our revenue is obtained from the sale of oil and natural gas. The revenues for the last three years were:

	For the year ended December 31,		
($000s)	2008	2007	2006
Canada	151,675	138,844	152,254
United States	103,593	84,984	81,338
Revenue	255,268	223,828	233,592

3. Seasonality

The business is somewhat seasonal in nature because a significant portion of the demand for natural gas is during the winter heating season in North America which can result in seasonal commodity price volatility. We produce the oil and gas and then sell the oil and gas to marketing companies and integrated oil and gas companies that then arrange for the oil and gas to be further refined and processed and they sell the refined products to the ultimate end users.

4. Volatility of Prices

The Trust's business, results of operations, financial condition and future growth are substantially dependent on the prevailing prices for its production. Historically, the markets for oil and natural gas have been volatile and such markets are likely to continue to be volatile in the future. Prices for oil and natural gas are based on world supply and demand and are subject to large fluctuations in response to relatively minor changes in supply or demand, whether the result of uncertainty or a variety of additional factors beyond the Trust's control including, without limitation, actions taken by OPEC and its adherence to agreed production quotas, war, terrorism, government regulation, social and political conditions, economic conditions, prevailing weather patterns and the availability of alternative sources of energy. Any substantial decline in the price of oil or natural gas could have a material adverse effect on the Trust's revenues, operating income, cash flows and borrowing capacity and may require a reduction in the carrying value of the properties, planned level of spending for exploration, and development and level of reserves. No assurance can be given that prices for oil or natural gas will be sustained at levels that will enable the Trust to operate profitably or

make distributions.

5. Marketing Channels

The Trust uses financial derivative instruments and other hedging mechanisms to try to limit a portion of the adverse effects resulting from decline in oil and natural gas prices. In addition, the commodity hedging activities could expose the Trust to losses. Such losses could occur under various circumstances, including where the other party to a hedge does not perform its obligations under the hedge agreement, the hedge is imperfect, or the hedging policies and procedures are not followed. Furthermore, it is unlikely that such hedging transactions will fully offset the risks of changes in commodity prices.

6. Patents and Licenses

Enterra is not dependent on any patents or licenses in order to conduct business.

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7. Competition

The petroleum industry is highly competitive. We compete with numerous other participants in the acquisition of oil and gas leases and properties, and the recruitment of employees. Competitors include oil companies and other income trusts, many of whom have greater financial resources, staff and facilities than we have. Our ability to increase reserves in the future will depend not only on our ability to develop existing properties, but also on our ability to select and acquire suitable additional producing properties or prospects for drilling. We also compete with numerous other companies in the marketing of oil. Competitive factors in the distribution and marketing of oil include price and methods and reliability of delivery.

8. Government Regulation in Canada and the United States

The oil and natural gas industry is subject to extensive controls and regulations governing its operations, including land tenure, exploration, development, production, refining, transportation and marketing, imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta, British Columbia, Saskatchewan, United States and Oklahoma all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect our operations in a manner materially different from how they would affect other oil and gas companies of similar size operating in Western Canada and Oklahoma. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted.

Enterra's U.S. oil and natural gas operations are regulated by administrative agencies under statutory provisions of the state of Oklahoma where such operations are conducted and by certain agencies of the federal government for operations on federal leases. These statutory provisions regulate matters such as the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements in order to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. Enterra's U.S. operations are also subject to various conservation laws and regulations which regulate matters such as the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Pricing and Marketing - Oil

Crude oil exported from Canada is subject to regulation by the National Energy Board (the "NEB") and the Government of Canada. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of light crude oil, and not exceeding two years in the case of heavy crude oil, provided that an order approving any such export has been obtained from the NEB. Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB and the issue of such a license requires the approval of the Governor in Council.

Pricing and Marketing – Natural Gas

Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 cubic metres per day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export license from the NEB and the issue of such a license requires the approval of the Governor in Council.

The governments in the Canadian provinces where Enterra operates also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere, based on such factors as reserve availability, transportation arrangements and market considerations.

Royalties and Incentives
Canada:
In addition to federal regulation, each province has legislation and regulations, which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from

lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry.

United States:
The royalties incurred by Enterra's Oklahoma operations are in the form of freehold royalties which are charged by the individual mineral owner and production taxes which are charge by the state of Oklahoma. The freehold royalty rate is determined by negotiations between the mineral owner and the lessee at the beginning of the lease. The production tax is charged by the Oklahoma Tax Commission and is based on either prices received or production volumes and is determined when the well is drilled. The current production tax rate is approximately seven percent. There is currently a six percent production tax rebate for the first 24 months of production on horizontal wells.

In late October 2007, the Alberta provincial government announced a new oil and gas royalty regime that took effect January 1, 2009. The Trust has assessed the impact of the new royalty regime and has determined that it will have a modest negative effect on its current portfolio of production and reserves in Alberta. Enterra now incorporates the new royalty scheme into its Alberta-based economic analysis prior to pursuing opportunities in the province. During 2008, approximately 31% of the Trust's production came from Alberta.

Tax Legislation
Income tax laws, other legislation or government incentive programs relating to the oil and gas industry, such as the treatment of mutual fund trusts and resource allowance, may in the future be changed or interpreted in a manner that adversely affects the Trust and its Unitholders. Tax authorities having jurisdiction over the Trust and its Unitholders may disagree with the manner in which it calculates its income for tax purposes or could change their administrative practices to the Trust's detriment or the detriment of the Unitholders.

On March 23, 2004, the Canadian federal government announced proposed changes to the Tax Act, which would have effectively eliminated, over a period of time, the TCP Exception currently relied on by most oil and gas trusts to maintain their mutual fund trust status. However, as the proposed changes only affected mutual fund trusts that held contractual oil and gas royalties, the proposals would not have had a direct impact on Enterra. In response to submissions from and discussions with stakeholders, the Canadian federal government suspended the implementation of those proposed amendments.

On June 12, 2007, federal legislation was enacted implementing a new tax (the "SIFT Tax") on certain publicly traded income trusts and limited partnerships, referred to as "Specified Investment Flow-Through" ("SIFT") entities. For SIFTs in existence on October 31, 2006 (including Enterra), the SIFT Tax will become effective in 2011. If certain rules related to "undue expansion" are not adhered to ("the normal growth guidelines"), the SIFT Tax will apply prior to 2011. Under the SIFT Tax, distributions of certain types of income will not be deductible for income tax purposes by SIFTs in 2011 and thereafter any resultant trust level taxable income will be taxed at a rate that will be approximately equal to corporate income tax rates. The SIFT Tax rate is currently 29.5 percent in 2011 and 28.0 percent thereafter.

As noted above, the Trust could become subject to these changes before 2011 if it experiences growth, other than "normal growth", before that time. Under the December 15, 2006 guidelines, the Trust was considered to have experienced only "normal growth" if its issuances of new equity (which for this purpose includes Trust Units and debt that is convertible into Trust Units, but does not include non-convertible debt) did not exceed, for each of the intervening periods set forth below, a safe harbour measured by reference to the Trust's market capitalization as of the end of trading on October 31, 2006 (measured solely by the market value of the issued and outstanding Trust Units as of that date). The Trust's market capitalization as of October 31, 2006 was approximately $408 million. The intervening periods and their respective safe harbour amounts were as follows:

a) November 1, 2006 to December 31, 2007 – 40% of the Trust's market capitalization as of October 31, 2006;

b) January 1, 2008 to December 31, 2008 – 20% of the Trust's market capitalization as of October 31, 2006;

c) January 1, 2009 to December 31, 2009 – 20% of the Trust's market capitalization as of October 31, 2006;

d) January 1, 2010 to December 31, 2010 – 20% of the Trust's market capitalization as of October 31, 2006.

The December 15, 2006 guidelines provided that these annual safe harbour amounts are cumulative, and that replacing debt that was outstanding as of October 31, 2006 with new equity, whether through a Debenture conversion or otherwise, will not be considered growth for these purposes. In addition, an issuance of new equity will not be considered growth to the extent that the issuance is made in satisfaction of the exercise by another person of a right in place on October 31, 2006 to exchange an interest in a partnership, or a share of a corporation (such as exchangeable shares), for Trust Units.

On November 28, 2008, the Canadian Minister of Finance tabled a Notice of Ways and Means Motion in the House of Commons which contained proposed changes to the SIFT conversion provisions under the Income Tax Act. On December 4, 2008, the Minister released explanatory notes for the Motion which also contained revisions to the Department of Finance "normal growth" guidelines for grandfathered SIFTs. The revision to the “normal growth” guidelines has accelerated the Trust’s allowance to issue new equity without “undue expansion” and allows the Trust to issue its remaining safe harbour amount after December 4, 2008 without considering the previous timeline set out by the Department of Finance.

While the revised guidelines are such that it is unlikely they would affect the Trust's ability to raise the capital required to grow or maintain its existing operations in the ordinary course during the transition period, they could adversely affect the cost of raising capital and the Trust's ability to undertake more significant acquisitions.

There is no assurance that the Canadian federal government will not introduce other changes to the Tax Act directed at non-resident ownership which, given the Trust’s level of non-resident ownership, may result in the Trust losing its mutual fund trust status or could otherwise detrimentally affect it and the market price of the Trust Units.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses and permits for varying terms from two years and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated. In Oklahoma land sales are done privately between the individual mineral owner and Enterra.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties.

Environmental legislation in the Province of Alberta has been consolidated into the Environmental Protection and Enhancement Act, or EPEA, which came into force on September 1, 1993. The EPEA imposes stricter environmental standards, requires more stringent compliance, reporting and monitoring obligations and significantly increases penalties for violations. We are committed to meeting our responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment and will be taking such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which it operates. We believe that we are in material compliance with applicable environmental laws and regulations. We also believe that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

The Trust's operations in Canada and the United States are subject to stringent government laws and regulations regarding pollution, protection of the environment and the handling and transport of hazardous materials. These laws and regulations may impose administrative, civil and criminal penalties as well as joint and several, strict liability for failure to comply, and generally require the Trust to remove or remedy the effect of its activities on the environment at

present and former operating sites, including dismantling production facilities and remediating damage caused by the use or release of specified substances. The applicable regulatory agencies review the Trust's compliance with applicable laws and regulations. Monitoring and reporting programs, as wells as inspections and assessments for environment, health and safety performance in day-to-day operations, are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event, and remediation/reclamation programs are in place and utilized to restore the environment.

The Trust currently owns or leases, and has in the past owned or leased, properties that have been used for oil and natural gas exploration and production activities for many years. Although operating and disposal practices have been used that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by the Trust. In addition, some of these properties have been operated by third parties, whose treatment and disposal or release of petroleum hydrocarbons and wastes were not under the Trust's control, including when these properties were owned or leased by any previous owner(s). These properties and the materials disposed or released on them may be subject to joint and several, strict liability laws at the federal, state and/or provincial levels. Under such laws, the Trust could be required to remove or remediate previously disposed wastes or property contamination, or to perform remedial activities to prevent future contamination. The Trust is currently involved in several remediation projects but it does not believe these costs to be material to the Trust's operations or financial position.

During 2008, the Trust experienced three salt water spills at water handling facilities in Oklahoma. In aggregate, in excess of 200,000 bbls of produced water is moved daily to facilitate hydrocarbon production. The increased drilling activity in 2008 coupled with the prolific nature of many of these new wells has resulted in almost double the daily water production as compared to 2007. As such, the Trust took steps over 2008 to reduce the environmental risk from potential spills. These improvements included enhancements to both the alarm systems as well as to the on-site spill containment.

Additional Information Relating to the Trust

Income Streams and Distribution Policy

A portion of the cash flows generated by the assets held, directly or indirectly, by the Trust may be distributed to its Unitholders. Enterra's Trustee may, upon the recommendation of the board of EEC in respect of any period, declare payable to the Unitholders all or any part of the net income of the Trust. The Trust's primary sources of cash flow are payments of interest and repayments of principal from the Trust Subsidiaries in respect of indebtedness of each of those entities to and in favour of the Trust. The availability of cash for the payment of distributions will at all times be dependant upon a number of factors, including resource prices, production rates and reserve growth and the Enterra Board cannot assure that sufficient cash will be available for distribution to Unitholders in the amounts anticipated or at all. See "Risk Factors" in Item 3 D.

In September 17, 2007 Enterra suspended its monthly distributions in order to redirect its cash flow to the repayment of its outstanding debt. In June 2008, Enterra stated that it would extend the distribution suspension until at least November 2008 and that under the current credit facility Enterra is restricted from paying distributions while it has the second-lien facility in place. As a result, no distributions were paid in 2008.

Enterra continues to assess how cash flows generated from operations are used. In light of the current economic uncertainty, Enterra has deferred capital spending and has increased its cash position and reduced debt. Enterra will maintain a conservative approach during 2009 and assess how best to allocate cash between capital spending, debt repayment and distributions.

Enterra 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 Enterra was, until September 2007, passed on to unitholders in the form of taxable distributions. Enterra anticipates that, commencing in 2011 new tax legislation that will subject the Trust to a tax in a manner similar to corporations will decrease the amount of cash available for distribution and thus reduce any potential cash distributions to unitholders.

Series Notes

The Series Notes are unsecured debt obligations of the Operating Subsidiaries and are subordinated to all of the Trust's Senior Indebtedness. They bear interest at various annual rates, expire at various dates up to 2033 and the principal amounts of the notes vary as additional funds are loaned by the Trust to the Operating Subsidiaries or as principal repayments are made on the notes. Interest for each month is payable monthly in arrears on the 15th day of the month.

Trust Units

An unlimited number of trust units may be created and issued pursuant to the Trust Indenture. Each trust unit entitles the holder thereof to one vote at any meeting of the holders of trust units and represents an equal fractional undivided beneficial interest in any distribution from the Trust (whether of net income, net realized capital gains or other amounts) and in any net assets of the Trust in the event of termination or winding up of the Trust. All trust units rank among themselves equally and ratably without discrimination, preference or priority. Each trust unit is transferable, is not subject to any conversion or pre-emptive rights and entitles the holder thereof to require the Trust to redeem any or all of the trust units held by such holder (see "Redemption Right") and to one vote at all meetings of Unitholders for each trust unit held. In addition, in certain circumstances Unitholders will have the right to instruct the trustees of EEC Trust with respect to the voting of shares of Enterra held by EEC Trust at meetings of holders of shares of Enterra.

The trust units do not represent a traditional investment and should not be viewed by investors as "shares" in either Enterra, or the Trust. As holders of trust units in the Trust, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions.

The price per trust unit is a function of anticipated distributable income generated by the Trust and the ability of the Trust to effect long-term growth in the value of the Trust. The market price of the trust units is sensitive to a variety of market conditions including, but not limited to, interest rates, commodity prices and our ability to acquire additional assets. Changes in market conditions may adversely affect the trading price of the trust units.

The trust units are not "deposits" within the meaning of the Canada Deposit Insurance Corporation Act (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, the Trust is not a trust company and, accordingly, is not registered under any trust and loan company legislation, as it does not carry on or intend to carry on the business of a trust company.

The Trust Indenture

Enterra's principal undertaking is to issue Trust Units and to acquire and hold debt instruments, securities, royalties and other interests. The Operating Subsidiaries carry on the business of acquiring and holding interests in petroleum and natural gas properties and assets related thereto. Cash flow from the properties is flowed from the Trust Subsidiaries to the Trust primarily through (i) payments of interest and principal in respect of the Series Notes, (ii) payments of interest and principal in respect of the CT Notes, and (iii) dividends declared on the common shares of certain Operating Subsidiaries and/or redemptions of preferred shares of certain Operating Subsidiaries, which amounts are transferred from EECT to the Trust as payments of interest or principal on the CT Notes. Cash flow received by the Trust is distributed to its Unitholders on a monthly basis at the discretion of the Trust.

Issuance of Trust Units

The Trust Indenture provides that Trust Units, including rights, warrants (including so called "special warrants" which may be exercisable for no additional consideration) and other securities to purchase, to convert into or to exchange into Trust Units, may be created, issued, sold and delivered on such terms and conditions and at such times as the Trustee may determine, including, without limitation, installment or subscription receipts. Enterra's Trust Indenture also provides that the Trustee may authorize the creation and issuance of Debentures, notes and other evidences of indebtedness of the Trust, which Debentures, notes or other evidences of indebtedness may be created and issued from time to time on such terms and conditions to such persons and for such consideration as the Trustee may determine.

Special Voting Rights

The Trust Indenture allows for the creation and issuance of an unlimited number of Special Voting Rights which enable the Trust to provide voting rights to holders of securities issued by certain Trust Subsidiaries (such as exchangeable shares) that may be issued by subsidiaries of the Trust in connection with exchangeable share transactions.

Holders of Special Voting Rights are not entitled to any distributions of any nature whatsoever from the Trust. Each holder is entitled to attend and vote at meetings of Unitholders according to the terms of the instrument pursuant to which the Special Voting Rights are issued. Each holder of outstanding Special Voting Rights is entitled to that number of votes equal to the number of votes attached to the Trust Units for which the securities relating to such Special Voting Rights held by such holder are exchangeable, exercisable or convertible. Holders of Special Voting Rights are also entitled to receive all notices, communications or other documentation required to be given or otherwise sent to Unitholders. Except for the right to attend and vote at meetings of Unitholders and receive notices,

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communications and other documentation sent to Unitholders, the Special Voting Rights do not confer upon the holders thereof any other rights.

Unitholder Limited Liability

The Trust Indenture provides that no Unitholder, in its capacity as such, shall incur or be subject to any liability in contract or in tort or of any other kind whatsoever, including taxes payable, in connection with the Trust or its obligations or affairs and, in the event that a court determines that Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of the Trust's assets. Pursuant to the Trust Indenture, the Trust will indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges or losses suffered by a Unitholder from or arising as a result of such Unitholder not having such limited liability.

The Trust Indenture provides that all contracts signed by or on behalf of the Trust must contain a provision to the effect that such obligation will not be binding upon Unitholders personally. Notwithstanding the terms of the Trust Indenture, Unitholders may not be protected from liabilities of the Trust to the same extent a shareholder is protected from the liabilities of a corporation.

The activities of the Trust and the Trust Subsidiaries are conducted in such a way, upon advice of counsel, and in such jurisdictions as to avoid as far as possible any material risk of liability to the Unitholders for claims against the Trust by obtaining appropriate insurance, where available, for the operations of the Operating Subsidiaries and by having contracts signed by or on behalf of the Trust include a provision that such obligations are not binding upon Unitholders personally.

Redemption Right

The Trust Units are redeemable at any time on demand by the holders thereof upon delivery to the transfer agent of the Trust of the certificate or certificates representing such Trust Units and a duly completed and properly executed notice requiring redemption. Upon receipt of the notice to redeem Trust Units by the transfer agent, the holder thereof will only be entitled to receive a price per Trust Unit (the "Market Redemption Price") equal to the lesser of: (iii) 90% of the "market price" of the Trust Units on the principal market on which the Trust Units are quoted for trading during the 10 trading day period commencing immediately after the date on which the Trust Units are tendered to the Trust for redemption; and (iv) the closing market price on the principal market on which the Trust Units are quoted for trading on the date that the Trust Units are so tendered for redemption. Where more than one market exists for the Trust Units, the principal market shall mean the market on which the Trust Units experience the greatest volume of trading activity on the date or for the period in question, as applicable.

For the purposes of this calculation, "market price" is an amount equal to the simple average of the closing price of the Trust Units for each of the trading days on which there was a closing price; provided that, if the applicable exchange or market does not provide a closing price but only provides the highest and lowest prices of the Trust Units traded on a particular day, the market price shall be an amount equal to the simple average of the average of the highest and lowest prices for each of the trading days on which there was a trade; and provided further that if there was trading on the applicable exchange or market for fewer than five of the 10 trading days, the market price shall be the simple average of the following prices established for each of the 10 trading days: the average of the last bid and last ask prices for each day on which there was no trading; the closing price of the Trust Units for each day that there was trading if the exchange or market provides a closing price; and the average of the highest and lowest prices of the Trust Units for each day that there was trading, if the market provides only the highest and lowest prices of Trust Units traded on a particular day. The closing market price is: an amount equal to the closing price of the Trust Units if there was a trade on the date; an amount equal to the average of the highest and lowest prices of the Trust Units if

there was trading and the exchange or other market provides only the highest and lowest prices of Trust Units traded on a particular day; and the average of the last bid and last ask prices if there was no trading on the date.

The Trust will pay the aggregate Market Redemption Price in respect of any Trust Units surrendered for redemption during any calendar month by cheque on the last day of the following month. The entitlement of Unitholders to receive cash upon the redemption of their Trust Units is subject to the limitation that the total amount payable by the Trust in respect of such Trust Units and all other Trust Units tendered for redemption in the same calendar month and in any preceding calendar month during the same year shall not exceed $100,000; provided that the Trust may, at its sole discretion, waive such limitation in respect of any calendar month. If this limitation is not so waived, the Market Redemption Price payable by the Trust in respect of Trust Units tendered for redemption in such calendar month will be paid on the last day of the following month as follows: (i) firstly, by the Trust distributing Series Notes having an aggregate principal amount equal to the aggregate Market Redemption Price of the Trust Units tendered for redemption, and (ii) secondly, to the extent that the Trust does not hold Series Notes having a sufficient principal amount outstanding to effect such payment, by the Trust issuing its own promissory notes to Unitholders who

exercised the right of redemption having an aggregate principal amount equal to any such shortfall (herein referred to as “Redemption Notes”).

Notwithstanding the foregoing, the distribution of any Series Notes and the issuance of any Redemption Notes will be conditional upon the receipt of all necessary regulatory approvals and the making of all necessary governmental registrations, declarations and filings, including, without limitation, any required registration of the Series Notes or Redemption Notes, as applicable, to be distributed or issued in respect of the payment of the Market Redemption Price, and any required qualification of the Trust Indenture relating to such Series Notes or Redemption Notes, as the case may be, under the securities laws of the United States.

If at the time Trust Units are tendered for redemption by a Unitholder, (i) the outstanding Trust Units are not listed for trading on the TSX or NYSE and are not traded or quoted on any other stock exchange or market which EEC considers, in its sole discretion, provides representative fair market value price for the Trust Units, or (ii) trading of the outstanding Trust Units is suspended or halted on any stock exchange on which the Trust Units are listed for trading or, if not so listed, on any market on which the Trust Units are quoted for trading, on the date such Trust Units are tendered for redemption or for more than five trading days during the 10 trading day period, commencing immediately after the date such Trust Units were tendered for redemption then such Unitholder shall, instead of the Market Redemption Price, be entitled to receive a price per Trust Unit (the “Appraised Redemption Price”) equal to 90% of the fair market value thereof as determined by EEC as at the date on which such Trust Units were tendered for redemption. The aggregate Appraised Redemption Price payable by the Trust in respect of Trust Units tendered for redemption in any calendar month will be paid on the last day of the third following month by, at the option of the Trust: (i) a cash payment; or (ii) a distribution of Series Notes and/or Redemption Notes as described above.

It is anticipated that this redemption right will not be the primary mechanism for holders of the Trust Units to dispose of their Trust Units. Series Notes or Redemption Notes, which may be distributed in specie to Unitholders in connection with redemption, will not be listed on any stock exchange and no market is expected to develop in such Series Notes or Redemption Notes. Series Notes or Redemption Notes may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

Reporting to Unit Holders

An independent recognized firm of chartered accountants audits the financial statements of the Trust annually. The audited consolidated financial statements of the Trust, together with the report of such chartered accountants, will be mailed by the Trustee to Unitholders and the unaudited interim financial statements of the Trust will be mailed to Unitholders within the periods prescribed by Canadian securities legislation. The year-end of the Trust is December 31. The Trust is subject to the continuous disclosure obligations under all applicable securities legislation.

The Trust is subject to the reporting requirements of the U.S. Exchange Act applicable to foreign private issuers, and in connection therewith will file or submit reports, including annual reports and other information with the SEC. Such reports and other information can be inspected and copied at the public reference facilities maintained by the SEC at 450 Fifth Street, N.W., Room 1024, Judiciary Plaza, Washington, D.C. The Trust’s SEC filings and submissions are also available to the public on the SEC’s web site at www.sec.gov.

Meetings of Unitholders

The Trust Indenture provides that meetings of the Trust’s Unitholders must be called and held for, among other matters, the election or removal of the Trustee, the appointment or removal of the auditors, the approval of amendments to the Trust Indenture (except as described under “Amendments to the Trust Indenture”), the sale of the

property of the Trust as an entirety or substantially as an entirety, and the commencement of winding up the affairs of the Trust.

A meeting of the Unitholders may be convened at any time and for any purpose by the Trustee and must be convened, except in certain circumstances, if requisitioned in writing by: (i) EEC; or (ii) the holders of Trust Units and Special Voting Rights holding in aggregate not less than 5% of the votes entitled to be voted at a meeting of Enterra's Unitholders. A requisition must, among other things, state in reasonable detail the business purpose for which the meeting is to be called.

Unitholders and holders of Special Voting Rights may attend and vote at all meetings of Unitholders either in person or by proxy and a proxy holder need not be a Unitholder. Two persons present in person or represented by proxy and representing in the aggregate at least 5% of the votes attaching to all outstanding Trust Units shall constitute a quorum for the transaction of business at all such meetings. For purposes of determining such quorum, the holders of any issued Special Voting Rights who are present at the meeting shall be regarded as representing outstanding Trust Units equivalent in number to the votes attaching to such Special Voting Rights.

The Trust Indenture contains provisions as to the notice required and other procedures with respect to the calling and holding of meetings of the Unitholders in accordance with the requirements of applicable laws.

Voting of EEC trust units

There is an annual general meeting of the holders of EEC trust units. Immediately following this meeting is a Trustee meeting permitting the Trustee to vote the EEC trust units held by the Trust in the manner directed by Unitholders at the immediately preceding meeting of the Trust. Any resolution passed by Unitholders pertaining to the manner in which EEC trust units held by the Trust are to be voted by the Trustee in respect of a particular matter which is to be put forth to the holders of EEC trust units for vote at a contemplated meeting (including by written resolution) of holders of EEC trust units, shall be deemed to be a direction to the Trustee in respect of the EEC trust units held by the Trust to, as applicable, either vote such EEC trust units in favor of or in opposition to, or to vote or with-hold from voting in respect of such matter in equal proportions to the votes cast by Unitholders in respect of the matter, and the Trustee is obligated to vote, in respect of such matter if put forth to the holders of EEC trust units at a meeting of such holders, the EEC trust units held by the Trust in accordance with such direction.

Exercise of Voting Rights

Enterra's Trustee is prohibited from authorizing or approving:

- any sale, lease or other disposition of, or any interest in, all or substantially all of the assets owned, directly or indirectly, by the Trust, except in conjunction with an internal reorganization of the direct or indirect assets of the Trust, as a result of which the Trust has substantially the same interest, whether direct or indirect, in the assets as the interest, whether direct or indirect, that it had prior to the reorganization;