Enterra
ENERGY TRUST

2005

ANNUAL REPORT

MANAGEMENT TEAM

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PRESIDENT & CEO

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VICE PRESIDENT, OPERATIONS & ENGINEERING

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MANAGER, HUMAN RESOURCES

Karen Hutson
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CORPORATE PROFILE

Enterra Energy Trust is an oil and gas income trust based in Calgary, Alberta. Enterra's focus is the acquisition and development of petroleum and natural gas reserves in North America. Enterra's trust units are listed for trading on the NYSE (symbol: ENT) and on the TSX (symbol: ENT.UN).

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- In 2005 Enterra Energy Trust increased its exit production rate by 28% and its proven and probable reserve base by 102%.
- The Trust increased its monthly distributions from US$0.14 to US$0.18 during 2005, providing a return of 10% to a unitholder invested at the beginning of the year.
- Through a concerted effort to provide a more balanced portfolio and to take advantage of high prices in the extremely tight natural gas market in North America, the Trust moved its oil and gas mix from 80% oil and 20% gas to 60% oil and 40% gas in 2005.
- Through its strategic farm-in partners, Enterra saw 60 wells drilled on its undeveloped acreage at no cost or risk to the Trust. Our partners drilled an additional 20 wells on our lands in the first quarter of 2006.

Enterra's

2005 HIGHLIGHTS

- Through a series of acquisitions in 2005 – the most important of which was High Point Resources Inc. – the Trust increased its reserve base to 19 mmboe proven and probable reserves.
- The acquisition of Altex Energy Corporation in Oklahoma, announced in December 2005, netted the Trust an additional 6,300 boe/day and a further approximate 70% increase to its proven plus probable reserve base.
- Enterra is now a completely independent entity. At the beginning of 2005, the Trust received operational and accounting services from JED Oil Inc. under a technical services agreement. By year-end, Enterra had 57 employees managing every aspect of its business, and terminated its services agreement with JED Oil Inc. on January 1, 2006.
- At the end of the first quarter of 2006, the Trust employed 98 people and had established a US divisional headquarters in Carney, Oklahoma.
- Enterra Energy Trust became a New York Stock Exchange listed company on February 9th, 2006 – ensuring maximum liquidity for unitholders.

MESSAGE FROM THE PRESIDENT

E. Keith Conrad
PRESIDENT & CEO

Dear Fellow Unitholders:

Enterra Energy Trust is pleased to submit its Annual Report for 2005, a year of dramatic growth and substantial change. The accomplishments of 2005 and early 2006 have placed Enterra in a stronger position than ever before to grow reserves and production - the backbone of sustainable monthly cash distributions to unitholders. As this report goes to press, Enterra has just closed the acquisition of approximately 6,300 boe/day located in the State of Oklahoma. The Oklahoma transaction, measured by any of the traditional metrics applied to oil and gas trusts, is significantly accretive – benefiting Enterra and ultimately, you, the unitholders. This latest acquisition is the culmination of a year of hectic activity that has seen Enterra grow in daily volumes from an average daily production rate of approximately 7,000 boe/day at year end in 2004 to approximately 16,000 boe/day at the end of March 2006.

From a strategic perspective, Enterra's management team took action to establish the critical mass necessary to support a sustainable income distribution structure. It adopted a business plan with goals based on five "S's": **solid production base, strong balance sheet, strategic relationships** and **superior staff** – all supporting a business characterized by **sustainable distributions.**

Solid Production Base

Enterra exited 2005 producing 9,282 boe/day, an increase of 28% from the 2004 exit rate. As a result of the acquisitions made in 2005 and early 2006, Enterra's portfolio is more balanced between oil and natural gas. Upon completion of the Oklahoma acquisition, Enterra's portfolio of assets will be comprised of approximately 60% natural gas and 40% oil. With the increase in the natural gas component of our portfolio, we will significantly lower unit operating costs. Moreover, with the development opportunities available on these acquired lands we can, in conjunction with our farm-outs, clearly replace reserves and increase production. The benefits of these developments will become more and more apparent as we progress through 2006.

Strong Balance Sheet

The need to strengthen Enterra's underlying business became evident in 2005 and thus we have moved aggressively to address this need. Faster than anticipated production declines, widening light/heavy oil price differentials, higher operating costs and unanticipated legacy costs all combined to squeeze Enterra's financial performance by mid 2005. Distributions of 94% of funds from operations are too high for long-term stability. The acquisition of High Point Resources Inc. and the Oklahoma transaction were key steps taken to address the situation. A strategic direction grounded on the following principles is being pursued:

- A plan for portfolio rationalization to increase netbacks by improving product quality and lowering costs;
- Strategic acquisitions at competitive prices, characterized by longer lived reserves;
- Strong financial management including broader banking and capital market relationships; and
- An inventory of drilling opportunities to be developed by our farm-out partners.

Strategic Relationships

Reserve replacement is a key focus of Enterra, as it is with any other oil and gas trust. One of Enterra's primary strategies to effect reserve replacement is through farm-outs to exploration and development companies who develop the substantial undeveloped lands that Enterra owns or leases. JED Oil Inc., through its agreements with Enterra, continues to develop key projects in west central Alberta and northeast British Columbia. At the time the High Point Resources, Inc. acquisition closed in August 2005, it included more than 135,000 net acres of undeveloped land with more than 120 identified drilling locations. Under the farm-out arrangements, JED Oil Inc. pays 100% of the cost of each well drilled and earns 70% of the production. Enterra has no exposure to drilling costs or dry holes, but benefits from today's higher energy pricing environment in the form of a retained 30% interest in the resulting production and revenue. Enterra entered into a similar arrangement with Petroflow Energy Ltd. to develop the undrilled land in Oklahoma. We are currently looking to expand utilization of key relationships to achieve specific goals, which include risk reduction and capital conservation as well as accessing key technical expertise and achieving effective cost control.

Superior Staff

Perhaps the most profound change in Enterra since the issuance of the 2004 Annual Report lies within the realm of human resources, business practices and corporate governance. A year ago Enterra had only a handful of employees, as most functions were outsourced. By the end of 2005 Enterra had 57 employees, and since the addition of Altex Energy Corporation, our Oklahoma operating company, Enterra has 98 people dedicated to maximizing the profitability of our existing assets and looking for ways to grow and improve Enterra's business. Enterra is being managed and operated by individuals who are employed by Enterra and are responsible to its owners: you, the unitholders. We now have the resources in place to utilize in-house expertise both in the field and at Enterra's headquarters as well as in our new regional office in Carney, Oklahoma.

To ensure our employees' focus on Enterra's assets and to align our employees' interests with our unitholders' interests, we have introduced a performance incentive system for 2006 that focuses on:

- Achieving our distribution goals;
- Enhancing our reserves/unit metric; and
- Improving Enterra's netback per boe.

Long-term incentive plans are oriented to ownership and savings through Enterra trust units, thus paralleling unitholder interests.

Sustainable Distributions

"Sustainable Distributions" is the mantra of our business strategy. Each of the other four "S's": **solid production base, strong balance sheet, strategic relationships and superior staff** serves the purpose of focusing Enterra on having a sustainable distribution program. Our business plan is intended to provide a solid foundation for long-term distribution stability and a measured growth in distribution rate. I firmly believe that this goal is one that can be easily identified with and understood by employees, management and unitholders alike. None of us can predict the future with certainty, but we can all make plans and focus on execution in the light of a single clear objective. Enterra's clear objective is to have a sustainable and growing distribution program that will also lead to appreciation in unit value.

Outlook for 2006

As we are well into the second quarter of 2006, we can look back and recognize that Enterra is a much stronger entity. We have a plan in place and are well on the way to reaping some of the fruits of the plan's execution. We have established a core operating area in Oklahoma to complement our locations in Western Canada and we continue to focus on creating operating efficiencies and critical mass in each respective area. Having said that, there remains work to be done. Extending the Reserve Life Index beyond the current 5.8 years will remain a goal. Developing a relationship with one or two additional "farm teams" is critical to ensure that we can maximize the value of our undeveloped land and harvest those untapped reserves in an aggressive manner, while still being efficient with our capital. As always, we will focus on reducing our operating costs and replacing depleted assets with low operating cost assets. We will continue to provide our unitholders and the market with clear, consistent and timely communications on our mission and progress. As these objectives are met, Enterra will become stronger and the growth of our distributions more secure.

Before closing, I would like to personally thank Reg Greenslade, who has stepped down as Chairman of the Board, and who has been a consistent and tireless advocate of Enterra since its inception. It is our challenge to pick up where he has left off and move Enterra forward. At the same time I, along with other members of our Board, welcome Joe Vidal, Enterra's new Chairman of the Board. I would like to offer my thanks to our excellent management team and group of employees who bring enthusiasm, skill and dedication to their work daily. I would also like to extend thanks to the Board of Directors for their involvement and support over the last year. Finally, I want to thank you, our unitholders, for your vote of confidence in our business plan and its execution backed by your investment in Enterra.

As stated in the opening of this letter, never before has Enterra been in a better position as a sustainable income trust. We still have much to accomplish but, we have the resources and the determination to profitably grow Enterra's asset base and, over time, to grow our monthly distributions and unit value.

E. Keith Conrad
PRESIDENT & CEO

2005 SUMMARY *For Year Ended December 31, 2005, 2004 and 2003*

	2005	2004 (Restated (1))	2003 (Restated (1))
FINANCIAL			
Production revenue	$ 157,743	$ 108,293	$ 72,097
Funds from operations	$ 70,545	$ 50,242	$ 30,693
Per unit	$ 2.39	$ 2.23	$ 1.64
Cash provided by operating activities	$ 68,120	$ 42,345	$ 20,971
Per unit	$ 2.31	$ 1.88	$ 1.12
Net earnings	$ 970	$ 14,027	$ 5,430
Per unit	$ 0.03	$ 0.62	$ 0.29
Total assets	$ 611,543	$ 221,128	$ 116,705
Total bank debt, note payable & capital lease obligations	$ 102,101	$ 47,315	$ 38,129
Unitholders' equity	$ 289,709	$ 114,971	$ 44,545
SHARES AND UNITS OUTSTANDING			
Weighted average number of units outstanding in year	29,533,577	22,518,373	18,751,634
Number of units outstanding at the end of year	36,504,416	25,426,800	18,955,960
Number of exchangeable shares outstanding at end of year	1,744,104	553,214	1,995,596
PRODUCTION			
Average daily production (boe/day)			
Oil production (bbls/day)	5,453	5,821	3,862
Gas production (mcf/day)	13,729	6,817	6,972
Total production(boe/day)	7,741	6,957	5,024
Exit production (boe/day)			
Oil production (bbls/day)	5,476	5,905	4,890
Gas production (mcf/day)	22,836	8,118	9,420
Total production (boe/day)	9,282	7,258	6,460
Average field prices during year			
Oil ($/bbl)	$ 58.11	$ 43.00	$ 39.12
Gas ($/mcf)	$ 8.40	$ 6.69	$ 6.65
PER BOE INFORMATION			
Revenue	$ 55.83	$ 42.53	$ 39.32
Production expenses	$ 11.55	$ 9.25	$ 6.96
Royalties	$ 12.77	$ 9.63	$ 9.63
Operating netbacks	$ 31.51	$ 23.65	$ 22.73
General and administrative	$ 3.66	$ 1.75	$ 1.85
Interest	$ 1.67	$ 0.87	$ 0.95
Corporate netbacks	$ 26.18	$ 21.03	$ 19.93
Amortization of deferred charges	$ 0.01	$ 0.01	$ 0.14
Financial derivative loss (gain)	$ (0.13)	$ 1.25	$ –
Depletion and depreciation	$ 29.05	$ 14.13	$ 12.71
Goodwill impairment	$ 3.27	$ –	$ –
Foreign exchange	$ (0.25)	$ –	$ –
Earnings from operations	$ (5.78)	$ 5.63	$ 7.08
Restructuring and re-organization charges	$ –	$ –	$ 3.14
Income tax	$ (6.10)	$ 0.07	$ 1.16
Net earnings before non-controlling interest per boe	$ 0.32	$ 5.56	$ 2.78
Non-controlling interest	$ (0.01)	$ 0.16	$ (0.14)
Net earnings per boe	$ 0.33	$ 5.40	$ 2.92

	2005	2004	2003
RESERVES			
Proved reserves	14,294.9	7,385.4	6,142.9
Probable reserves	4,737.2	2,023.9	2,291.9
Total reserves	19,032.1	9,409.4	8,434.8
Finding costs: Proved reserves	$ 42.88	$ 17.83	$ 17.54
Proved plus probable reserves	$ 28.36	$ 12.86	$ 13.46
Recycle ratio	1.10	1.84	1.69

(1) Restated for the adoption of EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts". See note 3 of the 2005 notes to consolidated financial statements.

ORGANIZATIONAL SUMMARY

2005 was a year of dramatic change in the organizational structure and management of Enterra Energy Trust.

At the same time as Enterra announced its intention to acquire High Point Resources Inc. in June 2005, we also acquired a new executive team. In the third quarter, the new team began an ambitious initiative to staff-up the Trust to the point where we manage operations and finances with our own dedicated employees. From starting the year with a handful of staff, Enterra ended 2005 with 57 full-time employees (later expanded to 98 at March 31, 2006), based out of our own Head Office in Calgary, our field offices and our new US office in Carney, Oklahoma. This allowed us to terminate our operating and accounting services agreement with Jed Oil inc. as of January 1, 2006.

Strategic RELATIONSHIPS

This intense period of rapid growth and increasing maturity led to two notable consequences:

- the resignation of Mr. Reg Greenslade as Chairman of the Board effective March 31, 2006, to allow for greater Board independence; and
- the Trust's listing on the New York Stock Exchange (under the trading symbol ENT), to enhance our market visibility and to increase the liquidity of our units.

Third-Party Relationships

In 2005, Enterra actively pursued strong relationships with third parties to enable us to exploit our lands with no capital or exploratory risk. The Trust's carried interest under these arrangements is intended to help ameliorate natural declines in our production profile; Enterra at all times maintains full operatorship and control of our assets, allowing us to leverage capital while taking advantage of outside technical expertise.

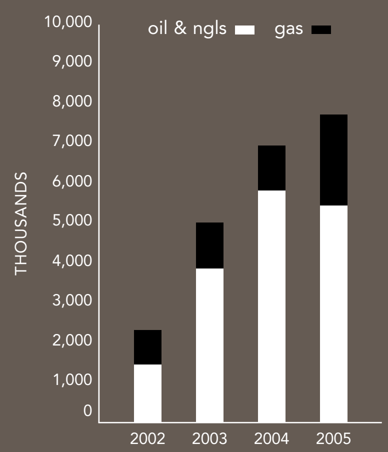
Under our first third-party relationship, farm-in partner JED Oil Inc. developed our assets in eastern Alberta in 2005 and, in late 2005 and early 2006, also started drilling in other key areas in Alberta and British Columbia that we acquired through High Point Resources Inc.

We signed a similar arrangement with Denver-based company PRB Gas Transportation Inc., to develop the coal bed methane assets held under our Wyoming-based subsidiary, Rocky Mountain Gas Inc.

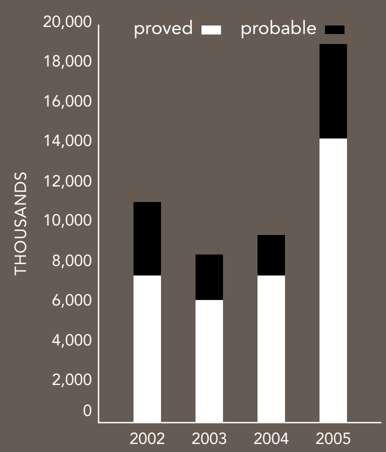
The agreement, now terminated, saw over 40 development wells drilled on Enterra lands at no cost whilst providing additional production and reducing future exploitation risk.

More recently still, in early 2006, we signed an agreement with Petroflow Energy Ltd. of Calgary to farm-in and drill on our newly acquired Altex Energy Corporation assets in Oklahoma.

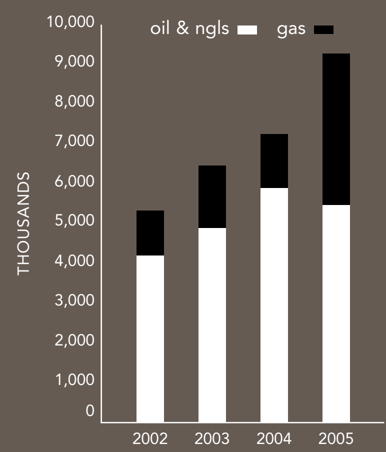
2005 HIGHLIGHTS



2002-2005 AVERAGE PRODUCTION (BOE/DAY)



2002-2005 RESERVES (MBOE)



2002-2005 EXIT PRODUCTION (BOE/DAY)

BUSINESS ENVIRONMENT

Commodity Prices

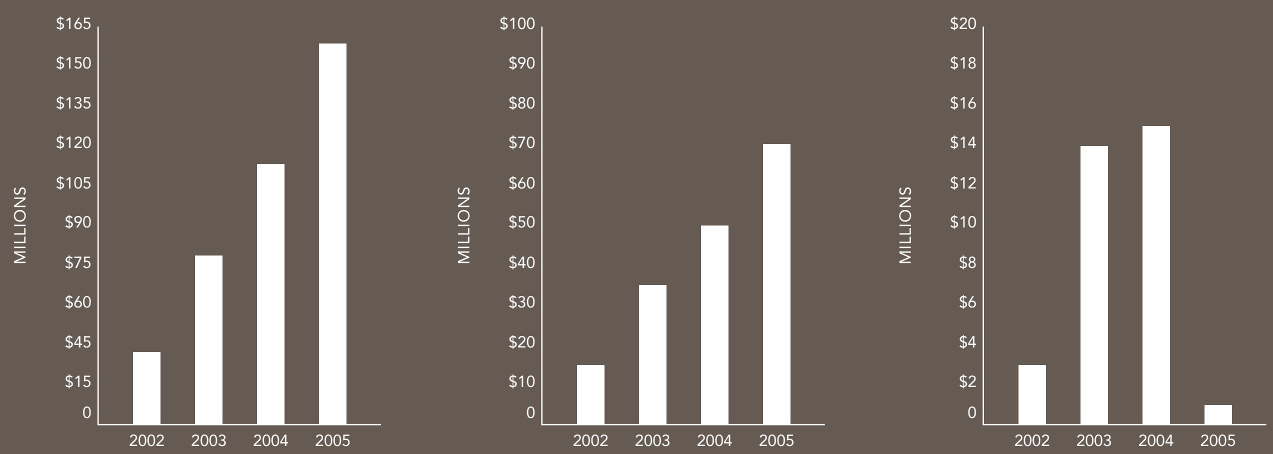
We believe that the North American energy market will continue to be supply-sensitive, particularly with respect to natural gas.

Globally, the demand for hydrocarbon energy sources has continued to be strong despite the run-up of prices over the last two years. Even natural gas, traditionally priced according to local supply-and-demand conditions, appears now to be affected by shortages elsewhere in the world.

For example, a Russian gas pipeline dispute in western Asia now seems to be a concern for natural gas markets in North America. As world dependence on liquefied natural gas supplies increases, globalization will become the standard market condition for natural gas, just as it is for oil today.

An unusually warm winter in North America was welcome at a time when the 2005 hurricane season severely damaged natural gas and oil infrastructure. We believe there will be some price cycling up and down in mid-year but, overall, commodity prices will remain robust, since it seems that today's skittish market behavior results from a genuine concern about the sources of critical energy supply.

To protect against short-term downside cycles, we have put in place a series of price collars with strong floors and high ceilings to protect about 50% of Enterra's production. Most of these collars are low- to no-cost to the Trust, and will help us meet our goal of sustainable distributions.



REVENUE: 2002-2005 (CDN $)

FUNDS FROM OPERATIONS 2002-2005 (CDN $)

EARNINGS FROM OPERATIONS 2002-2005 (CDN $)

Staffing and Services

After nearly two decades in a low-price environment, the oil and gas industry across North America finds itself with a significant shortage of skilled workers.

It has proven to be a challenge for Enterra to attract and retain qualified staff. In response, we have established very competitive salary and benefits packages in order to build our internal expertise. We are also developing strategic partnerships with critical service suppliers and consultants to extend the Trust's reach into important business areas.

Other challenges over the past year have included rising costs for labour, services and equipment, and difficulties in procuring required equipment – resulting in delays in executing some projects.

OPERATIONAL SUMMARY

Enterra Energy Trust and its partners drilled over 60 new wells on Trust lands during 2005, and an additional 20 wells in the first quarter of 2006.

Enterra's carried working interest in these wells varies between 30% and 50%; we did not risk our capital to achieve this result.

A net of approximately 600 boe/day additional production was brought on by March 31, 2006, and a further 400 boe/day is anticipated during April 2006. Continued development during 2006 will provide additional production.

Assets in the Western Canada Sedimentary Basin

Enterra's core areas include a variety of assets in the Western Canada Sedimentary Basin in the Provinces of Alberta and British Columbia, including major producing fields and areas in:

Solid

PRODUCTION

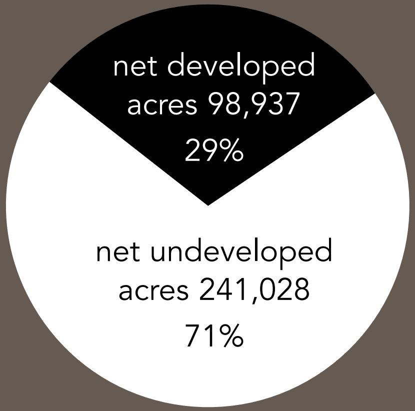
Clair, Alberta

The Clair property is located seven miles north of the city of Grande Prairie, Alberta. Enterra's assets include a 100% working interest in 3,520 acres of land, 23 producing oil wells and an oil treating facility. Gas is conserved and processed at the Encana Sexsmith gas plant.

Production is primarily from the Doe Creek (Dunvegan) formation, with a small amount of gas production from the Charlie Lake and Halfway formations. Production is light, 44-degree API gravity crude oil and solution gas from the Doe Creek oil pool. One additional, dually completed Charlie Lake and Halfway gas well also produces. At December 2005, the field was producing a combined 1,950 bbl/day of oil and 1,400 mcf/day of raw solution gas on a working interest basis before royalties.

To date, Enterra has drilled or re-completed 29 wells for oil and seven wells for water injection. We are currently water-flooding the pool to optimize the recovery of hydrocarbons, and have no further drilling plans for it.

LAND HOLDINGS
(at December 31, 2005)



Developed acres	CANADA	US	TOTAL
Gross	143,316	50,878	194,194
Net	85,314	13,623	98,937
Undeveloped acres			
Gross	241,645	127,090	368,735
Net	156,859	84,169	241,028
Total acres			
Gross	384,961	177,968	562,929
Net	242,173	97,792	339,965

Total remaining net proved reserves assigned to the Doe Creek 'A' (Dunvegan) pool are 1,141 mbbl of oil, 955 mmcf of gas and 67mbbl of natural gas liquids.

Enterra also owns and operates a central oil treating facility at Clair, which is connected into the Pembina Peace Pipeline.

Provost-Alliance-Wainwright, Alberta

The Provost-Alliance-Wainwright producing area is located near of the town of Provost, Alberta. These eastern Alberta assets are generally quite mature and include Alliance, Sounding Lake, Hansman Lake, Halkirk, Monitor, Provost Cummings "Y" Unit and Wainwright. Enterra's assets include an average working interest of 80% in 84,454 gross acres of land, as well as 371 producing oil and gas wells.

Enterra's production comes primarily from the Dina, Cummings and Belly River formations. Our December share of production for the entire area was 1,513 bbl/day of oil and NGLs, and 1,563 mcf/day of gas on a working interest basis before royalties. In order to maximize oil production and lower operating costs, Enterra continues to optimize down hole pumps and upgrade or consolidate oil batteries to handle higher volumes of total fluid and injection water. We currently conserve solution gas at most of the oil batteries.

In 2004 and 2005, Enterra – with its partner JED Oil Inc. – drilled 21 oil wells in the Cummings "Y" Unit to bring the total number of oil producers to 37. In order to lower operating costs and optimize reserve recovery from the Cummings "Y" pool, Enterra constructed a central facility to ship clean oil and re-inject produced water into the pool. We anticipate significant field performance improvements as a result of the full activation of the water flood in 2006.

Enterra has net proved reserves in the Provost-Alliance-Wainwright area of 1787 mbbl of oil, 2,450 mmcf of natural gas and 32.4 mbbl of natural gas liquids.

In this east Alberta producing region, many of the assets are subject to significant electricity and fuel requirements. In 2005, high commodity prices and constrained supply negatively affected our operating costs and reduced our margins.

Princess, Alberta

Acquired from Rocky Mountain Energy Corp. in 2004, the Princess area assets are now operated under Enterra Production Corp., a wholly owned subsidiary of Enterra Energy Trust.

Enterra's average working interest in the Princess area is 54% in 27,747 acres. Production is primarily from the Sunburst and Pekisko formations. Sunburst production consists of gas and 23 degree API crude oil. The Pekisko production consists of gas and 27 degree API crude oil. Enterra also has an average working interest of 50% in 3,040 acres in the Tide Lake area. Production, consisting of 27 degree API oil, is from the Pekisko formation. In December 2005, total area working interest production before royalties was 516 bbls/day of oil and NGLs, and 1,206 mcf/day gas.

The total net proved remaining reserves are 524 mbbl of oil, 1,163 mmcf of natural gas and 17 mbbl of natural gas liquids.

Sylvan Lake, Alberta

The Sylvan Lake property is located 24 miles west of the town of Red Deer, Alberta. Enterra's assets include an average working interest of 76% in 4,312 gross acres of land, as well as 25 producing oil wells.

In 2005, Enterra completed the development of 40-acre spacing wells in the Pekisko G pool, and drilled four subsequent oil wells on 20 acre spacing. At December 2005, the field was producing 553 bbls/day of 14 degree API oil with 413 mcf/day of associated gas. Production is processed at Enterra's operated central treating facility. Non-associated gas is conserved at the Husky Sylvan Lake gas plant. Clean oil is trucked from the facility to sales.

Total proved remaining reserves are 981 mbbl of oil, 991 mmcf of natural gas, 52 mbbl of natural gas liquids.

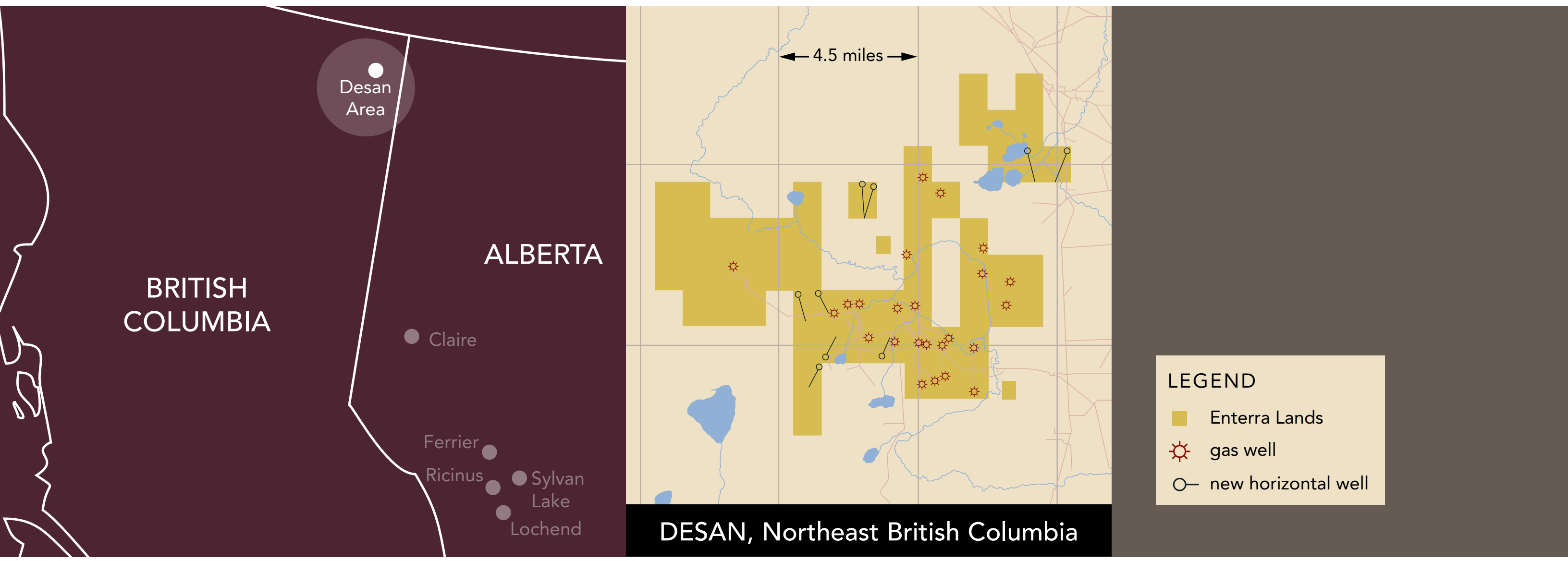
Assets Acquired Through High Point Resources Inc.

In August 2005, Enterra Energy Trust acquired High Point Resources Inc., which brought with it a variety of major producing fields and areas in:

Desan, Northeast British Columbia

The Desan property – which Enterra operates – is located approximately 75 miles northeast of Fort Nelson, British Columbia, in the centre of a well-established gas-producing region commonly referred to as Greater Sierra. The majority of the drilling, seismic and project construction is carried out during the winter months.

The primary producing formation is the regional Jean Marie Formation at 1,300 meters, which we are developing with horizontal well-bores using under-balanced drilling methods. Enterra's average net production December 2005 was 7.3 mmcf/day of natural gas and 54 bbls/day of oil



DESAN, Northeast British Columbia

and natural gas liquids produced from a total of 20 wells. We hold 100% working interest in all wells and infrastructure, and operate all wells and compression facilities. Total proved reserves are 15.8 bcf of natural gas and 104 mbbl of NGLs and total proved plus probable reserves of 20.3 bcf of natural gas and 134 mbbl of NGLs to the Desan property.

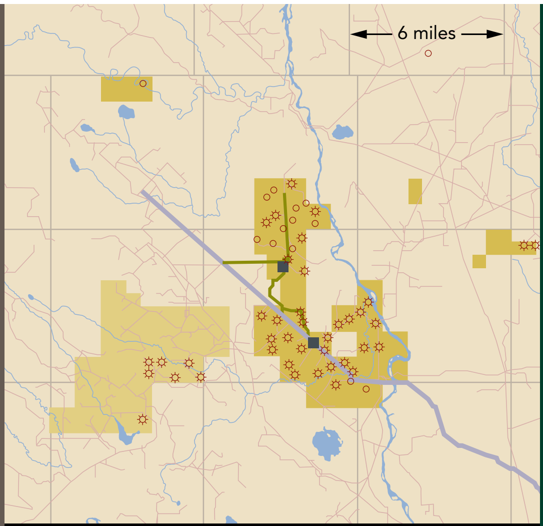
During the winter of 2005, Enterra and our farm-in partner JED Oil Inc., drilled nine wells on the Desan property. A short and warm winter season made operations difficult and curtailed the larger program we had originally planned.

Enterra has approximately 37,367 acres of undeveloped land at Desan and nearby similar properties at Kotcho and Peggo Pesh. On the basis of industry practice for exploitation of the Jean Marie, these lands could support more than 50 additional wells.

Ferrier, Alberta

The Ferrier property is located in west central Alberta. Enterra operates as well as conducts joint venture operations with other companies in the area to produce and drill multi-zone liquids-rich natural gas formations at depths ranging from 2,400 meters to 2,800 meters. The majority of the area offers year-round access for drilling, seismic and construction projects.

Enterra owns various interests in 51 sections of land, mainly developed at two wells per section for gas. Since acquiring High Point, the Trust has farmed out the drilling of 15 wells, nine of which were drilled in late 2005; eight of the nine wells are now on production while one awaits tie-in. We are in the planning and approval stage for further drilling of up to 15 additional wells, and anticipate that drilling will begin later in 2006.



FERRIER, Alberta

Enterra owns infield compression and dehydration facilities and pipelines in proportion to its well interests. The raw gas is processed at third-party processing facilities to remove natural gas liquids. To bring on gas constrained by the existing gathering system capacity, Enterra oversaw the construction of 15 km of gathering pipelines and a compression facility (commissioned on March 24, 2006) capable of 9 mmcf/day.

Enterra's average net production at December 2005 was 4.4 mmcf/day of natural gas and 250 bbls/day of oil and natural gas liquids. Total proved reserves are 13.7 bcf of natural gas and 799 mbbl of oil and NGLs.

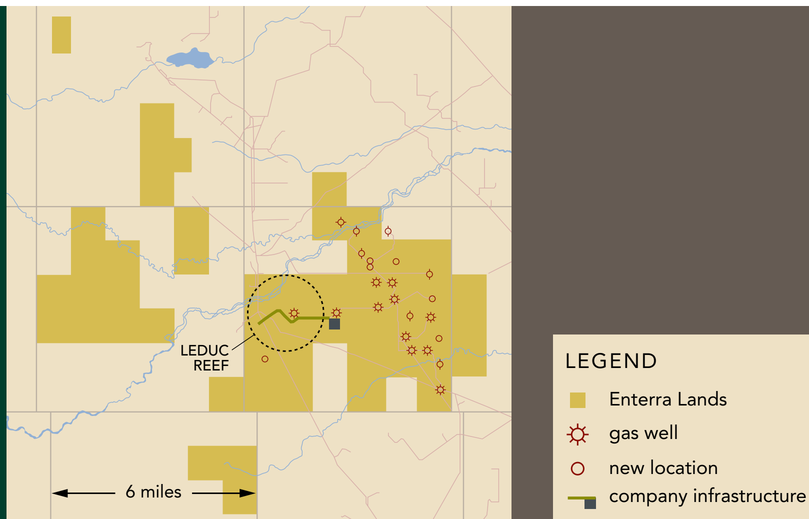
Ricinus, Alberta

The Ricinus property is located in west central Alberta, south of the Ferrier area. Enterra – which operates the property – has interests varying from 6.5% to 85% in 43 sections of land.

Ricinus is a major exploitation area for Enterra, targeting sweet light oil and gas to depths of 3,000 meters. Since acquiring High Point, Enterra has drilled seven wells under farm-in terms; six are on production, and one was abandoned. Enterra has also made significant modifications to an existing compression facility to allow maximum throughput of the new production.

Enterra's average net production for December 2005 was 1.3 mmcf/day of natural gas and 104 bbls/day of oil and natural gas liquids. Total proved reserves are 3.9 bcf of natural gas and 205 mbbl of oil in the Ricinus shallow horizons.

Within the Ricinus area, Enterra has a 50% interest in a deep, high productivity Leduc well that tested at rates up to 7 mmcf/day and is thought to be capable of significantly higher rates. Production is anticipated to begin in April 2006. Additional proved plus probable gas reserves of 4.5 bcf are assigned to this well. One or two additional drill targets of a similar nature may exist on Enterra lands.



RICINUS, Alberta

Lochend, Alberta

The Lochend property is located west central Alberta south of Ricinus. Enterra has a 21% interest in 16 sections of land.

The property has undergone extensive development over the last three years, with 29 wells currently producing. The property is now being developed at four wells per section for light oil, natural gas and natural gas liquids from the Cardium formation at a depth of approximately 2,400 meters. The area has year-round access for drilling, seismic and construction projects. Enterra owns infield oil and gas treatment facilities and pipelines in proportion to its well interests. The raw gas is processed at third-party processing facilities to remove natural gas liquids. Enterra's average net production for December 2005 was 0.7 mmcf/day of natural gas and 108 bbls/day of oil and natural gas liquids.

Total proved reserves are 760 mmcf of natural gas and 96.4 mbbl of oil and NGLs, and total proved plus probable reserves of 981 mmcf of natural gas and 125 mbbl of oil and NGLs are assigned to the Lochend property.

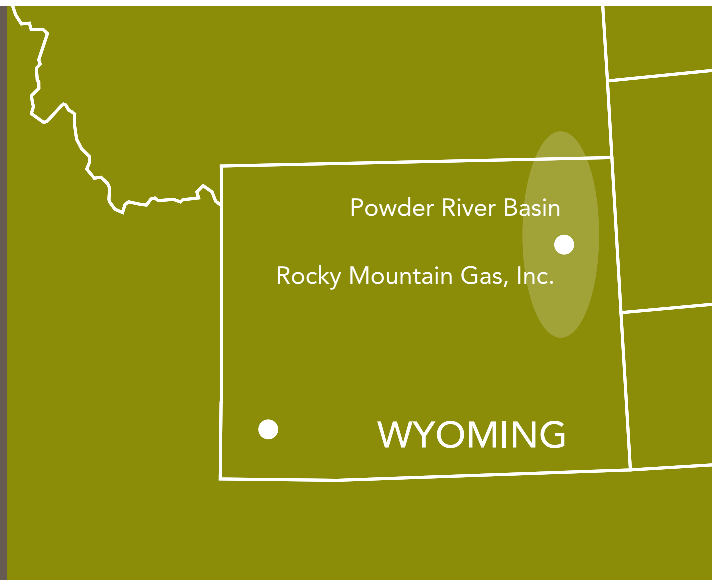
Assets Acquired Through Rocky Mountain Gas Inc.

In June 2005, Enterra acquired Rocky Mountain Gas Inc. (RMG), a Wyoming-based coal bed methane producer with assets in the Powder River Basin in Wyoming and Montana and in the Oyster Ridge area of western Wyoming. RMG has rights to 89,934 net acres of land, most of which remains undeveloped and prospective for coal bed methane.

The company's total production was approximately 2.9 mmcf/day net at December 2005, primarily from the area surrounding:

Gillette, Wyoming

Through a farm-in agreement with PRB Gas Transportation Inc. of Denver, Colorado, PRB successfully drilled and completed 26 wells in the Gillette area, of which all are currently producing



gas, or are or soon will be in a de-watering phase. Under this agreement, PRB had the right to earn 50% of new production and up to 50% interest in certain lands by expending 100% of development costs. (PRB chose to terminate this arrangement on March 20, 2006, after drilling a total of 40 wells.)

The most promising growth area for RMG land lies in exploiting the deeper coals below the well-known Wyodack coal in the Gillette region, which is now nearing full depletion. At the end of March 2006, RMG had one pod of 12 wells de-watering the Danner coal and showing initial signs of annular gas pressure. The company hopes that this pod will begin to produce commercial gas in 2006, after which we can initiate a substantial follow-up program.

South of Gillette, Enterra is currently drilling a second pod of 19 wells into the similar, deeper Moyer coal. Once drilling is complete, we will begin de-watering to assess if commercial gas production is possible. We anticipate completing this assessment in late 2006, with a follow-up program consisting of up to 40 wells.

We will pursue several other coal bed methane opportunities across our asset-base during the balance of 2006.

Assets Acquired Through Altex Energy Corporation

Enterra announced in December 2005 that we had entered into definitive agreements to acquire substantial assets of approximately 6,300 boe/day in the State of Oklahoma. Once complete, the acquisition of Altex Energy Corporation will include approximately 28,000 net developed acres and 25,000 net acres of undeveloped lands. Finalized reserves assessments are still in progress.

Carney, Oklahoma

Current and anticipated production from Altex comes from the Hunton Group carbonate formations near Carney, Oklahoma, and is derived through a de-pressuring of the formation via water production followed by hydrocarbon production. The Hunton is exploited at depths of approximately 1,500 metres using long,

multi-leg horizontal wells. Very high rates of water production, over 100,000 barrels per day, are handled through an efficient multi-well pad drilling and injection site strategy. A single water disposal well can handle all the water from at least eight associated producers. The company manages its own distribution and gathering pipelines, electrical supply and field operations, resulting in a remarkably efficient operation. Overall hydrocarbon lifting expenses including water disposal are on the order of US$5/boe.

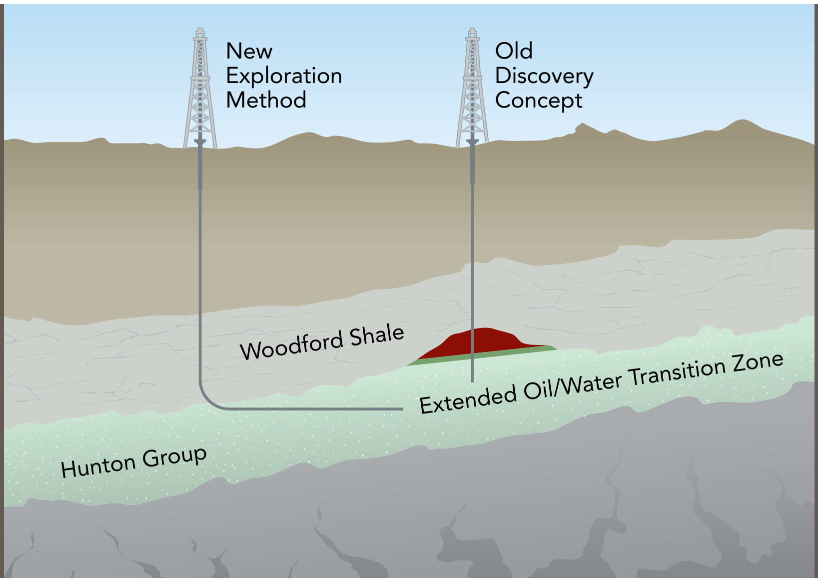
The production from the assets is roughly 80% liquids rich natural gas and 20% light sweet oil. Prices received for both gas and oil are very competitive, with gas receiving a slight discount to Henry Hub and oil a small premium to WTI. Oil is trucked to market and gas is readily processed in third-party gathering systems. Various areas along the exploited trend exhibit different ratios of oil versus gas production, with some nearly all oil and others mostly gas. Peak well production rates (after a period of inclining rates) reach as high a several hundred boe/day. Peak rates are maintained for up to two years and then decline similar to conventional wells.

Altex's experienced staff of approximately 25 people joined Enterra effective March 23, 2006; Enterra will now continue to operate all existing production, gathering and water disposal facilities. Enterra also signed a farm-out agreement with Petroflow Energy Ltd. of Calgary to exploit the undeveloped Hunton prospects aggressively in 2006. Petroflow will bring a variety of expertise to the exploitation effort, including drilling and completion specialists, and the company's field staff will be co-located at Enterra's new office in Carney, Oklahoma.

Underlying all the developed and undeveloped lands in the Altex asset-base is the Woodford Shale, which may be a shale gas target similar to the Barnett Shale in Texas. We intend to test this concept over the long term.

Traditional Hunton Group fields incorporated classic structural and stratigraphic traps and were exploited with vertical wells.

The Altex Energy exploitation strategy uses long, multi-lateral, horizontal wells and rapid de-watering of the wet reservoir. Lower pressures allow release of volatile oil and associated natural gas from tighter reservoir rock, which can then be produced economically.



Other Assets

Enterra Energy Trust also has – in Alberta, British Columbia, Saskatchewan, Wyoming, Montana and Oklahoma – an inventory of minor producing assets, minor royalty interests, and various prospects of an exploitation and exploration nature on undeveloped lands.

The development of these latter assets could significantly increase the size of our existing production and reserve base.

HEALTH, SAFETY AND ENVIRONMENT (HSE)

In 2005, we recognized that Enterra's base producing fields and facilities are older assets that require constant attention for health, safety, environmental and regulatory compliance. At the same time, we know that our newer development programs are subject to changing modern compliance requirements.

To ensure Enterra's employees are safe in their work and working safely – and that our impact on our neighbours is minimized – we initiated a systematic program of "facility health checks" with the help of a third-party engineering firm in fall 2005. These checks identify any short-comings that need to be rectified or improvements that can be made to current practices to improve both safety and efficiency.

We also began the process of extensively updating Owner User and Integrity programs as part of new regulations regarding pressure vessels and electrical equipment. This update will include rigorous procedures and the requirement for systematic annual inspections of all facilities.

Superior STAFF

In addition, as of mid-March 2006, Enterra employs a full-time HSE Representative whose responsibilities will include maintenance of all HSE records, development of standardized training programs, maintenance of safety practices and operational manuals, investigation of incidents, and the efficient remediation and reclamation of sites. The HSE representative will regularly report to the Board of Directors.

Enterra Energy Trust has made a tremendous transition over the past year, moving from a small Alberta-based producer with a modest medium-weight oil development opportunity, to a moderate-sized Canada- and US-based entity with a diverse and balanced production portfolio and a rich range of exploitation and development programs.

Outlook

FOR 2006

To help us meet the challenge of generating maximum value from these development opportunities throughout 2006 and beyond, we will:

- complete tie-in programs from the 2005/06 winter activities to bring on approximately a net 1,000 boe/day;
- improve the efficiency of our base portfolio by phasing out under-performing and non-core assets and through field lifting cost optimization and enhanced depletion planning;
- execute further development drilling in core areas in Canada and Wyoming;
- fully integrate our new Oklahoma assets and initiate extensive development programs there; and
- continue building our staff to provide the Trust with the technical and financial resources to create the highest long-term value for unitholders.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is Management's Discussion and Analysis ("MD&A") of Enterra Energy Trust ("the Trust") for the year ended December 31, 2005. This MD&A should be read in conjunction with the accompanying audited consolidated financial statements of the Trust for the year ended December 31, 2005. All amounts are stated in Canadian dollars and are prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP") except where otherwise indicated. This MD&A was written as of March 29, 2006.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This MD&A includes forward-looking statements. All statements other than statements of historical facts contained in this MD&A, including statements regarding the Trust's future financial position, business strategy and plans and objectives of management for future operations, are forward-looking statements. The words "believe," "may," "will," "estimate," "continue," "anticipate," "intend," "should," "plan," "expect" and similar expressions, as they relate to the

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

Other sections of this MD&A may include additional factors that could adversely affect the Trust's business and financial performance. Moreover, the Trust operates in a very competitive and rapidly changing environment. New risk factors emerge from time to time and it is not possible for management to predict all risk factors, nor can the Trust assess the impact of all factors on the Trust's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

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

SPECIAL NOTE REGARDING NON-GAAP TERMS

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

OVERVIEW AND STRATEGY

The Trust's strategy is to improve the overall quality of assets that underwrite the unitholder's value and future distributions. The acquisition of High Point Resources Inc. in August was the first significant step along this path. Rigorous processes have been and are being established to ensure strict cost accountability and regulatory compliance in all aspects of the business. These significant changes are ongoing into 2006, so that the Trust will continuously improve its performance. The Trust now has staff of over 80 employees, establishment of full finance, accounting, tax, technical and operational staff, both in head office, and in the field.

The Trust operates as an oil and natural gas income trust. The Trust pays monthly cash distributions on the 15th day of each month to unitholders of record on the immediately preceding distribution record date. The business strategy is to maintain and enhance oil and natural gas reserves to provide long term sustainable cash distributions to unitholders. The Trust uses a three-pronged strategy to achieve its goals through acquisition of producing properties with extensive potential for additional development upside, the use of strategic farm outs to develop these properties, and the pre-agreed acquisition from the farmee of the production resulting from these farm outs. Acquisitions are financed with cash flow, equity and with debt, the optimal mix being one that provides for the strongest balance sheet, and hence the maximum accretion of value to the unitholder. The Trust's ability to replace and grow quality reserves using these strategies is a key success factor in its business outcomes.

The Trust also looks to improve the efficiency of its portfolio via a focus on higher quality products such as light oil and natural gas, and through the rationalization of assets with higher operating costs.

The Trust completed three acquisitions during the year ended December 31, 2005. On January 26, 2005 the Trust closed an acquisition of Canadian petroleum and natural gas properties for cash consideration of $12.1 million. On June 1, 2005, the acquisition of Rocky Mountain Gas, Inc. ("RMG"), a Wyoming coal bed methane company, was closed for consideration of approximately $24.0 million, including $0.4 million of transaction costs. The consideration consisted of 736,842 exchangeable shares (exchangeable on a one-to-one basis into trust units) valued at $16.7 million, 275,474 trust units valued at $6.3 million and $1.0 million in cash. On August 17, 2005, the acquisition of High Point Resources Inc. ("High Point") closed for consideration of approximately $201.5 million, including $1.3 million of transaction costs. In addition the Trust assumed $75.0 million in debt and $6.1 million in working capital deficiency. The consideration consisted of 7,490,898 trust units valued at $168.5 million and 1,407,177 exchangeable shares (exchangeable on a one-to-one basis into trust units) valued at $31.7 million.

With the acquisitions, and the Trust's oil and natural gas development, the Trust increased its proved reserves 94% to 14,295,000 boe and its proved and probable reserves 102% to 19,032,200 boe. The Trust invested $21.5 million in its development program and on maintaining operations.

During 2005, the Trust entered into an arrangement with Kingsbridge Capital Limited ("Kingsbridge") whereby, at the discretion of the Trust, Kingsbridge has committed to purchase up to US$100 million of trust units over a 24-month period. On November 10, 2005, the Trust filed a US$500 million Base Shelf Prospectus.

OVERALL PERFORMANCE

Our financial results have been positively affected by increased natural gas sales volumes, arising from the three acquisitions completed in 2005, the most significant contributor being the High Point acquisition. With the completion of the High Point acquisition, the Trust exited 2005 with sales volumes of approximately 9,282 boe/day. The Trust realized an average total production of 7,741 boe/day compared to 6,957 boe/day in 2004.

Fueled by the increased production from the acquisitions and higher oil and natural gas prices, the Trust increased cash provided by operating activities by 61% to $68.1 million compared to $42.3 million in 2004. This increase led to an increase in funds from operations of 40% to $70.5 million in 2005 compared to $50.2 million in 2004. Net earnings for the Trust decreased by 93% to $1.0 million in 2005 from $14.0 million in 2004. On a per unit basis, the Trust decreased earnings by 95% to $0.03/unit compared to $0.62/unit in 2004. Net earnings and net earnings per unit have decreased in the current year due to a $13.8 million ceiling test write down and a $9.3 million impairment loss on the goodwill within the Trust's U.S. cost center. In addition, net earnings decreased in the current year due to increased depletion costs associated with the acquisition of High Point in 2005.

A total of $66.2 million was paid to unitholders through distributions in 2005 compared to $40.4 million in 2004.

SUMMARIZED FINANCIAL AND OPERATIONAL DATA
(in thousands except for volumes and per unit amounts)

	Three Months Ended December 31,			Years Ended December 31,		
	2005	2004 (restated)[2]	*Change*	**2005**	2004 (restated)	*Change*
Oil and natural gas revenues	$ **50,248**	$ 33,593	50%	$ **157,743**	$ 108,293	46%
Average sales (boe/day)	**9,883**	7,925	25%	**7,741**	6,957	11%
Exit sales rate (boe/day)	**9,282**	7,258	28%	**9,282**	7,258	28%
Cash provided by operating activities	$ **19,575**	$ 14,192	38%	$ **68,120**	$ 42,345	61%
Funds from operations[1]	$ **19,519**	$ 14,103	38%	$ **70,545**	$ 50,242	40%
Net earnings (loss)	$ **(12,937)**	$ 3,256	(497%)	$ **970**	$ 14,027	(93%)
Net earnings (loss) per trust unit - basic	$ **(0.37)**	$ 0.13	(385%)	$ **0.03**	$ 0.62	(95%)
Weighted average number of trust units outstanding - basic	**35,358**	25,296	40%	**29,534**	22,518	31%
Average price per barrel of oil	$ **56.83**	$ 49.90	14%	$ **58.47**	$ 43.00	36%
Average price per mcf of natural gas	$ **8.82**	$ 6.87	28%	$ **8.40**	$ 6.69	26%
Production expenses per boe	$ **12.26**	$ 10.98	12%	$ **11.55**	$ 9.25	25%

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

(2) Restated for the adoption of EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts". See note 3 of the 2005 notes to consolidated financial statements.

SELECT FINANCIAL INFORMATION *(in thousands except per unit amounts)*	2005	2004 (restated)	2003 (restated)
Total revenue	$ 157,743	$ 108,293	$ 72,097
Net earnings	$ 970	$ 14,027	$ 5,430
Net earnings per trust unit			
Basic	$ 0.03	$ 0.62	$ 0.29
Diluted	$ 0.03	$ 0.62	$ 0.27
Total assets	$ 611,543	$ 221,128	$ 116,705
Total long term liabilities	$ 126,322	$ 39,544	$ 19,513
Cash distributions	$ 69,496	$ 42,361	$ 2,451
Cash distributions per unit	$ 1.90	$ 1.66	$ 0.10

RESULTS OF OPERATIONS

PRODUCTION

The Trust increased its average production by 11% to 7,741 boe/day from 6,957 boe/day in 2004. This increase was mainly due to increased natural gas production from the High Point acquisition. The acquisition provided the Trust with 2,998 boe/day of additional volume at the time of closing.

The Trust's production consisted of 5,453 bbls/day of oil and natural gas liquids ("NGL") and 13,729 mcf/day of natural gas, or a mix of 70% oil and NGL and 30% natural gas. As at December 31, 2005, the Trust had an exit rate of 9,282 boe/day.

PRODUCTION *(in thousands except for volumes and percentages)*	Three Months Ended December 31,			Years Ended December 31,		
	2005	2004 (restated)	*Change*	2005	2004 (restated)	*Change*
Daily Sales Volumes – Average						
Oil & NGL (bbls/day)	5,762	6,766	(15%)	5,453	5,821	(6%)
Natural gas (mcf/day)	24,727	6,954	256%	13,729	6,817	101%
Total (boe/day)	9,883	7,925	25%	7,741	6,957	11%
Daily Sales Volumes - Exit Rate						
Oil & NGL (bbls/day)	5,476	5,905	(7%)	5,476	5,905	(7%)
Natural gas (mcf/day)	22,836	8,118	181%	22,836	8,118	181%
Total (boe/day)	9,282	7,258	28%	9,282	7,258	28%
Sales Volumes mix by product						
Oil & NGL	58%	81%		70%	81%	
Natural gas	42%	19%		30%	19%	
	100%	100%		100%	100%	

For the fourth quarter ended December 2005, the Trust realized an average sales volume of 5,762 bbls/day of oil and NGL and 24,727 mcf/day of gas (2004: 6,766 bbls/day and 6,954 mcf/day respectively).

For 2006, the Trust expects production to increase significantly. The Trust acquired oil and gas producing properties located in Oklahoma ("Oklahoma Assets") in the first quarter of 2006. These assets are forecasted to add approximately 6,300 boe/day of production for the Trust.

COMMODITY PRICING

Prices for both oil and natural gas increased significantly in 2005 compared to 2004. A combination of increasing world demand and one of the worst hurricane seasons North America has experienced pushed prices to their highest levels ever. In addition, during the latter part of 2005, the Trust instituted the internalization of full service product marketing functionality including active movement of heavier crudes to specific market centers to maximize realizations, and establishing gas trunk line shipper status. These latter organizational changes have had a positive impact on company realizations.

West Texas Intermediate ("WTI") is a standard benchmark for the price of oil. WTI is expressed in US dollars per barrel ("bbl"). The Trust reports the price it receives for oil in Canadian dollars per bbl. Alberta Spot prices, represented as AECO hub pricing ("AECO"), is a standard benchmark for the price of natural gas in Western Canada. AECO is expressed in Canadian dollars.

WTI realized an average price of US$56.56/bbl for 2005 compared to US$41.40/bbl in 2004. Alberta AECO was $8.73/mcf for 2005 compared to $6.79/mcf for 2004. The strengthening of the Canadian dollar dampened the upward price movement as oil and gas are benchmarked in US dollars. The average exchange rate decreased to 1.21 in 2005 from 1.30 in 2004.

The Trust utilized a price risk management program to mitigate its exposure to price changes for oil and natural gas. Inclusive of this price risk management program, the Trust realized an average price of $58.11/bbl of oil in 2005 compared to $43.00/bbl in 2004 and $8.40/mcf of natural gas in 2005 compared to $6.69/mcf in 2004.

The Trust has financial collars for 2,000 boe/day of oil production into 2006 the price of which is between US$55.00/bbl and US$80.00/bbl. The Trust has financial floor and collar swaps for 10,000 GJ/day of gas production into 2006 the price of which ranges from Cdn$8.50/GJ to Cdn$14.00/GJ.

PRICING
(in thousands except for volumes and pricing)

	Three Months Ended December 31,			Years Ended December 31,		
	2005	2004 (restated)	*Change*	**2005**	2004 (restated)	*Change*
Pricing Benchmarks						
WTI (US$/bbl)	**$ 60.03**	$ 48.28	24%	**$ 56.56**	$ 41.40	37%
Average exchange rate:						
US$1.00 to $CDN =	**1.17**	1.25	(6%)	**1.21**	1.30	(7%)
WTI (CDN$/bbl)	**$ 70.24**	$ 60.35	16%	**$ 68.44**	$ 53.82	27%
AECO monthly index (CDN$/mcf)	**$ 11.39**	$ 7.09	61%	**$ 8.73**	$ 6.79	29%
Average Prices Received by the Trust						
Oil (CDN per bbl)	**$ 56.83**	$ 49.90	14%	**$ 58.11**	$ 43.00	35%
Natural gas (CDN per mcf)	**$ 8.82**	$ 6.87	28%	**$ 8.40**	$ 6.69	26%
Total (CDN per boe)	**$ 55.26**	$ 47.33	17%	**$ 55.83**	$ 42.53	31%

In Q4 2005 the Trust realized an average price of $56.83/bbl for oil and $8.82/mcf for natural gas compared to $49.90/bbl and $6.87/mcf respectively in 2004.

REVENUES

The increase in revenues was due to the increase in natural gas sales volumes together with the increases in the sales prices of oil and natural gas. The increase in natural gas sales volumes was a direct result of the High Point acquisition, a company whose production was heavily natural gas weighted, for which the operating results have been included in the consolidated balances since August 17, 2005. The increase in sales prices was a result of the current commodity price environment tempered by the stronger Canadian dollar.

REVENUES
(in thousands)

	Three Months Ended December 31,			Years Ended December 31,		
	2005	2004 (restated)	*Change*	**2005**	2004 (restated)	*Change*
Revenues						
Oil and NGL	**$ 30,105**	$ 29,196	3%	**$ 115,645**	$ 91,611	26%
Natural gas	**20,143**	4,397	358%	**42,098**	16,682	152%
Total	**$ 50,248**	$ 33,593	50%	**$ 157,743**	$ 108,293	46%

Revenue in Q4 2005 increased 50% to $50.2 million from $33.6 million in 2004. The increase in this revenue is due to the increased natural gas volumes from the High Point acquisition and the increased commodity prices received in the quarter.

ROYALTIES

Royalties, which include Crown, freehold and overriding royalties, offset by Alberta Royalty Tax Credits ("ARTC"), have increased compared to the prior periods as the result of the increased revenues in 2005. Royalties are based on the volume of production or sales and commodity price, therefore royalties per boe fluctuate in relation to the fluctuation in the prices received by the Trust for the oil and natural gas sales.

ROYALTIES
(in thousands except for percentages and per boe amounts)

	Three Months Ended December 31,			Years Ended December 31,		
	2005	2004 (restated)	*Change*	**2005**	2004 (restated)	*Change*
Royalties	**$ 12,920**	$ 7,958	62%	**$ 36,079**	$ 24,527	47%
As a percentage of revenue	**26%**	24%		**23%**	23%	
Royalties per boe	**$ 14.21**	$ 10.91	30%	**$ 12.77**	$ 9.63	33%

For 2006, the Trust projects royalties to remain relatively constant as a percentage of revenue.

PRODUCTION EXPENSES

The Trust experienced higher operating costs in 2005 compared to 2004. The additions of production due to the acquisition of Rocky Mountain Energy, Rocky Mountain Gas and High Point have increased the Trust's overall lifting expense. The Trust's southeastern Alberta oil producing properties are under extensive water flood and pumping schemes and were subject to higher electricity prices and workover costs in 2005 ($4.4 million) relative to 2004 ($1.7 million). In addition, cost increases in fuel, well servicing day rates, and contractor expense occurred due to competitive nature of the oil and gas industry.

One time costs totaling $0.4 million were incurred at Sylvan Lake field to replace defective pumping rods and at Claire field to refit a water source well. Overall, the 2005 cost increases were partially offset by the low cost production associated with the properties acquired in the High Point acquisition.

PRODUCTION EXPENSES
(in thousands except for percentages and per boe amounts)

	Three Months Ended December 31,			Years Ended December 31,		
	2005	2004 (restated)	*Change*	**2005**	2004 (restated)	*Change*
Production expenses	$ **11,007**	$ 8,007	37%	$ **32,620**	$ 23,492	39%
Production expenses per boe	$ **12.11**	$ 10.98	10%	$ **11.55**	$ 9.25	25%

With the completion of the High Point acquisition, and continued development of the related natural gas properties, overall operating costs per boe are expected to trend downward in 2006. The Oklahoma asset additions are expected to have production costs lower than the existing assets of the Trust.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses increased by 133% to $10.3 million from $4.4 million in 2004. The year over year increase was also impacted by the increased audit and consulting services required to respond to the resignation of senior officers of the Trust in the first quarter of 2005 and the 2004 bonus that was approved by the unitholders in 2005, paid and recorded as an expense in the second quarter of 2005. Additionally, G&A expenses have increased due to computer software purchases and higher costs associated with regulatory compliance in Canada and the U.S. During 2005, the Trust expanded its employee base to reduce the Trust's reliance on the Technical Services Agreement between the Trust and JED Oil Inc. Finally, the Trust discontinued the capitalization of administrative costs.

GENERAL AND ADMINISTRATIVE EXPENSES
(in thousands except for percentages and per boe amounts)

	Three Months Ended December 31,			Years Ended December 31,		
	2005	2004 (restated)	*Change*	**2005**	2004 (restated)	*Change*
G&A expenses	$ **2,990**	$ 1,300	130%	$ **10,331**	$ 4,440	133%
G&A per boe	$ **3.29**	$ 1.78	85%	$ **3.66**	$ 1.75	109%

General and administrative ("G&A") expenses for Q4 2005 increased over the corresponding period in 2004 due to the expansion in operations of the Trust. Additional personnel costs in the form of salaries and consulting fees along with higher legal costs have been incurred in connection with the integration and administration of the High Point assets, regulatory compliance requirements and the filing of the Base Shelf Prospectus.

G&A expenses per boe are expected to decline in 2006 as a result of the additional sales volumes acquired with the High Point acquisition that will be included for the entire year. The Oklahoma Assets will provide additional sales volumes with relatively low associated G&A. The acquisition will increase total G&A, but decrease it on a per boe basis.

INTEREST EXPENSE

Interest expense has increased due to the higher average outstanding loan balances during the period, interest on the bridge credit facility for the High Point acquisition, and the increase in interest rates from the prior periods.

INTEREST EXPENSE (in thousands except for percentages and per boe amounts)						
	Three Months Ended December 31,			Years Ended December 31,		
	2005	2004 (restated)	*Change*	2005	2004 (restated)	*Change*
Bank debt, capital lease, and notes payable at end of period	$ 102,101	$ 47,316	116%	$ 102,101	$ 47,316	116%
Interest expense	$ 2,000	$ 491	307%	$ 4,715	$ 2,222	112%
Interest expense per boe	$ 2.20	$ 0.67	227%	$ 1.67	$ 0.87	92%

Interest expense has increased in Q4 2005 compared to Q4 2004 due to the higher average outstanding loan balances during the period, interest on the bridge credit facility for the High Point acquisition, and the increase in interest rates from the prior periods.

The Trust expects interest expense to increase in 2006 due to the bridge financing of the acquisition of the assets in Oklahoma. This bridge facility is expected to be replaced by a combination of equity and debt.

DEPLETION, DEPRECIATION AND ACCRETION ("DD&A")

DD&A expense increased in both Q4 2005 and the full year 2005 compared to respective periods in 2004, primarily due to the higher cost per boe of the oil and natural gas properties acquired with the east central Alberta, RMG, and High Point acquisitions.

In 2005 a provision of $13.8 million is included within DD&A due to a ceiling test write down in the United States cost center. The provision was required due to the expiration of certain undeveloped lands in RMG, which increased the cost base that the test is calculated on and a reduction of the reserves in the December 31, 2005 reserve report due to the results from the properties during 2005.

DEPLETION, DEPRECIATION AND ACCRETION (in thousands except for percentages and per boe amounts)						
	Three Months Ended December 31,			Years Ended December 31,		
	2005	2004 (restated)	*Change*	2005	2004 (restated)	*Change*
DD&A – excluding write down	$ 27,812	$ 11,794	136%	$ 68,229	$ 35,976	90%
DD&A – excluding write down per boe	$ 30.59	$ 16.18	89%	$ 24.15	$ 14.13	71%
Ceiling test provision	$ 13,844	–		$ 13,844	–	
DD&A	$ 41,656	$ 11,794	253%	$ 82,073	$ 35,976	128%
DD&A per boe	$ 45.82	$ 16.18	183%	$ 29.05	$ 14.13	105%

GOODWILL IMPAIRMENT LOSS

With the ceiling test write down in the United States cost center as noted above, the Trust also realized an impairment loss on the goodwill for the United States reporting unit. A loss of $9.3 million was realized for 2005 due to this impairment.

COMMODITY CONTRACTS

For 2005, the Trust entered into financial floor and collar swap contracts to hedge a portion of the natural gas and oil production. At December 31, 2005 these contracts had a mark-to-market value of $0.4 million. Hedge costs of $0.1 million were incurred on the contracts.

During 2004, the Trust had several commodity hedge contracts that resulted in losses of $1.9 million, $0.3 million and $1.0 million in Q1, Q2 and Q4 respectively.

The Trust has entered into physical delivery contracts to sell certain natural gas volumes at fixed prices. The physical delivery contracts are summarized below:

	Contract Period End	Quantity	Pricing (Cdn/GJ)	Estimated fair value
Natural Gas Contracts	March 31, 2006	8,000 GJ/day	$8.01 to $8.85	$ (1,293)

TAXES

The Trust is subject to tax on its income or loss for each taxation year, computed as though it was a separate individual resident in Canada. The taxation year of the Trust will end on December 31 of each year. Under the Trust Indenture, the Trust is not subject to income taxes if all of its taxable income will be paid or made payable by way of cash distributions to the unitholders.

The corporate subsidiaries of the Trust are subject to tax if the discretionary deductions available are inadequate to reduce taxable income to zero. These discretionary deductions are often referred to as tax pools.

	Three Months Ended December 31,		Years Ended December 31,	
	2005	2004 (restated)	**2005**	2004 (restated)
Current tax expense	**$ 354**	$ 170	**$ 1,456**	$ 260
Future income tax (recovery)	**(15,325)**	(396)	**(18,689)**	(280)
Total tax (recovery)	$ (14,971)	$ (226)	$ (17,233)	$ (20)

Current tax expense relates primarily to capital tax, which is based on debt and equity levels at the end of the year. The increase in capital tax expense in 2005 is primarily due to a higher taxable capital base from the acquisition of High Point.

Future income tax recovery of $18.7 million arises from several factors. One factor is the decreased accounting basis of the property, plant and equipment stemming from the impairment of US cost center of $13.8 million, giving a future income tax recovery of $4.7 million. The second factor arises from an adjustment in the tax rate applied to the temporary differences in the fourth quarter of 2005, giving rise to approximately $1.2 million in the future income tax recovery. The remainder relates to the excess of depletion taken over the use of tax pools in the fourth quarter, a result from the acquisition of High Point.

The corporate acquisitions in 2005 resulted in an increase of $96.9 million in the future income tax liability. This represents the difference between the tax basis and fair values assigned to the acquired assets.

NON-CONTROLLING INTEREST

The Trust's exchangeable shares are classified as non-controlling interest on the consolidated balance sheets. Income after tax attributable to these exchangeable shares is deducted from net earnings of the Trust on the consolidated statements of earnings.

In 2005, 953,129 exchangeable shares were exchanged into trust units (2004 – 1,784,264).

NON-GAAP FINANCIAL MEASURES

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

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

FUNDS FROM OPERATIONS

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

	Three Months Ended December 31,		Years Ended December 31,	
	2005	2004 (restated)	**2005**	2004 (restated)
Cash provided by operating activities	**$ 20,575**	$ 14,192	**$ 68,120**	$ 42,345
Changes in non-cash working capital items	**(1,056)**	(89)	**2,425**	7,897
Funds from operations	**$ 19,519**	$ 14,103	**$ 70,545**	$ 50,242

QUARTERLY FINANCIAL INFORMATION

QUARTERLY FINANCIAL INFORMATION
(in thousands except for per unit amounts)

	2005				2004			
	Q1 (restated)	Q2	Q3	**Q4**	Q1 (restated)	Q2 (restated)	Q3 (restated)	Q4 (restated)
Revenues	$ 30,050	$ 29,807	$ 47,638	**$ 50,248**	$ 21,648	$ 27,585	$ 25,467	$ 33,593
Earnings (loss) before taxes and non-controlling interest	$ 3,757	$ 947	$ 7,530	**$(28,526)**	$ 201	$ 5,798	$ 5,313	$ 3,103
Net earnings	$ 4,252	$ 2,567	$ 7,088	**$(12,937)**	$ 2,396	$ 4,455	$ 3,920	$ 3,256
Net earnings (loss) per trust unit								
Basic	$ 0.16	$ 0.10	$ 0.23	**$ (0.37)**	$ 0.12	$ 0.21	$ 0.17	$ 0.13
Diluted	$ 0.16	$ 0.10	$ 0.23	**$ (0.37)**	$ 0.12	$ 0.21	$ 0.17	$ 0.13
Distributions (US$)	$ 0.43	$ 0.46	$ 0.49	**$ 0.52**	$ 0.31	$ 0.34	$ 0.37	$ 0.40

The quarterly information reflects a general trend to increasing revenues reflecting the overall growth of the Trust and the rising price of the oil and natural gas sold by the Trust. This growth has provided cash flow for the Trust to increase distributions to its unitholders.

CASH DISTRIBUTIONS PAID TO UNITHOLDERS

The Trust pays monthly cash distributions to its unitholders. Cash distributions are paid on the 15th of the following month (e.g. the December distribution was paid on January 15). The monthly cash distributions per trust unit since the inception of the Trust are as follows:

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

	Three Months Ended December 31,			Years Ended December 31,		
	2005	2004 (restated)	*Change*	2005	2004 (restated)	*Change*
Cash distributions to unitholders	$ 21,067	$ 12,076	74%	$ 66,195	$ 40,414	64%
Funds from operations	$ 19,519	$ 14,103	38%	$ 70,545	$ 50,242	40%
Cash distributions as a percentage of funds from operations	108%	86%		94%	80%	

In the fourth quarter, funds from operations were reduced due to several large adjustments. There was a reclassification of certain workovers, which resulted in an expense of $2.2 million of previously capitalized items. The fourth quarter also recorded additional freehold and gross overriding royalties of $0.8 million pertaining to wells acquired through the 2004 Rocky Mountain Energy Corp. The capital tax accrual for 2005 was increased by $0.8 million as a result of finalizing the balance sheet values on an unconsolidated basis and including the High Point organizations in the calculation.

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

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

For Canadian tax purposes, cash distributions comprise of a return of capital portion, which is tax deferred, and return on capital portion, which is taxable income. The return of capital portion reduces the cost base of the trust units held. The cost base is required in the calculation of a capital gain or loss upon the disposition of the trust units. For 2005, the cash distributions declared for 2005 is approximately at 51% return on capital (taxable) and 49% return of capital (tax deferred). For tax information for non-resident unitholders, please visit our website at www.enterraenergy.com.

CAPITAL EXPENDITURES

The Trust does not have material commitments for capital expenditures. The business strategy is to have other companies spend the capital to develop our properties in exchange for the Trust receiving a 30% working interest in the developed properties at no additional cost. We also retain a right of first refusal to purchase the remaining 70% working interest. Any such purchases are financed with cash flow, issuing new trust units or incurring new debt.

The Trust closed three acquisitions in 2005. On January 26, 2005 the Trust closed an acquisition of petroleum and natural gas properties for cash consideration of $12.1 million. On June 1, 2005, the acquisition of Rocky Mountain Gas, Inc. closed for consideration of approximately $24.0 million, including $0.4 million of transaction costs. The consideration consisted of 736,842 exchangeable shares (exchangeable on a one-to-one basis into trust units) valued at $16.7 million, 275,474 trust units valued at $6.3 million and $1.0 million in cash. The acquisition of High Point was closed on August 17, 2005, for consideration of approximately $201.5 million, including $1.3 million of transaction costs. In addition the Trust assumed $75.0 million in debt and $6.1 million working capital deficiency. The consideration consisted of 7,490,898 trust units valued at $168.5 million and 1,407,177 exchangeable shares (exchangeable on a one-to-one basis into trust units) valued at $31.7 million.

The following table represents the Trust's capital expenditures that were paid for with cash. The source of this cash was through private placements of trust units and from working capital. The table excludes capital expenditures, such as the portion of the RMG and High Point acquisitions, that were paid for with non-cash consideration such as trust units and exchangeable shares.

CAPITAL EXPENDITURES PAID WITH CASH
(in thousands except for percentages)

	Three Months Ended December 31,			Years Ended December 31,		
	2005	2004 (restated)	*Change*	**2005**	2004 (restated)	*Change*
Capital expenditures net of disposals	$ **9,181**	$ 615	1,392%	$ **33,617**	$ 30,409	11%

Capital additions for the year ended December 31, 2005 were $424.2 million (2004 - $65.2 million). In addition to the three acquisitions and the capital expenditures paid with cash, $1.9 million of net asset retirement obligations ("ARO") were charged to property, plant and equipment.

	Years Ended December 31,	
	2005	2004 (restated)
Property acquisitions	$ **393,784**	$ 30,385
Proceeds on disposal of properties	**–**	(1,177)
Drilling and completions	**10,637**	11,001
Facilities and equipment	**14,630**	24,475
Other	**628**	555
Other ARO additions	**1,901**	1,270
Net capital additions	$ **421,580**	$ 66,509

For 2006, the Trust plans to continue its capital additions through a combination of acquisitions and development activities. The Trust will continue to farm out its undeveloped land to keep capital expenditures to a minimum while still increasing its production base. This trend of lower drilling and completions and facilities and equipment costs is expected to continue through 2006. The Trust also closed the acquisition of roughly 6,300 boe/day of assets in Oklahoma during the first quarter of 2006.

RESERVES AND PRESENT VALUE SUMMARY

The Trust complies with the National Instrument 51-101, issued by the Canadian Securities Administrators, in all its reserves related disclosures.

Proved reserves (P90) - For reported reserves this means there must be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves.

Proved plus Probable (P50) - For reported reserves there must be at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the proved plus probable reserves. The probable reserves will no longer be risked by 50 percent as they are implicitly risked due to the nature of the new definition of reserves.

The purpose of NI 51-101 is to enhance the quality, consistency, timeliness and comparability of oil and gas activities by reporting issuers and elevate reserves reporting to a higher level of accountability.

Reserve volumes and values at December 31, 2005 are based on the Trust's interest in its total proved and probable reserves prior to royalties as defined in NI 51-101. Reserve volumes and values for years prior to 2003 are based on "established" (proved plus 50% probable) reserves prior to deduction of royalties. Under those definitions, probable reserves were discounted by an arbitrary risk factor of 50% in reporting established reserves. Under NI 51-101 reserves definitions, estimates are prepared such that the full proved and probable reserves are estimated to be recoverable (proved plus probable reserves are effectively a "most likely case"). As such, the probable reserves reported are already "risked".

The Trust has its reserves evaluated by independent engineers each year. McDaniel and Associates Consultants Ltd. ("McDaniel") independently evaluated the 2005 Canadian asset reserves of the Trust and Sproule Associates Inc. ("Sproule") independently evaluated the Trust's affiliate Rocky Mountain Gas 2005 reserves as at December 31, 2005.

RESERVE CONTINUITY
Oil and Gas (mboe)

	Proved	Probable	Total
December 31, 2003	6,142.9	2,291.9	8,434.8
Discoveries and extensions	185.7	81.3	267.0
Purchases	3,544.2	1,362.0	4,906.2
Dispositions	(29.0)	(2.0)	(31.0)
Production	(2,550.5)	–	(2,550.5)
Revision of prior estimates	92.2	(1,709.3)	(1,617.1)
December 31, 2004	7,385.5	2,023.9	9,409.4
Discoveries and extensions	47.5	13.8	61.3
Purchases (including East Central Properties acquisition)	9,784.1	5,020.1	14,804.2
Dispositions	–	–	–
Production	(2,825.3)	–	(2,825.3)
Revision of prior estimates[1]	(96.8)	(2,320.6)	(2,417.4)
December 31, 2005	14,294.9	4,737.2	19,032.1

[1]Revision of prior estimates includes revision of 1,630 mboe related to 2005 purchased assets in the U.S. based upon performance versus initial expectations

Proved plus probable reserves increased 102% from the end of 2004 to the end of 2005 due to ongoing development and three acquisitions. Proved reserves increased 94% from 7,385.5 mboe to 14,294.9 mboe and probable reserves increased 134% from 2,023.9 mboe to 4,737.2 mboe. Total proved reserves represent 75% of total reserves versus 78% in 2004.

Finding costs incurred over the last three years are highlighted below, along with the recycle ratios for each year. The recycle ratio is a critical measure of any success in the oil and gas industry. It compares the netbacks with the finding costs. Basically, a recycle ratio of one is a "break even point", indicating that the enterprise earns the same amount when selling its production as it pays when finding new production.

FINDING COSTS AND RECYCLE RATIO
(in $/boe, except for capital expenditures which are in thousands)

	2005	2004	2003	3-year Average
Capital expenditures	$ 421,580	$ 66,509	$ 51,577	$ 179,889
Reserves				
Proved reserves added in the year (in mboe)	9,831.6	3,729.9	2,940.1	5,500.5
Probable reserves added in the year (in mboe)	5,033.9	1,443.3	892.5	2,456.6
Established reserves added in the year (in mboe)(1)	14,865.5	5,173.2	3,832.6	7,957.1
Finding costs				
Proved reserves ($/boe)	42.88	17.83	17.54	32.70
Established reserves ($/boe)	28.36	12.86	13.46	22.61
Recycle ratio (netbacks divided by finding costs)				
Corporate netbacks ($/boe)(2)	25.98	21.06	19.93	22.32
Corporate recycle ratio (based on established finding costs)	0.92	1.64	1.48	0.99
Operating netbacks ($/boe)(3)	31.31	23.67	22.73	25.90
Operating recycle ratio (based on established reserves)	1.10	1.84	1.69	1.15

(1) Established reserves are proved plus probable reserves

(2) Corporate netbacks are production revenue less royalties, operating costs, G&A and interest expense

(3) Operating netbacks are production revenue less royalties and operating costs

Finding costs and recycle ratios are non-GAAP financial measures that may not be comparable to similar measures presented by other entities.

Enterra's high finding costs in 2005 are largely caused by the three acquisitions that were made. The very competitive acquisition market in 2005 resulted in increased acquisition costs versus previous years. The reserve additions from development opportunities were more than offset by negative revisions due to earlier shutting in of several pools in Rocky Mountain Gas due to increased nitrogen content in the gas making it unmarketable.

An additional factor impacting finding costs in 2005 is the higher than normal expenditures on capital projects to maintain existing production. Examples of these projects are the consolidation of existing production facilities to lower operating costs and the replacement of existing failed pipelines.

ENTERRA ENERGY TRUST – ESTIMATED PETROLEUM AND NATURAL GAS RESERVES AND NET PRESENT VALUE (December 31, 2005) (NPV in thousands)						Net Present Value BeforeIncome Tax (M$)		
	Light/ Medium Oil (MBBL)	Heavy Oil (MBBL)	Natural Gas (MMCF)	NGL's (MBBL)	Total (MBOE)	0%	10%	15%
Canadian Assets								
McDaniel report								
Proved Producing	3,623.6	1,292.4	33,986.3	1,121.1	11,701.6	321.7	249.4	226.9
Proved Non-Producing	4.2	–	5,877.4	143.4	1,127.1	32.6	27.8	25.9
Proved Undeveloped	53.4	–	4,634.3	141.8	967.5	32.2	23.9	21.3
Total Proved	3,681.2	1,292.4	44,498.0	1,406.3	13,796.2	386.5	301.1	274.1
Total Probable	1,148.1	421.2	15,610.1	523.5	4,694.5	139.2	76.8	62.7
Total Proved & Probable	4,829.3	1,713.6	60,108.1	1,929.8	18,490.7	525.7	377.9	336.8
United States Assets								
Sproule report								
Proved Producing	–	–	2,993.0	–	498.7	5.9	5.2	4.9
Proved Non-Producing	–	–	–	–	–	–	–	–
Proved Undeveloped	–	–	–	–	–	–	–	–
Total Proved	–	–	2,993.0	–	498.7	5.9	5.2	4.9
Total Probable	–	–	256.0	–	42.7	0.3	0.2	0.1
Total Proved & Probable	–	–	3,249.0	–	541.4	6.2	5.4	5.0
Consolidated Assets								
Proved Producing	3,623.6	1,292.4	36,979.3	1,121.1	12,200.3	327.6	254.6	231.8
Proved Non-Producing	4.2	–	5,877.4	143.4	1,127.1	32.6	27.8	25.9
Proved Undeveloped	53.4	–	4,634.3	141.8	967.5	32.2	23.9	21.3
Total Proved	3,681.2	1,292.4	47,491.0	1,406.3	14,294.9	392.4	306.3	279.0
Total Probable	1,148.1	421.2	15,866.1	523.5	4,737.2	139.5	77.0	62.8
Total Proved & Probable	4,829.3	1,713.6	63,357.1	1,929.8	19,032.1	531.9	383.3	341.8

(1) The Sproule report was converted to Canadian dollars by the Trust using and exchange rate of US$0.85 per Canadian dollar.

LIQUIDITY & CAPITAL RESOURCES

The Trust's business strategy is to have other companies spend the capital to develop properties in exchange for the Trust receiving a 30% working interest in the developed properties at no additional cost. The Trust also retains a right of first refusal to purchase the remaining 70% working interest. Any such purchases will be financed by issuing new equity and/or with debt. The Trust does not have material commitments for capital expenditures.

In March 2006, the Trust closed a $110.0 million senior secured bridge facility. This non-revolving credit facility was be used to payout the existing $100.0 million credit facilities of the Trust. The facility bears interest at 2.5% above bank prime lending rates and matures on December 31, 2006. The facility is secured by a first charge over all Canadian assets of the Trust and a second charge over all US assets.

At December 31, 2005, bank indebtedness represented the outstanding balance under two revolving lines of credit that had a total capacity of $100.0 million. These credit facilities replaced the Trust's previous $41.0 million credit facilities. Drawings on the revolving facilities bear interest at 0.25% above the bank's prime lending rate or bankers' acceptance rates plus margins which were initially set at 135 basis points and are be subject to adjustment up or down prospectively, on a three-month basis as determined by the Trust's consolidated debt to cash flow ratio. Security is provided by a first charge over all of the Trust's assets. The amounts available under these new credit facilities are subject to a semi-annual borrowing base determination.

A bridge credit facility was put in place on August 17, 2005 to facilitate the acquisition of High Point. The bridge credit facility was a reducing non-revolving secured loan with a principal amount of $75.0 million. Security was provided by a first charge on all of the High Point assets that were acquired. The loan bore interest at bank prime rate plus 1% and was repayable from the proceeds of any debt or equity financing or proceeds from the disposal of assets. The loan was repaid in full on November 28, 2005 upon the drawing on the Trust's above noted credit facilities.

On April 22, 2005, the Trust entered into an arrangement with Kingsbridge Capital Limited whereby Kingsbridge has committed to purchase US$100.0 million of trust units. The Trust is not obligated to access any of the capital available under this commitment yet has an option to draw on this commitment through installments for a period of 24 months or until the US$100.0 million is fully drawn. In conjunction with the agreement, Kingsbridge was granted 301,000 warrants to purchase trust units at initially US$25.77 per trust unit.

On November 9, 2005, the Trust filed a US$500.0 million Base Shelf Prospectus and corresponding US Registration Statement. This filing enables the Trust to access the Kingsbridge equity arrangement. The Trust issued 689,079 units for $15.8 million under the Kingsbridge arrangement.

On December 20, 2005 the Trust filed a Prospectus Supplement for the issuance of up to 950,000 trust units at US $16.00 per unit. Under the prospectus, the Trust issued 882,500 units at USD $16.00 per unit under this supplement.

(in thousands)

	Years Ended December 31,	
	2005	2004
Working capital (deficiency)	$ (112,397)	$ (42,354)
Working capital (deficiency) excluding bank debt	$ (16,947)	$ 1,576

The working capital deficiency mainly relates to the requirement of GAAP that the Trust's bank indebtedness and bridge credit facility are classified as current liabilities even though there is no expectation that the revolving lines of credit will be called by the bank.

The Trust does not expect to repay the two bridge facilities from internally generated cash and will need to seek additional financing through the issuance of debt or equity.

The Trust's credit facilities require the Trust to comply with certain financial covenants. Under the arrangements, the lenders can restrict the distributions of the Trust if the Trust is in default. In 2006, the Trust's US$200 million credit facility restricts the Trust's ability to distribute cash flow from the U.S. cost center to US$1.5 million per month.

The Trust expects to increase its cash provided by operating activities and its funds from operations in 2006. The continued benefit of the cash flow from the High Point acquisition combined with the acquisition of the Oklahoma assets is expected to provide strong cash flows for the Trust to fund its working capital, capital expenditures and distributions for 2006.

CONTRACTUAL OBLIGATIONS

The Trust has two ongoing commitments over the next five years, one related to the capital lease and the other related to the rental payments for our office space. These commitments are outlined below:

PAYMENTS DUE BY PERIOD (IN 000'S)					
Contractual Obligations	*Total*	*Less than 1 year*	*1-3 years*	*3-5 years*	*More than 5 years*
Short-Term Debt Obligations	$ 99,521	$ 99,521	$ –	$ –	$ –
Interest on above debt [(1)]	5,011	5,011	–	–	–
Long-Term Debt Obligations	–	–	–	–	–
Capital (Finance) Lease Obligations	2,864	1,065	1,799	–	–
Operating Lease Obligations	5,654	1,160	2,140	2,257	97
Purchase Obligations					
Other Long-Term Liabilities Reflected on the Registrant's Balance Sheet under Canadian GAAP	24,323	–	–	–	24,323
Total	$ 137,373	$ 106,757	$ 3,939	$ 2,257	$ 24,420

[(1)] *using the December 31, 2005 loan balance and its interest rate of 5.25%*

The Trust has indemnified all of the directors and officers of the Trust and all the officers, directors, shareholders, employees and agents of JED Oil Inc. There is no pending litigation or proceeding involving any director or officer of the Trust for which a claim is being sought, nor is the Trust aware of any threatened litigation that may result in claims.

SUBSEQUENT EVENTS AND PROPOSED TRANSACTIONS

During the first quarter of 2006, the Trust acquired roughly 5,000 boe/day of producing oil and gas assets located in Oklahoma. In the second quarter of 2006, the Trust expects to complete a final closing for additional working interests in the properties representing roughly 1,300 boe/day. The assets consist of approximately 80% natural gas and 20% light oil and include over 53,000 net acres of land of which over 25,000 net acres are undeveloped. The current operating staff of the assets is being retained by the Trust.

The purchase price of US$221.0 million was paid for through the issuance of 5,178,792 units of the Trust valued at USD $91.7 million, cash of USD $102.3 million and USD $27.0 million of assumed debts. Certain post closing purchase price adjustment provisions remain in place, based on production rates achieved from the assets through September 19, 2006. The purchase prices on the final closing of the additional working interests will be paid with a combination of units and cash.

The Trust is in the process of entering into a farmout agreement with Petroflow Energy Inc. ("Petroflow"), an oil and gas development company, to fund 100% of the drilling and completion costs on the undeveloped lands to maximize their production potential. The Chief Executive Officer of Enterra Energy Company as administrator of the Trust owns, directly and indirectly, approximately 20% of the outstanding shares of Petroflow.

On January 18, 2006, the Trust entered into an arrangement with a bank for a $50.0 million USD bridge credit facility. This credit facility was used to secure the acquisition of the Oklahoma assets. The facility was a reducing non-revolving loan secured by a first charge over the notes from the sellers of the Oklahoma assets, which were secured by the Oklahoma assets. The loan bore interest at U.S. dollar commercial loan rate + 0.5% and was repaid on March 22, 2006.

In March 2006 the Trust closed a USD $200.0 million senior secured bridge credit facility to fund the acquisition of the Oklahoma assets, repay the USD $50.0 million bridge credit facility noted above and provide additional working capital to the Trust. This non-revolving facility bears interest at 4.5% above London Interbank Offering Rate and matures September 20, 2006 with a one-time option to extend the facility for an additional three-month period. The facility is secured by a first charge over all US assets of the Trust and a second charge over all Canadian assets. As a fee for the facility, the Trust issued 110,000 units to Fortress Credit Corp. The terms of the agreement restrict the Trust's ability to distribute cash flow from the U.S. cost center to USD $1.5 million per month.

In 2006, the Trust closed a $110.0 million senior secured bridge facility. This reducing non-revolving credit facility was be used to payout the existing $100.0 million credit facilities of the Trust. The facility bears interest at 2.5% above bank prime lending rates and matures on December 31, 2006. The facility is reduced to $100 million on June 30, 2006. The facility is secured by a first charge over all Canadian assets of the Trust and a second charge over all US assets.

The Trust does not expect to repay the two bridge facilities from internally generated cash and will need to seek additional financing through the issuance of debt or equity.

RELATIONSHIP WITH JED OIL INC. ("JED")

Under a Technical Services Agreement between the Trust and JED, JED provided certain staff to the Trust while the Trust provided offices and other administrative services to JED. During 2005, JED employees were considered consultants to the Trust and as such, JED's employees were eligible to participate in benefit plans of the Trust. The Chairman of JED is also the Chairman of the Trust.

Under the Technical Services Agreement between the Trust and JED, costs of management, development, exploitation, operations and general and administrative activities were allocated based on relative production and capital expenditures, or as otherwise mutually agreed. For the year ended December 31, 2005, total general and administrative expenses charged by JED to the Trust on a cost recovery basis were approximately $3.9 million and field operating expenses charged by JED to the Trust on a cost recovery basis were approximately $3.0 million.

Effective January 1, 2006 the Technical Services Agreement between the Trust and JED was terminated. The current Chairman of the Trust has resigned effective March 31, 2006 and remains as Chairman of JED.

JED had loaned $8.0 million to the Trust secured by a promissory note. The note had no stated terms of repayment and an initial interest rate of bank prime rate plus 0.4%. Effective August 1, 2005 interest charged on the note increased to 10%. For the year ended December 31, 2005, $0.4 million (2004 - $0 million) of interest was charged on the loaned funds. The promissory note, plus interest charged to January 31, 2006 was repaid in full February 1, 2006.

The balance due to JED at December 31, 2005 was $15.2 million (December 31, 2004 - $4.5 million) consisting of $8.0 million of notes payable and $7.2 million of other transactions.

RELATED PARTY TRANSACTIONS

During 2005 the Trust paid $0.4 million to Macon Resources Ltd., a company 100% owned by the Chief Executive Officer of EEC, for management services provided by the Chief Executive Officer and the Chief Financial Officer. During 2005 the Trust issued 400,000 trust unit options to Macon at $23.96 per option. The options have a 5-year life and vest over a 3-year period.

There were no related party transactions in 2004.

OFF BALANCE SHEET ARRANGEMENTS

There were no off balance sheet arrangements in 2005 or 2004 other than the operating leases discussed elsewhere in the MD&A.

TRUST UNIT INFORMATION

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

OUTSTANDING UNIT DATA *(units/shares)*			
As at	March 27, 2006	December 31, 2005	December 31, 2004
Trust units	43,054,024	36,504,416	25,426,800
Exchangeable shares			
EEC exchangeable shares	336,946	348,146	410,770
RMAC Series A exchangeable shares	–	–	142,444
RMG exchangeable shares	736,842	736,842	–
RMAC Series B exchangeable shares	93,905	659,116	–
Trust unit options	1,451,405	1,431,405	950,000
Warrants	301,000	301,000	–

The exchangeable shares of the subsidiary corporations are not listed for trading on an exchange and are treated as a minority interest under GAAP. The exchangeable shares are convertible into trust units based on their respective exchange ratios.

SENSITIVITIES

The Trust is exposed to the normal risks inherent within the oil and gas sector, including commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. The Trust manages its operations in a manner intended to minimize exposure, as described in note 14 to the consolidated financial statements.

Credit Risk

Credit risk is the risk of loss resulting from non-performance of contractual obligations by a customer or joint venture partner. A substantial portion of the Trust's accounts receivable are with customers in the energy industry and are subject to normal industry credit risk. The Trust assesses the financial strength of its customers and joint venture partners through regular credit reviews in order to minimize the risk of non-payment.

Foreign Exchange Risk

The Trust is exposed to market risk from changes in the exchange rate between U.S. and Canadian dollars. The price we receive for oil and natural gas production is based on a benchmark expressed in U.S. dollars, which is the standard for the oil and natural gas industry worldwide. Monthly distributions are paidon a value expressed in U.S. dollars. However, operating expenses, drilling expenses and general overhead expenses in Canadian dollars. Changes to the exchange rate between U.S. and Canadian dollars can adversely affect the Trust. When the value of the U.S. dollar increases, the Trust receives higher revenue and when the value of the U.S. dollar declines, the Trust receives lower revenue on the same amount of production sold at the same prices. A change of $0.01 in the U.S. to CDN dollar would impact the Trust's earnings by approximately $1.9 million and our cash provided by operating activities by $1.2 million.

Commodity Price Risk

The Trust's financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond the Trust's control. Factors influencing oil and natural gas prices include the level of global demand for crude oil, the foreign supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect the Trust's financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that the Trust can produce economically. Any reduction in the Trust's oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse affect on the Trust's ability to obtain capital for our development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on the Trust's financial condition, results of operations and capital resources. If the WTI oil price were to change by US$1.00 per bbl, the impact on earnings would be approximately $1.8 million and the impact on cash flow would be approximately $2.9 million. If natural gas prices were to change by US$0.50 per mcf, the impact on earnings would be approximately $1.4 million and the impact on cash provided by operating activities would be approximately $2.3 million.

The Trust uses financial derivatives and physical sales contracts to mitigate a portion of oil and natural gas price risk. While the use of these derivative arrangements limits the downside risk of price declines, such use may also limit any benefits that may be derived from price increases.

Interest Rate Risk

Interest rate risk exists principally with respect to indebtedness that bears interest at floating rates. At December 31, 2005, the Trust had $95.5 million of indebtedness bearing interest at floating rates. If interest rate were to change by one full percentage point, the net impact on earnings would be approximately $0.6 million and the net impact on our cash provided by operating activities would be approximately $1.0 million.

Summarized below are the Trust's sensitivities to various risks, based on its 2005 operations:

Sensitivity	Estimated 2006 Impact On: ('000s) Net Earnings	Cash Flow
Crude oil – US$1.00/bbl change in WTI	$ 1,822	$ 2,921
Natural gas – US$0.50/mcf change	$ 1,447	$ 2,320
Foreign exchange - $0.01 change in U.S. to Cdn dollar	$ 1,888	$ 1,178
Interest rate – 1% change	$ 595	$ 955

MANAGEMENT'S EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

As at the financial year ended December 31, 2005, an evaluation was carried out under the supervision of and with the participation of the Trust's management, including the CEO and CFO, of the effectiveness of the Trust's disclosure controls and procedures. Based on that evaluation, the CEO and the CFO concluded that the design and operation of these disclosure controls and procedures were effective as at December 31, 2005 to provide reasonable assurance that material information relating to the Trust would be made known to them by others within the Trust.

CRITICAL ACCOUNTING ESTIMATES

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

a) estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;

b) estimated capital expenditures on projects that are in progress;

c) estimated depletion, depreciation and accretion that are based on estimates of oil and gas reserves which the Trust expects to recover in the future;

d) estimated value of asset retirement obligations that are dependent upon estimates of future costs and timing of expenditures; and

e) estimated future recoverable value of property, plant and equipment and goodwill.

CHANGE IN ACCOUNTING POLICY

On January 19, 2005, the CICA issued EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" that states that equity interests held by third parties in subsidiaries of an income trust should be reflected as either non-controlling interest or debt in the consolidated balance sheet unless they meet certain criteria. EIC-151 requires that the shares be nontransferable to be classified as equity. The Trust's exchangeable shares are transferable and, in accordance with EIC-151, have been reclassified to non-controlling interest on the consolidated balance sheets.

Since the exchangeable shares of the Trust were not initially recorded at fair value, subsequent exchanges for trust units are measured at the fair value of the trust units issued. The excess amounts are allocated to property, plant and equipment and to goodwill. In addition, a portion of consolidated earnings before non-controlling interest is reflected as a reduction to such earnings in the Trust's consolidated statements of earnings and accumulated earnings. Prior periods have been retroactively restated as required by the new accounting standard.

The following tables illustrate the impact of the new accounting policy on the consolidated balance sheet as at December 31, 2004 presented for comparative purposes:

December 31, 2004	As reported	Change upon adoption of EIC-151	As restated
Property, plant and equipment	$ 146,910	$ 1,548	$ 148,458
Goodwill	29,991	19,279	49,270
Future income tax liability	21,526	602	22,128
Non-controlling interest	–	3,349	3,349
Unitholders' capital	111,653	20,554	132,207
Exchangeable shares	3,273	(3,273)	–
Accumulated earnings	27,903	(405)	27,498

The following table illustrates the impact of the new accounting policy on 2004 net earnings and net earnings per trust unit:

	Q1	Q2	Q3	Q4	2004
Net earnings before change in accounting policy	$ 2,562	$ 4,647	$ 4,138	$ 3,417	$ 14,764
Increase in depletion, net of taxes	(63)	(94)	(83)	(89)	(329)
Non-controlling interest	(103)	(98)	(134)	(73)	(408)
Net earnings after change in accounting policy	$ 2,396	$ 4,455	$ 3,921	$ 3,256	$ 14,027
Net earnings per trust unit, as reported					
Basic and diluted	$ 0.12	$ 0.21	$ 0.17	$ 0.13	$ 0.63
Net earnings per trust unit, as restated					
Basic and diluted	$ 0.12	$ 0.21	$ 0.17	$ 0.12	$ 0.62

ADDITIONAL INFORMATION

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

MANAGEMENT'S REPORT TO THE UNITHOLDERS

Management is responsible for the preparation of the financial statements. The financial statements have been prepared in accordance with Canadian generally accepted accounting principles.

Management is responsible for maintaining a system of internal controls that provide reasonable assurance that assets are safeguarded and that relevant and reliable financial information is produced in a timely manner. The Audit Committee of the Board of Directors meets periodically with management and the auditors to satisfy itself that management's responsibilities are properly discharged, to review the financial statements and to recommend approval of the financial statements to the Board.

External auditors, appointed by the unitholders, have examined the financial statements. The Audit Committee of the Board of Directors has reviewed the financial statements with management and the external auditors. The Board of Directors has approved the financial statements on the recommendation of the Audit Committee.

E. Keith Conrad
PRESIDENT & CEO

Calgary, Canada

MARCH 29, 2006

AUDITORS' REPORT TO THE UNITHOLDERS

We have audited the consolidated balance sheets of Enterra Energy Trust as at December 31, 2005 and 2004 and the consolidated statements of earnings and accumulated earnings and cash flow for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2005 and 2004 and the results of its operations and its cash flow for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada
March 29, 2006

FINANCIAL STATEMENTS

COMMENTS BY AUDITOR FOR US READERS ON CANADA-US REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principle that has a material effect on the comparability of the Trust's financial statements, such as the changes described in note 3 to the Trust's consolidated financial statements as at and for the years ended December 31, 2005 and 2004. Our report to the unitholders dated March 29, 2006, is expressed in accordance with Canadian reporting standards which do not required a reference to such changes in accounting principles in the auditors report when the changes are properly accounted for and adequately disclosed in the financial statements.

KPMG LLP

Chartered Accountants
Calgary, Canada
March 29, 2006

CONSOLIDATED BALANCE SHEETS

(Thousands of Canadian dollars)

	2005	2004
Assets		(restated note 3)
Current assets		
Cash	$ 11,943	$ 4,779
Accounts receivable	35,303	15,613
Financial derivatives (note 15)	415	–
Prepaid expenses, deposits and other	3,052	518
	50,713	20,910
Property, plant and equipment (note 6)	489,074	148,458
Deposit on acquisition (note 4)	–	2,400
Deferred financing charges	1,210	90
Goodwill (note 7)	70,546	49,270
	$ 611,543	$ 221,128
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 36,348	$ 8,570
Due to JED Oil Inc. (note 1)	15,151	4,493
Distribution payable to unitholders	7,699	4,398
Income taxes payable	2,066	1,068
Bank indebtedness (note 9)	95,450	43,930
Note payable (note 10)	4,071	–
Marketing contracts	1,447	–
Current portion of capital lease (note 11)	878	805
	163,110	63,264
Asset retirement obligations (note 8)	24,323	14,836
Future income tax liability (note 14)	100,297	22,128
Capital lease (note 11)	1,702	2,580
	289,432	102,808
Non-controlling interest (note 12)	32,402	3,349
Unitholders' Equity (note 13)		
Unitholders' capital	373,761	132,207
Warrants	1,215	–
Contributed surplus	573	78
Accumulated earnings	28,468	27,498
Accumulated distributions	(114,308)	(44,812)
	289,709	114,971
Subsequent events (note 21)		
Commitments (note 17)		
	$ 611,543	$ 221,128

See accompanying notes to consolidated financial statements

Approved on behalf of the Board:

Keith Conrad
DIRECTOR

Bill Sliney
DIRECTOR

FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF EARNINGS AND ACCUMULATED EARNINGS

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

	YEAR ENDED DECEMBER 31, 2005	YEAR ENDED DECEMBER 31, 2004
		(restated note 3)
Revenues		
Oil and natural gas	$ 157,743	$ 108,293
Royalties	(36,079)	(24,527)
	121,664	83,766
Expenses		
Operating	32,620	23,492
General and administrative	10,331	4,440
Interest	4,715	2,222
Amortization of deferred financing charges	33	33
Depletion, depreciation and accretion	82,073	35,976
Goodwill impairment loss (note 7)	9,253	–
Financial derivative loss (gain) (note 15)	(354)	3,188
Foreign exchange gain	(715)	–
	137,956	69,351
Earnings (loss) before taxes and non-controlling interest	(16,292)	14,415
Income taxes (reduction) (note 14)		
Current	1,456	260
Future	(18,689)	(280)
Earnings before non-controlling interest	941	14,435
Non-controlling interest (note 12)	29	(408)
Net earnings	970	14,027
Accumulated earnings, beginning of year	27,498	13,139
Change in accounting policy related to EIC- 151 (note 3a)	–	332
Accumulated earnings, end of year	$ 28,468	$ 27,498
Net earnings per trust unit (note 13)		
Basic	$ 0.03	$ 0.62
Diluted	$ 0.03	$ 0.62

See accompanying notes to consolidated financial statements

FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF CASH FLOW

(Expressed in thousands of Canadian dollars)

	YEAR ENDED DECEMBER 31, 2005	YEAR ENDED DECEMBER 31, 2004
		(restated note 3)
Cash provided by (used in):		
Operating		
Net earnings	$ 970	$ 14,027
Depletion, depreciation and accretion	82,073	35,976
Goodwill impairment loss	9,253	–
Future income tax reduction	(18,689)	(280)
Amortization of deferred financing charges	33	33
Financial derivatives	(415)	–
Amortization of marketing contract	(2,667)	–
Non-controlling interest	(29)	408
Foreign exchange	(715)	–
Unit-based compensation	731	78
Changes in non-cash working capital items (note 16)	(2,425)	(7,897)
	68,120	42,345
Financing		
Distributions paid	(66,195)	(40,414)
Bank indebtedness	(27,709)	2,305
Notes payable	4,300	–
Capital lease	(805)	(783)
Deferred financing charges	(102)	–
Due to JED Oil Inc.	10,658	2,400
Issue of trust units, net of issue costs	37,353	36,838
Exercise of trust unit options	7,975	–
	(34,525)	346
Investing		
Property, plant and equipment additions	(31,217)	(30,409)
Deposit on acquisition	–	(385)
Proceeds on disposal of property, plant and equipment	–	1,177
Acquisition of Rocky Mountain Energy, net of cash (note 5)	–	(8,361)
Acquisition of Rocky Mountain Gas, net of cash (note 5)	(229)	–
Acquisition of High Point, net of cash (note 5)	1,282	–
Changes in capital accounts payable (note 16)	3,733	–
	(26,431)	(37,978)
Change in cash	7,164	4,713
Cash, beginning of period	4,779	66
Cash, end of period	$ 11,943	$ 4,779

During the year ended December 31, 2005 the Trust paid interest of $4,275,000 (2004 - $2,222,000) and taxes of $944,000 (2004 – $nil).

See accompanying notes to consolidated financial statements

FINANCIAL STATEMENTS

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As at December 31, 2005 and 2004 and for the years there ended (Expressed in Canadian Dollars)
(Tabular amounts are stated in thousands of dollars except unit and per unit information)

1. STRUCTURE OF THE TRUST AND BASIS OF PRESENTATION

Enterra Energy Trust ("the Trust") was established in November 2003 under a Plan of Arrangement. The Trust is an open-end unincorporated investment trust governed by the laws of the Province of Alberta and created pursuant to a trust indenture (the "Trust Indenture"). The purpose of the Trust is to indirectly hold interests in petroleum and natural gas properties, through notes from, and investments in securities of its subsidiaries. The beneficiaries of the Trust are the holders of the trust units (the "Unitholders").

The Trust pays monthly cash distributions to its unitholders in amounts equal to the net earnings of the Trust earned from interest income on the notes and from any dividends or note redemptions by the Trust's subsidiaries less any expenses of the Trust. The Board of Directors of Enterra Energy Corp. ("EEC"), as administrator of the Trust, has the discretion to determine the extent to which cash, in excess of the income on the notes, provided by operating activities will be distributed to the unitholders.

RELATIONSHIP WITH JED OIL INC. AND JMG EXPLORATION, INC.

Under an Agreement of Business Principles, properties acquired by the Trust will be contract operated and drilled by JMG Exploration, Inc. ("JMG"), a publicly traded oil and gas exploration company, if they are exploration properties, and contract operated and drilled by JED Oil Inc. ("JED"), a publicly traded oil and gas development company, if they are development projects. Exploration of the properties will be done by JMG, which will pay 100% of the exploration costs to earn a 70% working interest in the properties. If JMG discovers commercially viable reserves on the exploration properties, the Trust will have the right to purchase 80% of JMG's working interest in the properties at a fair value as determined by independent engineers. Should the Trust elect to have JED develop the properties, development will be done by JED, which will pay 100% of the development costs to earn 70% of the interests of both JMG and the Trust. The Trust will have a first right to purchase assets developed by JED. The Trust does not own any shares in either JMG or JED.

Effective January 1, 2004, the Trust and JED entered into a Technical Services Agreement, which provides for services required to manage the Trust's field operations and governs the allocation of general and administrative expenses between the two entities. Under the Technical Services Agreement, the Trust and JED allocate the costs of management, development, exploitation, operations and general and administrative activities on the basis of production and capital expenditures, or as otherwise agreed to between the Trust and JED. The Technical Services Agreement has no set termination date and can be cancelled with six months notice.

On January 1, 2006, the Trust terminated the Technical Services Agreement with JED. The Trust now manages its own management, development, exploitation, operations and general and administrative activities. In 2006, the Trust entered into a new agreement with JED where all services provide by JED to the Trust will be billed on an hourly rate basis.

On December 23, 2004, JED loaned $2,400,000 to the Trust. The terms of the loan called for interest to be calculated at a Canadian chartered bank prime lending rate plus 0.4% per annum. The loan, together with accrued interest, was repaid on March 18, 2005. At December 31, 2005, the Trust had $8,000,000 of unsecured notes payable to JED with an interest rate of 10% per annum. For the year ended December 31, 2005, $0.4 million (2004 - $nil) of interest was charged on the notes payable. In addition to the note, the Trust owed $7,151,000 (2004 - $2,093,000) to JED for general and administrative expenses and capital expenditures paid by JED on behalf of the Trust. For the year ended December 31, 2005, total general and administrative expenses charged by JED to the Trust on a cost recovery basis were approximately $3.9 million and field operating expenses charged by JED to the Trust on a cost recovery basis were approximately $3.0 million. On February 1, 2006, the Trust repaid the $8,000,000 notes payable to JED.

2. SIGNIFICANT ACCOUNTING POLICIES

Management of the Trust has prepared the consolidated financial statements in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). The significant differences between Canadian and United States GAAP are outlined in note 22. The following significant accounting policies are presented to assist the reader in evaluating these consolidated financial statements, and, together with the following notes, should be considered an integral part of the consolidated financial statements.

(a) Organization and Basis of Accounting

These consolidated financial statements include the accounts of the Trust and its subsidiaries and partnerships (collectively the "Trust" for purposes of the following notes to the consolidated financial statements). All inter-company accounts and transactions have been eliminated.

Substantially all exploration, development and production activities related to the Trust's oil and gas business are conducted jointly with others and the accounts reflect only the Trust's proportionate interest.

(b) Cash

Cash consists of cash on hand and balances invested in short-term securities with original maturities less than 90 days at the date of acquisition.

(c) Revenue Recognition

Revenue associated with the sale of crude oil, natural gas and natural gas liquids is recognized when title passes from the Trust to its customers based on contracts which establish the price of products sold.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As at December 31, 2005 and 2004 and for the years there ended (Expressed in Canadian Dollars)
(Tabular amounts are stated in thousands of dollars except unit and per unit information)

(d) Petroleum and Natural Gas Properties

The Trust follows the "full cost" method of accounting for petroleum and natural gas properties. All costs related to the exploration for and the development of 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.

Repair and maintenance costs are expensed as incurred.

(e) Impairment Test

The Trust places a limit on the carrying value of property and equipment, which may be depleted against revenues of future periods (the "ceiling test"). The ceiling test is conducted separately for each cost center, Canada and the United States. 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 carrying value of property and equipment subject to the ceiling test includes asset retirement costs.

(f) Per Unit Amounts

Per unit amounts are calculated using the weighted average number of units outstanding. The Trust follows the treasury stock method to determine dilutive effect of options, warrants and other dilutive instruments. Under the treasury stock method, only "in-the-money" dilutive instruments impact the diluted calculations. Exchangeable shares are included in the calculation of diluted earnings per unit based on the number of trust units that would be issued on conversion of the exchangeable shares at the end of the year as long as the conversion results in a decrease to earnings of the Trust.

(g) Estimates and Assumptions

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and the disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenue and expenses during the reporting periods.

The amounts recorded for depletion, depreciation and the asset retirement obligation are based on estimates. The ceiling test calculation is based on estimates of reserves, production rates, oil and natural gas prices, future 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 amounts recorded for financial derivatives are based on estimates of the price for oil and natural gas in future periods. These estimates are subject to fluctuations in market conditions and may impact the consolidated financial statements of future periods.

(h) Depletion and Depreciation

The provision for depletion of petroleum and natural gas properties is calculated, by cost center, using the unit-of-production method based on the Trust's share of estimated proved reserves before royalties. Natural gas reserves and production are converted to equivalent units of crude oil using their approximate relative energy content.

Office furniture and equipment is depreciated on a 20% declining balance basis.

(i) Goodwill

The Trust recognizes goodwill relating to acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities acquired. The goodwill balance is assessed for impairment annually at year-end or as events occur that could result in an impairment. To assess impairment, the fair value of the reporting unit is compared to its book value. If the fair value is less than the book value, a second test is performed to determine the amount of impairment. The amount of impairment is measured by allocating the fair value to the reporting unit's identifiable assets and liabilities as if it had been acquired in a business combination for a purchase price equal to its fair market value. If goodwill determined in this manner is less than the carrying value of goodwill, an impairment loss is recognized in the period in which it occurs. Goodwill is stated at cost less impairment. Goodwill is tested for impairment separately for the Canadian and the United States reporting units.

(j) Asset Retirement Obligations

The Trust recognizes a liability for the estimated fair value of the future retirement obligations associated with property and equipment. The fair value of the estimated asset retirement obligations is recorded as a liability with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on the unit-of-production method based on proved reserves. The Trust estimates the liability based on the estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. This estimate is evaluated on a periodic basis and any adjustment to the estimate is prospectively applied. As time passes, the change in net present value of the future retirement obligation is expensed through accretion. Retirement obligations settled during the period reduce the future retirement liability.

(k) Income Taxes

The Trust is a taxable entity under the Canadian Income Tax Act and is taxable only on income that is not distributed or distributable to the Trust's unitholders. As the Trust allocates all of its taxable income to the unitholders in accordance with the Trust Indenture, therefore no provision for income tax expense has been made in the Trust.

The Trust's corporate subsidiaries follow the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized based on the differences between the amounts reported in the financial statements of the Trust's corporate subsidiaries and their respective tax bases, using substantively enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

(l) Non-controlling Interest (note 3)

The Trust has, through its subsidiaries four types of exchangeable shares, Enterra Energy Corp. ("EEC") exchangeable shares, Rocky Mountain Acquisition Corp. ("RMAC") series A exchangeable shares, RMAC series B exchangeable shares and Rocky Mountain Gas ("RMG") exchangeable shares. The Trust's exchangeable shares are classified as non-controlling interest on the consolidated balance sheets. Income after tax attributable to these exchangeable shares is deducted from net earnings of the Trust on the consolidated statement of earnings.

When the EEC exchangeable shares are exchanged for trust units, they are measured at the fair value of the trust units issued. The amounts in excess of the carrying value of exchangeable shares are allocated to property, plant and equipment, to the extent possible, with any excess amounts being allocated to goodwill. When the other exchangeable shares are exchanged for trust units, they are measured at their carrying value.

(m) Derivative Financial Instruments

The Trust uses derivative financial instruments such as collars and swaps to manage its exposure to commodity price fluctuations. Actual amounts received, or paid, on the settlement of the derivative financial instruments is recorded in oil and gas revenue. The Trust uses the fair value method for reporting derivative financial instruments whereby a derivative financial instrument is recorded as an asset or a liability on the balance sheet, and changes in the fair value relating to a financial period are charged to net earnings and net earnings per unit for the period.

(n) Trust Unit Compensation Plans

The Trust has a unit based compensation plan, which is described in note 12. Compensation expense associated with the unit based compensation plan is recognized in earnings over the vesting period of the plan with a corresponding increase in contributed surplus. Any consideration received upon the exercise of the unit-based compensation together with the amount of non-cash compensation expense recognized in contributed surplus is recorded as an increase in unitholders' capital. Compensation expense is based on the fair value of the unit-based compensation at the date of grant using a Black-Scholes option-pricing model.

(o) Deferred Financing Charges

Deferred financing charges are amortized over the lives of their respective financing instruments.

(p) Foreign Currency Transactions

Transactions completed in United States dollars are reflected in Canadian dollars at the exchange rates prevailing at the time of the transactions. Current assets and liabilities denominated in United States dollars are reflected in the financial statements at the Canadian equivalent at the rate of exchange prevailing at the balance sheet date. Translation gains and losses are included in earnings.

The Trust's U.S. subsidiaries are considered to be "integrated foreign operations", therefore the Trust is using the temporal method of foreign currency translation. Under the temporal method, monetary items are translated at the exchange rate in effect at the balance sheet date, while non-monetary items are translated at historical exchange rates. Revenue and expense items are translated at the exchange rate in effect on the dates they occur, while depreciation and depletion of assets translated at historical exchange rates are translated at the same exchange rates as the assets to which they relate.

(q) Comparative Figures

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

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3. CHANGES IN ACCOUNTING POLICIES

a) Non-controlling Interest ("NCI")

On January 19, 2005, the CICA issued EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" that states that equity interests held by third parties in subsidiaries of an income trust should be reflected as either non-controlling interest or debt in the consolidated balance sheet unless they meet certain criteria. EIC-151 requires that the shares be nontransferable to be classified as equity. The Trust's exchangeable shares are transferable and, in accordance with EIC-151, have been reclassified to non-controlling interest on the consolidated balance sheets.

Prior to the adoption of EIC 151 trust units that would be issued upon conversion of exchangeable shares were included in the calculation of basic earnings per unit. As a result of the new standard exchangeable shares are excluded from the calculation of basic earnings per unit. However, they are included in the calculation of diluted earnings per unit.

Prior periods have been retroactively restated as required by the new accounting standard.

The following tables illustrate the impact of the new accounting policy as at and for the year ended December 31, 2004.

Balance Sheet as at December 31, 2004	Balance as reported prior to NCI restatement	Adjustments for NCI	Balance as restated
Property, plant and equipment	$ 146,910	$ 1,548	$ 148,458
Goodwill	29,991	19,279	49,270
Future income tax liability	21,526	602	22,128
Non-controlling interest	–	3,349	3,349
Unitholders' capital	111,653	20,554	132,207
Exchangeable shares	3,276	(3,276)	–
Accumulated earnings, beginning of year	13,139	332	13,471
Accumulated earnings, end of year	27,903	(405)	27,498
Basic weighted average number of units outstanding	23,327,728	(809,355)	22,518,373
Diluted weighted average number of units outstanding	23,560,785	(318,825)	23,241,960

Balance Sheet as at December 31, 2004	Balance as reported prior to NCI restatement	Adjustments for NCI	Balance as restated
Depletion, depreciation and accretion	$ 35,438	$ 538	$ 35,976
Future income tax recovery	(71)	(209)	(280)
Net earnings before non-controlling interest	14,764	(329)	14,435
Non-controlling interest	–	408	408
Net earnings	14,764	(737)	14,027
Net earnings per unit – basic	$ 0.63	$ (0.01)	$ 0.62
Net earnings per unit – diluted	$ 0.63	$ (0.01)	$ 0.62

b) Full Cost Accounting

Effective January 1, 2004, the Trust prospectively adopted new Canadian accounting standards relating to full cost accounting for oil and gas entities, as outlined in note 2. The new standard modifies the ceiling test to be performed in two stages. The first stage requires the carrying value to be tested for recoverability using undiscounted future cash flows from proved reserves using forward indexed prices. If the carrying value is not recoverable, the second stage, which is based on the calculation of discounted future cash flows from proved plus probable reserves, will determine the impairment to the fair value of the asset. There was no write down of the Trust's property and equipment as at January 1, 2004, as a result of adopting this standard.

c) Derivative Financial Instruments

On January 1, 2004, theTrust prospectively adopted new Canadian accounting standards relating to accounting for derivative financial instruments. The new standards establish certain conditions for when hedge accounting may be applied and addresses the identification, designation, documentation and effectiveness of hedging transactions. Where hedge accounting does not apply, any changes in the mark to market values of the derivative financial instrument relating to a financial period can either reduce or increase net earnings and net earnings per trust unit for that period. The Trust has elected not to apply hedge accounting to any of its financial instruments.

d) Asset Retirement Obligations

Effective January 1, 2004, the Trust retroactively adopted with restatement of prior periods, new Canadian accounting standards relating to asset retirement obligations as outlined in note 2. Prior to adopting the new standard, the Trust recognized a provision for future site restoration costs over the life of the oil and natural gas properties using a unit-of-production method.

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e) Unit-based compensation

Effective January 1, 2004, theTrust adopted the fair value method of accounting for options on a retroactive basis, without prior period adjustments. In the past, the Trust measured stock option compensation cost based on the intrinsic value of the award at the date of issuance. As the exercise price and the market price were the same at the date of grant, no compensation expense was recognized on any option issuance.

As a result of the adoption of this policy, the Trust recorded a charge to accumulated earnings of $646,000 as at January 1, 2004 to reflect the cost related to options granted in 2002 and 2003. In 2004, the earnings of the Trust were reduced by $78,000 as a result of this change in policy.

4. PROPERTY ACQUISITIONS

On January 26, 2005, the Trust acquired certain oil and natural gas properties in east central Alberta for consideration of $12,100,000. Results from operations of these acquired assets are included in the Trust's consolidated financial statements for the period subsequent to January 26, 2005. At December 31, 2004, the Trust had made a refundable deposit on the properties in the amount of $2,400,000.

On January 30, 2004, the Trust acquired certain oil and natural gas properties in East Central Alberta for consideration of $19,609,000. Results from operations of the East Central Alberta assets are included in the Trust's consolidated financial statements for the period subsequent to January 30, 2004.

5. CORPORATE ACQUISITIONS

Rocky Mountain Gas, Inc. ("RMG")

On June 1, 2005, the Trust acquired 100% of the issued and outstanding shares of RMG, an entity with natural gas properties in Montana and Wyoming. As RMG's properties are in the United States, they constitute a second cost center. RMG provides the Trust with future cash potential through the exploitation of coal bed methane on its undeveloped land as well as its currently producing assets. Results from operations of RMG subsequent to June 1, 2005 are included in the Trust's consolidated financial statements.

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

Allocation of purchase price:	
Current assets, including cash of $769	$ 1,606
Property, plant and equipment	34,809
Goodwill (with no tax base)	9,253
Marketing contract	(480)
Current liabilities	(1,562)
Debt	(4,229)
Asset retirement obligations	(3,807)
Future income tax liability	(11,619)
	$ 23,971

Cost of acquisition:	
Cash	$ 602
Transaction costs	396
736,842 RMG exchangeable shares	16,722
275,474 Trust Units	6,251
	$ 23,971

The purchase price allocation is preliminary and subject to change. The value assigned to each Enterra Trust Unit of $22.69 (US$18.35) was based on the weighted average trading price on the NASDAQ National Market System immediately prior to and after the measurement date.

High Point Resources Inc. ("High Point")

On August 17, 2005 the Trust completed the acquisition of 100% of the common shares of High Point through its subsidiary Rocky Mountain Acquisition Corp. ("RMAC") in exchange for 7,490,898 trust units and 1,407,177 RMAC exchangeable shares. High Point owns oil and natural gas properties predominantly in Alberta and British Columbia. The acquisition was completed to increase the Trust's natural gas portfolio. Results from operations of High Point subsequent to August 17, 2005 are included in the Trust's consolidated financial statements.

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

Allocation of purchase price:	
Current assets, including cash of $2,532	$ 12,306
Property, plant and equipment	351,385
Goodwill (with no tax base)	19,070
Current liabilities	(14,779)
Marketing contract	(3,634)
Debt	(75,000)
Asset retirement obligations	(2,653)
Future income tax liability	(85,239)
	$ 201,456

Cost of acquisition:	
7,490,898 Trust Units	$ 168,545
1,407,177 Exchangeable Shares	31,661
Transaction costs	1,250
	$ 201,456

The purchase price allocation is preliminary and subject to change. The value assigned to each Trust Unit and Exchangeable Share of $22.50 was based on the average trading price on the NASDAQ National Market System for the period prior to and after the measurement date.

Rocky Mountain Energy Corp. ("RMEC")

On September 29, 2004, the Trust acquired all of the issued and outstanding shares of RMEC through its subsidiary RMAC. RMEC owns oil and natural gas properties predominately in Alberta and British Columbia. Results from operations of RMEC subsequent to September 29, 2004 are included in the Trust's consolidated financial statements. The acquisition was accounted for using the purchase method of accounting with the allocation of the purchase price and consideration paid as follows:

Allocation of purchase price:	
Current assets, including cash of $16,270	$ 2,493
Property, plant and equipment	36,008
Goodwill (with no tax base)	30,761
Current liabilities	(2,849)
Bank indebtedness	(7,665)
Assets retirement obligations	(793)
Future income tax liability	(7,660)
	$ 50,295

Cost of acquisition:	
Cash	$ 7,234
Trust Units (1,946,576 issued)	34,999
RMAC Exchangeable Units (341,882 issued)	6,147
Transaction costs (including 38,726 units valued at $771,000)	1,915
	$ 50,295

For the initial transaction the value assigned to each Enterra trust unit of Cdn $17.98 was based on the weighted average trading price on the NASDAQ National Market System immediately prior to and after the measurement date. On February 17, 2005 an additional 38,726 units were issued to advisors as part of the transaction at a value of $771,000.

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6. PROPERTY, PLANT AND EQUIPMENT

			2005
	Cost	Accumulated depletion and depreciation	Net
Petroleum and natural gas properties	$ 644,260	$ 156,445	$ 487,815
Office furniture and equipment	2,781	1,522	1,259
	$ 647,041	$ 157,967	$ 489,074

			2004
	Cost	Accumulated depletion and depreciation	Net
Petroleum and natural gas properties	$ 223,637	$ 76,505	$ 147,132
Office furniture and equipment	2,158	832	1,326
	$ 225,795	$ 77,337	$ 148,458

During 2005, $49,000 of general and administrative expenses were capitalized and included in the cost of the petroleum and natural gas properties (2004 - $869,000).

At December 31, 2005, included in petroleum and natural gas properties are assets acquired and pledged under capital lease agreements with a cost base of $5,218,000 and net book value of $2,597,000 (2004 - $5,218,000 and $3,107,000).

At December 31, 2005 costs of undeveloped land and seismic of $58,353,000 (2004 - $6,728,873) were excluded from the calculation of depletion expense for the Canadian cost centre. At December 31, 2005 costs of undeveloped land of $13,313,103 were excluded from the calculation of depletion expense for the United States cost centre.

Depletion and depreciation expense related to the Canadian and the US cost center in 2005 was $64,626,000 and $16,004 respectively (2004 – the Trust did not have a US cost center).

The Trust completed a ceiling test calculation for the Canadian cost centre at December 31, 2005 to assess the recoverability of costs recorded in respect of the petroleum and natural gas properties. The petroleum and natural gas prices are based on the December 31, 2005 commodity price forecast of our independent reserve engineers. These prices have been adjusted for commodity price differentials specific to the Trust. The following table summarizes the benchmark prices used in the ceiling test calculation.

As at December 31, 2005 and 2004 and for the years there ended (Expressed in Canadian Dollars)
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Year	WTI Oil ($U.S./bbl)	Foreign Exchange Rate	Edmonton Light Crude Oil ($Cdn/bbl)	AECO Gas ($Cdn/GJ)
2006	57.50	1.1765	66.60	10.05
2007	55.40	1.1765	64.20	9.05
2008	52.40	1.1765	60.70	8.05
2009	49.50	1.1765	57.20	7.00
2010	46.90	1.1765	54.10	6.55
2011	48.10	1.1765	55.50	6.75
Escalate Thereafter	2.5% per year		2.5% per year	2.5% per year

A ceiling test write down in the Canadian cost center was not required at December 31, 2005.

The Trust completed a ceiling test calculation for the United States cost centre at December 31, 2005 to assess the recoverability of costs recorded in respect of the petroleum and natural gas properties. The petroleum and natural gas prices are based on the December 31, 2005 commodity price forecast of our independent reserve engineers. These prices have been adjusted for commodity price differentials specific to the Trust. The following table summarizes the benchmark prices used in the ceiling test calculation.

Year	WTI Oil ($U.S./bbl)	Foreign Exchange Rate	Henry Hub ($U.S./Mmbtu)
2006	57.50	1.1765	9.90
2007	55.40	1.1765	9.05
2008	52.40	1.1765	8.15
2009	49.50	1.1765	7.25
2010	46.90	1.1765	6.85
2011	48.10	1.1765	7.05
Escalate Thereafter	2.5% per year		Average 2.5% per year

The ceiling test in the U.S. cost center resulted in a write down of $13,844,000 ($9,137,000 after tax and a $0.31 reduction of earnings per unit) to property plant and equipment at December 31, 2005. This write down is included within depletion, depreciation and accretion on the consolidated statement of earnings.

7. GOODWILL

Due to the reduction in value of the U.S. cost center at December 31, 2005, as disclosed in note 6, goodwill in the United States reporting unit was deemed to be impaired. Accordingly, the Trust recorded a goodwill impairment loss of $9,253,000 in 2005.

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8. ASSET RETIREMENT OBLIGATIONS

The asset retirement obligations were estimated by management based on the Trust's working interest in its wells and facilities, estimated costs to remediate, reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred. At December 31, 2005, the Trust estimated the asset retirement obligation to be $24,323,000 (2004 – $14,836,000), based on a total future liability of $41,074,000 (2004 - $25,354,000). These obligations will be settled at the end of the useful lives of the underlying assets, which currently averages at 7 years, but extends up to 20 years into the future. This amount has been calculated using an inflation rate of 2% and discounted using a credit-adjusted risk-free interest rate of 8%.

The following table reconciles the asset retirement obligations:

	2005	2004
Asset retirement obligation, beginning of year	$ 14,836	$ 2,188
Increases in liabilities during the year related to:		
Acquisitions	6,460	10,512
Additions	1,911	262
Revisions	(327)	1,128
Accretion expense	1,443	867
Dispositions	–	(121)
Asset retirement obligation, end of year	$ 24,323	$ 14,836

9. BANK INDEBTEDNESS

On November 10, 2005 the Trust entered into an arrangement with a group of lenders for new credit facilities in the form of two revolving lines of credit that total $100,000,000 ($95,000,000 revolving facility and $5,000,000 operating facility). Drawings on the revolving facilities bear interest at 0.25% above the bank's prime lending rate or bankers' acceptance rates plus margins which were initially set at 135 basis points and will be subject to adjustment up or down prospectively, on a three-month basis as determined by the Trust's consolidated debt to cash flow ratio. Security is be provided by a first charge over all of the Trust's assets. The amounts available under these credit facilities are subject to a semi-annual borrowing base determination. The revolving facilities mature on November 9, 2006 with a 1 year term out period. On November 28, 2005, the Trust drew on the facilities and repaid its previous facilities and the bridge credit facility. As at December 31, 2005, the Trust had $95,450,000 drawn on the facilities at an interest rate of 5.25%. The new credit facilities require the Trust to comply with certain financial covenants including working capital and debt to equity ratios. Under the arrangement, the lenders can restrict the distributions of the Trust if the Trust is in default. At December 31, 2005, the Trust was in compliance with these covenants. In March 2006, the new credit facilities were replaced by a senior secured bridge facility (see note 21).

The Trust's previous facilities were two revolving lines of credit that had a total capacity of $41 million. Drawings on the revolving facilities bore interest at 1.6% above the bank's prime lending rate or bankers' acceptance rates plus margins which were originally set at 165 basis points and were subject to adjustment up or down prospectively, on a three-month basis as determined by the Trust's consolidated debt to cash flow ratio. At December 31, 2004 the Trust also had available a demand subordinated debt facility of $4,000,000 which bore interest at the lender's prime rate plus 2%, and this facility was reduced to nil on April 30, 2005. Security was provided by a first charge over all of the Trust's assets excluding those acquired in the RMG and High Point acquisitions. Amounts drawn on these facilities were repaid on November 28, 2005.

A bridge credit facility was put in place on August 17, 2005 to facilitate the acquisition of High Point. The bridge credit facility was a reducing non-revolving secured loan with a principal amount of $75,000,000. Security was provided by a first charge on all of the High Point assets that were acquired. The loan bore interest at bank prime rate plus 1% and was repayable from the proceeds of any debt or equity financing or proceeds from the disposal of assets. Amounts drawn on the bridge credit facility was repaid in full on November 28, 2005.

10. NOTES PAYABLE

Notes payable consists of an unsecured promissory note forUS$3.5 million (Cdn $4.1 million), which bears interest at 12%, and is repayable on July 1, 2006.

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11. CAPITAL LEASE OBLIGATION

Description	2005	2004
Capital lease bearing interest at 8.605%, repayable monthly at $88,802, including interest. The lease term is for 60 months, due October 1, 2007, with a purchase option of $1,000,000 and secured by the related equipment	$ 2,580	$ 3,385
Less current portion	(878)	(805)
	$ 1,702	$ 2,580

Interest expense includes $260,000 (2004 - $327,000) related to the capital leases.

12. NON-CONTROLLING INTEREST

Number of exchangeable shares issued	EEC	RMAC series A	RMG	RMAC series B	Total
Balance at December 31, 2003	1,995,596	–	–	–	1,995,596
Issued on acquisition of RMEC	–	341,882	–	–	341,882
Exchanged for trust units	(1,584,826)	(199,438)	–	–	(1,784,264)
Balance at December 31, 2004	410,770	142,444	–	–	553,214
Issued on acquisition of RMG	–	–	736,842	–	736,842
Issued on acquisition of High Point	–	–	–	1,407,177	1,407,177
Exchanged for trust units	(62,624)	(142,444)	–	(748,061)	(953,129)
Balance at December 31, 2005	**348,146**	**–**	**736,842**	**659,116**	**1,744,104**

Non-controlling interest	Amount
Balance at December 31, 2003	$ 3,125
Issued on acquisition of RMEC	6,410
Exchanged for trust units	(6,594)
Non-controlling interest in net earnings	408
Balance at December 31, 2004	$ 3,349
Issued on acquisition of RMG	16,722
Issued on acquisition of High Point	31,661
Exchanged for trust units	(19,301)
Non-controlling interest in net earnings	(29)
Balance at December 31, 2005	**$ 32,402**

With the exception of the RMG exchangeable shares, the exchangeable shares are convertible at any time into trust units (at the option of the holder) based on the exchange ratio. The exchange ratio for RMAC series A exchangeable shares, RMAC series B exchangeable shares and Enterra Energy Corp. exchangeable shares are increased monthly based on the cash distribution paid on the trust units divided by the ten day weighted average unit price preceding the distribution payment date. Cash distributions are not paid on the exchangeable shares. On the third anniversary of the issuance of the exchangeable shares, subject to extension of such date by the Board of Directors of the Trust, or at the Trust's option when the aggregate number of issued and outstanding exchangeable shares is less than 1,000,000, the exchangeable shares will be redeemed for Trust Units at a redemption price per Exchangeable Share equal to the value of that number of Trust Units equal to the exchange ratio as at that redemption date. RMG exchangeable shares do not have an exchange ratio and will be exchanged automatically for one trust unit on June 1, 2006. The exchangeable shares are not listed for trading on an exchange.

During 2005, a total of 62,624 Enterra Energy Corp. exchangeable shares were converted into 73,432 trust units at an exchange ratio prevailing at the time of conversion (2004 – 1,584,826 exchangeable shares were converted into 1,622,780 trust units). During 2005, a total of 142,444 RMAC series A exchangeable shares were converted into 147,636 trust units at an exchange ratio prevailing at the time of conversion (2004 – 199,438 exchangeable shares were converted into 202,084 trust units). During 2005, a total of 748,061 RMAC series B e xchangeable shares were converted into 758,109 trust units at an exchange ratio prevailing at the time of conversion. The exchange of the EEC exchangeable shares is treated as a step acquisition which increased goodwill by $1.4 million for the difference between the fair value of the trust unit issued and the carrying value of the EEC exchangeable share at the time of exchange.

At December 31, 2005, the exchange ratio for Enterra Energy Corp. exchangeable shares was 1.20694 and for RMAC series B exchangeable shares was 1.03175.

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13. UNITHOLDERS' EQUITY

Authorized trust units

An unlimited number of trust units may be issued.

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

Issued trust units

	Number of Units	Amount
Balance at December 31, 2003	18,955,960	$ 32,879
Adopt fair value method of unit based compensation (note 3(e))	–	646
Issued pursuant to private placements	2,699,400	37,676
Issued pursuant on acquisition of RMAC	1,946,576	34,999
Issued for exchangeable shares	1,824,864	26,844
Unit share issue costs	–	(837)
Balance at December 31, 2004	25,426,800	$ 132,207
Issued on exercise of options	536,762	8,211
Issued pursuant to acquisition of RMAC	38,726	771
Issued pursuant to acquisition of RMG	275,474	6,251
Issued pursuant to acquisition of High Point	7,490,898	168,545
Issued pursuant to private placements	1,756,579	38,110
Issued for exchangeable shares	979,177	20,587
Unit issue costs	–	(921)
Balance at December 31, 2005	**36,504,416**	**$ 373,761**

Available equity offering

In April 2005, the Trust entered into an agreement with Kingsbridge Capital Limited ("Kingsbridge") whereby they agreed to purchase up to US$100 million of trust units over a two-year period. The Trust has no obligation to access any of the available capital, but may do so at its option. The subscription price of the Trust Units on each drawdown will be 92% of the fifteen day volume weighted average trading price of the Trust Units on the NASDAQ provided that the price must be at least US$12.00 and not less than the minimum price permitted by the rules of the Toronto Stock Exchange. The first draw may be up to US$25 million, and each subsequent draw can be up to the lesser of 4% of the Trust's market capitalization or US$25 million. As at December 31, 2005, the Trust has issued Cdn $15.8 million under the agreement.

In April 2005, the Trust granted warrants to Kingsbridge to purchase 301,000 trust units. The warrants have a three-year term. The exercise price of the warrants was initially US$25.77 per trust unit and is reduced each month by the amount of the Trust's distribution for such month on the trust units, provided that the price shall not decrease below US$21.55 per trust unit. As at December 31, 2005 the exercise price of the warrants was US$24.45. The fair value of the warrants has been reflected as deferred financing costs to be transferred to trust unit issue costs as the Trust issues new trust units under the Kingsbridge agreement.

The fair value of the warrants was estimated using the Black-Scholes model under the following assumptions:

Weighted-average fair value of warrants granted ($/warrant)	$ 4.04
Risk-free interest rate (%)	3.6
Estimated hold period prior to exercise (years)	3
Weighted-average volatility (%)	33
Cash distribution yield (%)	9

Contributed surplus

Balance at December 31, 2003	$ –
Trust unit option based compensation	78
Balance at December 31, 2004	$ 78
Trust unit option based compensation	731
Transfer to trust units on option exercises	(236)
Balance at December 31, 2005	**$ 573**

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Trust unit options

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

The following options have been granted:

		2005		2004
	Number of options	Weighted-average exercise price	Number of options	Weighted-average exercise price
Options outstanding, beginning of year	950,000	$ 14.22	–	$ –
Options granted	1,461,500	23.88	950,000	14.22
Options exercised	(536,762)	14.86	–	–
Options cancelled	(443,333)	17.15	–	–
Options outstanding, end of year	1,431,405	$ 22.31	950,000	$ 14.22
Options exercisable at end of year	69,905	$ 14.98	–	$ –

	Unit options outstanding		Unit options exercisable	
Exercise price range	Number of options	Weighted average remaining contract life	Number of options	Weighted average remaining contract life
$14.00 to $20.85	214,905	4.05	69,905	3.15
$23.15 to $29.31	1,216,500	4.34	–	–
	1,431,405	4.30	69,905	3.15

Estimated fair value of stock options
The estimated fair value of options was determined using the Black-Scholes model under the following assumptions:

	2005	2004
Weighted-average fair value of options granted ($/option)	$ 2.35	$ 0.33
Risk-free interest rate (%)	3.7	3.8
Estimated hold period prior to exercise (years)	5	5
Expected volatility (%)	36	21
Expected cash distribution yield (%)	10	11

Reconciliation of earnings per unit calculations

For the year ended December 31, 2005

	Net Earnings	Weighted Average Units Outstanding	Per Unit
Basic	$ 970	29,533,577	$ 0.03
Options assumed exercised		1,277,405	
Units assumed purchased		(1,122,153)	
Diluted	$ 970	29,688,829	$ 0.03

For the calculation of the weighted average number of diluted units outstanding for 2005, 154,000 options, 301,000 warrants and 1,300,453 exchangeable shares were excluded, as they were antidilutive to the calculation.

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For the year ended December 31, 2004	Net Earnings	Weighted Average Units Outstanding	Per Unit
Basic	$ 14,027	22,518,373	$ 0.62
Exchangeable shares / Non-controlling interest	408	490,530	
Options assumed exercised		950,000	
Units assumed purchased		(716,943)	
Diluted	$ 14,435	23,241,960	$ 0.62

Tust unit savings plan

In 2004, theTrust established a trust unit savings plan whereby the Trust will match an employee's contributions to the plan to a maximum of 9.0% of their salary. Both the employee's and the Trust's contributions were used to purchase trust units on the NASDAQ National Markets system (commencing in 2006, on the New York Stock Exchange). During 2005 the Trust expensed approximately $25,000 (2004 - $23,000) relating to the Trust's contributions to the plan.

14. INCOME TAXES

The income tax provision is calculated by applying Canadian federal and provincial statutory tax rates to pre-tax earnings with adjustments as set out in the following table:

	2005	2004
Earnings (loss) before income taxes and non-controlling interest	$ (16,292)	$ 14,415
Combined federal and provincial income tax rate	37.62%	38.87%
Computed income tax provision	(6,129)	5,603
Increase (decrease) resulting from:		
Interest component of trust distributions	(11,593)	(7,038)
Non-deductible royalties, net of ARTC	5,538	(4,669)
Resource allowance	(11,110)	5,239
Non-deductible items including goodwill impairment loss	3,536	–
Difference between U.S. and Canadian tax rates	(60)	–
Change in estimates	1,201	–
Capital tax	1,456	260
Other	(72)	585
	$ (17,233)	$ (20)

The components of the net future income tax liability at December 31 were as follows:

	2005	2004
Future income tax assets:		
Non-capital loss carry-forwards	$ 21,573	$ 12,127
Asset retirement obligations	8,177	4,988
Deferred financing charges	1,219	179
	$ 30,969	$ 17,294
Future income tax liabilities:		
Property, plant and equipment	131,266	39,422
Net future income tax liability	$ 100,297	$ 22,128

At December 31, 2005, the property, plant and equipment owned by the Trust's corporate subsidiaries have an approximate tax basis of $179,001,000 (2004 - $126,800,000) available for future use as deductions from taxable income. Non-capital loss carry-forwards expire from 2007 to 2015.

Tax rate applied to temporary difference is approximately 34% in 2005 (35% in 2004) compared to the federal and provincial statutory rate of 38% for the 2005 year.

As at December 31, 2005 and 2004 and for the years there ended (Expressed in Canadian Dollars)
(Tabular amounts are stated in thousands of dollars except unit and per unit information)

15. FINANCIAL INSTRUMENTS

The financial instruments recognized on the consolidated balance sheets include cash, accounts receivable, accounts payable and accrued liabilities, distributions payable to unitholders, income taxes payable, bank indebtedness, notes payable, due to JED Oil Inc., capital lease and financial derivatives. The fair values of financial instruments other than the capital lease and bank indebtedness approximate their carrying amounts due to the short-term nature of the instruments. The carrying value of bank indebtedness approximates its fair value due to floating interest terms; the fair value of the capital lease approximates its carrying value due to current rates for comparable terms of long-term debt. The financial derivative contracts are held at fair value with the gains and losses included within earnings for the period.

The Trust is exposed to fluctuations in commodity prices, foreign-currency exchange rates, interest rates and credit risk. The Trust manages its operations to minimize the exposure to these risks to the extent practical and, to a lesser extent, using derivative instruments and physical sales contracts. The Trust uses non-exchange traded forwards, swaps, options and physical deliver contracts to manage a portion of the Trust's commodity price risk. Management monitors the Trust's exposure to the above risks and regularly reviews its derivative activities and all outstanding positions.

(a) Commodity price risks

The Trust's most significant market risk exposure relates to crude oil price fluctuations. To a lesser extent the Trust is also exposed to natural gas price movements.

The Trust has entered into derivative financial instruments and fixed price physical contracts to minimize the risk of exposure to fluctuations in the crude oil and natural gas prices. At December 31, 2005, the Trust had the following financial derivatives outstanding:

Derivative Instrument	Commodity	Price	Volume (per day)	Period
Floors	Gas	9.65 to 9.80 (Cdn $/GJ)	10,000 GJ	January 1, 2006 – April 1, 2006
Collars	Gas	8.50 to 14.00 (Cdn $/GJ)	10,000 GJ	April 1, 2006 – November 1, 2006
Collars	Oil	55.00 to 70.25 (US$/bbl)	1,000 bbl	January 1, 2006 – January 1, 2007
Collars	Oil	55.00 to 80.00 (US$/bbl)	1,000 bbl	April 1, 2006 – January 1, 2007

The fair market value of the financial derivatives at December 31, 2005 is estimated to be $415,000. Fees of $60,000 associated with these hedges were netted against the gain. At December 31, 2004 the Trust did not have any derivative financial instruments or fixed price physical sales contracts in place.

At December 31, 2005, the Trust had the following fixed price physical delivery contracts outstanding:

	Contract Period End	Quantity	Pricing (Cdn $/GJ)
Natural Gas Contracts	March 31, 2006	8,000 GJ/day	$8.01 to $8.85

(b) Foreign currency exchange risk

The Trust is exposed to foreign currency fluctuations as crude oil and natural gas prices received are referenced to U.S. dollar denominated prices. The Trust's U.S. subsidiary operates in a foreign currency which is translated to Canadian dollars as described in note 2(p). These operations are exposed to currency fluctuations.

(c) Credit risk

A substantial portion of the Trust's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Trust's natural gas, crude oil and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment. As at December 31, 2005 the Trust had recorded $1,504,000 (2004 - $1,496,000) as an allowance for doubtful accounts.

(d) Interest rate risk

Interest rate risk exists principally with respect to our indebtedness that bears interest at floating rates. At December 31, 2005, the Trust had $95,450,000 (2004 - $43,930,000) of indebtedness bearing interest at floating rates. The balance of the Trust's indebtedness being the capital lease, due to Jed Oil Inc. and the note payable bear interest at fixed rates.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As at December 31, 2005 and 2004 and for the years there ended (Expressed in Canadian Dollars)
(Tabular amounts are stated in thousands of dollars except unit and per unit information)

16. CHANGES IN NON-CASH WORKING CAPITAL

	2005	2004
Accounts receivable	$ (9,684)	$ (4,393)
Prepaid expenses, deposits and other	(1,929)	(57)
Accounts payable and accrued liabilities	8,356	(3,607)
Income taxes payable	346	160
Foreign exchange on working capital	486	–
Changes in non-cash working capital	$ (2,425)	$ (7,897)
Changes in capital accounts payable	$ 3,733	–

17. COMMITMENTS

The Trust has commitments for the following payments over the next six years:

	2006	2007	2008	2009	2010	2011
Minimum capital lease payments	$ 878	$ 1,702	$ –	$ –	$ –	$ –
Imputed Interest on capital lease	187	97	–	–	–	–
Office leases	1,160	1,060	1,080	1,082	1,175	97
	$ 2,225	$ 2,859	$ 1,080	$ 1,082	$ 1,175	$ 97

During 2005 total rental expense was $423,000 (2004 - $81,339).

18. GUARANTEES

The Trust has indemnified all of the directors and officers of the Trust and all the officers, directors, shareholders, employees and agents of JED. There is no pending litigation or proceeding for which a claim is being sought, nor is the Trust aware of any threatened litigation that may result in claims.

19. SEGMENTED INFORMATION

The Trust has one operating segment that is divided amongst two geographical areas. The follow is select financial information from the two geographic areas for 2005. The Trust operated only in Canada for 2004.

For the year ended and as at December 31, 2005	Canada	U.S.	Total
Revenue	$ 154,412	$ 3,331	$ 157,743
Property, plant and equipment	469,503	19,571	489,074
Goodwill	$ 70,546	$ –	$ 70,546

20. RELATED PARTIES

During 2005 the Trust paid $350,000 to Macon Resources Ltd. (“Macon”), a company 100% owned by the Chief Executive Officer of the Trust, for management services provided by the Chief Executive Officer and the Chief Financial Officer. During 2005, the Trust issued 400,000 trust unit options to Macon at $23.96 per option. The options have a 5-year life and vest over a 3-year period. See note 13 for further discussion on the Trust’s unit option plan. At December 31, 2005 $84,000 (2004 - $ nil) was payable by the Trust to Macon.

21. SUBSEQUENT EVENTS

During the first quarter of 2006, the Trust acquired producing oil and gas assets located in Oklahoma. The Trust expects to complete a final closing for additional working interests in the first half of 2006. The current operating staff of the assets is being retained by the Trust.

The purchase price of US$221.0 million was paid for through the issuance of 5,178,792 units of the Trust valued at USD $91.7 million, cash of US$102.3 million and US$27.0 million of assumed debts. Certain post closing purchase price adjustment provisions remain in place, based on production rates achieved from the assets through September 19, 2006. The purchase price on the final closing of the additional working interests is expected to be paid with a combination of units and cash.

The Trust is in the process of entering into a farmout agreement with Petroflow Energy Inc. ("Petroflow"), an oil and gas development company, to fund 100% of the drilling and completion costs on the undeveloped lands. The Chief Executive Officer for the Trust owns, directly and indirectly, approximately 20% of the outstanding shares of Petroflow.

In January 2006, the Trust entered into an arrangement with a bank for a US$50.0 million bridge credit facility. This credit facility was used to secure the acquisition of the Oklahoma assets. The facility was a reducing non-revolving loan secured by a first charge over the notes from the sellers of the Oklahoma assets, which were secured by the Oklahoma assets. The loan bore interest at U.S. dollar commercial loan rate plus 0.5% and was repaid on March 22, 2006.

In March 2006, the Trust closed a US$200.0 million senior secured bridge credit facility to partially fund the acquisition of the Oklahoma assets, repay the USD $50.0 million bridge credit facility noted above and provide additional working capital to the Trust. This non-revolving facility bears interest at 4.5% above London Interbank Offering Rate and matures September 20, 2006 with a one-time option to extend the facility for an additional three-month period. The facility is secured by a first charge over all US assets of the Trust and a second charge over all Canadian assets. The terms of the agreement restrict the Trust's ability to distribute cash flow from the U.S. cost center to US$1.5 million per month. The credit facility also requires the Trust to maintain certain financial covenants.

In March 2006, the Trust closed a $110.0 million senior secured bridge facility. This reducing non-revolving credit facility was used to retire the existing $100.0 million credit facilities of the Trust. The facility bears interest at 2.5% above bank prime lending rates and matures on December 31, 2006. The facility is reduced to $100 million on June 30, 2006. The facility is secured by a first charge over all Canadian assets of the Trust and a second charge over all US assets. The credit facility also requires the Trust to maintain certain financial covenants.

The Trust does not expect to repay the two bridge facilities from internally generated cash and will need to seek additional financing through the issuance of debt or equity.

22. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Trust's consolidated financial statements have been prepared in Canadian Dollars and in accordance with generally accepted accounting principles in Canada ("Canadian GAAP"), which differ in certain respects from those in the United States of America ("U.S. GAAP"). Any differences in accounting principles as they pertain to the consolidated financial statements as at December 31, 2005 and 2004 and for the years there ended were insignificant except as described below:

(a) Property, plant and equipment

Under Canadian GAAP, the impairment test limits the capitalized costs of oil and natural gas assets to the discounted estimated future net revenue from proved and probable oil and natural gas reserves using forecast prices plus the costs of unproved properties less impairment. The discount rate used is a risk free interest rate.

Under U.S. GAAP, the full cost method of accounting for oil and natural gas activities requires the Trust to perform an impairment test using after-tax future net revenue from proved oil and natural gas reserves discounted at 10% plus the cost of unproved properties less impairment. The prices and costs used in the U.S. GAAP ceiling test are those in effect at the period end. Where the amount of a ceiling test write-down under Canadian GAAP differs from the amount of the write-down under U.S. GAAP, the charge for depletion will differ in the year and subsequent years.

There were ceiling test impairments recognized under U.S. GAAP at December 31, 2005, 2004 and 2001. At December 31, 2005, the Trust recognized a U.S. GAAP ceiling test write-down of $34.1 million ($22.5 million after tax) in its Canadian cost center and an additional $3.0 million ($2.0 million after tax) ceiling test write down in its US cost center. At December 31, 2004 the Trust recognized a U.S. GAAP ceiling test write-down of $10.0 million ($6.3 million after tax) and at December 31, 2001 the Trust recognized a write-down of $28.7 million ($17.5 million after tax).

Under Canadian GAAP, pursuant to EIC 151, property, plant and equipment increased as a result of the conversion of one class of exchangeable shares into trust units. Under U.S. GAAP, all clases of exchangeable shares are classified as mezzanine equity, valued at the fair market value and conversion of exchangeable shares does not result in an increase in property, plant and equipment. This GAAP difference in the valuation of property, plant and equipment results in an increase in depletion expense during the periods presented for Canadian GAAP as compared with U.S. GAAP (see note f).

These property, plant and equipment valuation differences result in depletion expense being different under U.S. GAAP as compared with Canadian GAAP. For the year ended December 31, 2005 depletion, including the ceiling test writedowns under U.S. GAAP was higher by $30.0 million ($19.8 million after tax) (2004 - $8.0 million and $4.9 million after tax).

(b) Financial instruments and Marketing Contracts

Prior to the Trust adopting AcG-13 in 2004 for Canadian GAAP purposes, a US GAAP difference existed in that SFAS 133, "Accounting for Derivative Instruments and Hedging Activities" requires that all derivative instruments be recorded on the consolidated balance sheet as either an asset or liability measured at fair value, and requires that changes in fair value be recognized in income unless specific hedge accounting criteria are met. Hedge accounting requires that an entity formally document, designate and assess the effectiveness of derivative instruments to use this accounting treatment.

At December 31, 2005, Enterra had several physical delivery commodity contracts in place. Under Canadian GAAP, physical delivery contracts are not considered financial instruments and would normally not be measured at fair value on the balance sheet. For US GAAP, the Trust did not formally document and designate these outstanding contracts as physical sales contracts, therefore the contracts are re-valued each period end to market value (mark-to-market).

Under Canadian GAAP, the physical sales contracts are recorded on the balance sheet at the amortized cost of $1.4 million as a result of the contracts being acquired with High Point. At December 31, 2005, the fair value of the contracts is $1.3 million resulting in a reduction to the marketing liability recorded on the balance sheet and an increase in earnings under US GAAP of $0.2 million ($0.1 million after tax).

The Trust did not have any derivative instruments or hedging contracts outstanding at December 31, 2004.

(c) Earnings

Under U.S. GAAP, interest and amortization of deferred financing charges would be presented in the non-operating section of the statement of earnings.

(d) Comprehensive Income

There are no items that would be part of Comprehensive Income other than net earnings.

(e) Unitholder's Mezzanine equity

Under Canadian GAAP, the trust units are considered to be permanent equity and are classified as unitholders' capital. A U.S. GAAP difference exists due to the redemption feature attached to each trust unit. The trust units are redeemable at the option of the holder based on the lesser of 90% of the average market trading price of the trust units for the 10 trading days after the date of redemption or the closing market price of the trust units on the date of redemption. Trust units can be redeemed to a cash limit of $100,000 per year or a greater limit at the discretion of the Trust. Redemptions in excess of the cash limit shall be satisfied first by the issuance of notes by a subsidiary of the Trust and second by issuance of promissory notes by the Trust.

The redemption feature causes the trust units to be classified as mezzanine equity under U.S. GAAP. Mezzanine equity is valued at an amount equal to the redemption value of the trust units at the balance sheet date. Included in the redemption value of the trust units is the redemption value of the exchangeable shares as if all exchangeable shares had previously been converted into trust units. Any increase or decrease in the redemption value during a period is charged to accumulated earnings and reflected in the calculation of net earnings per trust unit.

As at December 31, 2005, unitholders' capital was reduced by $373.8 million and non-controlling interest was reduced by $32.4 million (2004 - $132.2 million and $3.3 million respectively) and the redemption value of the trust units and exchangeable units of $684.0 million (2004 - $529.8 million) was recorded as mezzanine equity. The change in the redemption value of the trust units and exchangeable units is recorded as a reduction or credit to accumulated earnings. For the year ended December 31, 2005 accumulated earnings was creditedby $115.1 million (2004 – reduced by $190.0 million).

(f) Exchangeable Securities Issued by Subsidiaries of Income Trusts pursuant to EIC-151

On January 19, 2005, the CICA issued EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" that states that equity interests held by third parties in subsidiaries of an income trust should be reflected as either non-controlling interest or debt in the consolidated balance sheet unless they meet certain criteria. EIC-151 requires that the shares be nontransferable to be classified as equity. The Trust's exchangeable shares are transferable and, in accordance with EIC-151, have been reclassified to non-controlling interest on the Canadian GAAP consolidated balance sheets.

Since a portion of Enterra's exchangeable shares were not initially recorded at fair value, subsequent exchanges for Trust Units are measured at the fair value of the Trust Units issued. The excess of fair values over book values on the exchange are recorded as additions to property, plant and equipment and goodwill. In addition, non-controlling interest is reflected as a reduction of such earnings in the Trust's consolidated statements of earnings.

The application of EIC-151 causes several differences with U.S. GAAP. As at December 31, 2005, property, plant and equipment increased by $1.4 million (December 31, 2004 - $1.5 million), goodwill increased by $20.7 million (December 31, 2004 - $19.3 million), future income tax liability increased by $0.6 million (December 31, 2004 - $0.6 million), unitholder capital increased by $21.9 million (December 31, 2004 - $20.6 million), accumulated earnings decreased by $0.4 million (December 31, 2004 - $0.4 million). In addition, depletion expense under Canadian GAAP is higher as a result of the increase in the property, plant and equipment value.

As at December 31, 2005 and 2004 and for the years there ended (Expressed in Canadian Dollars)
(Tabular amounts are stated in thousands of dollars except unit and per unit information)

(g) Consolidated Balance Sheets

The adjustments using U.S. GAAP would result in the following changes to the consolidated balance sheets of the Trust:

	December 31, 2005		December 31, 2004	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Assets				
Current assets	$ 50,713	$ 50,713	$ 20,910	$ 20,910
Deposit on acquisitions	–	–	2,400	2,400
Property, plant and equipment (a) (f)	489,074	428,678	148,458	117,940
Goodwill (f)	70,546	49,832	49,270	29,991
Deferred financing charges	1,210	1,210	90	90
	$ 611,543	$ 530,433	$ 221,128	$ 171,331
Liabilities				
Current liabilities (b)	$ 163,110	$ 162,956	$ 63,264	$ 63,264
Asset retirement obligations	24,323	24,323	14,836	14,836
Future income tax liability (a) (b) (f)	100,297	78,631	22,128	10,614
Capital lease	1,702	1,702	2,580	2,580
	289,432	267,612	102,808	91,294
Mezzanine equity (e)	–	684,024	–	529,764
Non-controlling interest (e) (f)	32,402	–	3,349	–
	32,402	684,024	3,349	529,764
Unitholders' equity				
Unitholders' capital (e) (f)	373,761	–	132,207	–
Warrants	1,215	1,215	–	–
Contributed surplus	573	573	78	78
Accumulated earnings (deficit)	28,468	(308,683)	27,498	(404,993)
Accumulated distributions	(114,308)	(114,308)	(44,812)	(44,812)
	289,709	(421,203)	114,971	(449,727)
	$ 611,543	$ 530,433	$ 221,128	$ 171,331

(h) Consolidated Statements of Earnings

The adjustments using U.S. GAAP would result in the following changes to the consolidated statements of earnings of the Trust:

	Years Ended December 31, 2005	Years Ended December 31, 2004
Net earnings under Canadian GAAP	$ 970	$ 14,027
Adjustments:		
Depletion expense (a)	(30,027)	(7,467)
Related income taxes	10,209	2,802
Unrealized loss on financial instruments (b)	154	958
Related income taxes	(57)	(390)
Non-controlling interest (f)	(29)	408
Net earnings (loss) under U.S. GAAP before change in redemption value of trust units	(18,780)	10,338
Change in redemption value of trust units (e)	115,090	(189,970)
Net earnings (loss) under U.S. GAAP after change in redemption value of trust units	$ 96,310	$ (179,632)
Weighted average units for U.S. GAAP (000's)		
- Basic	30,834	23,328
- Diluted	30,989	23,561
Net earnings per unit under U.S. GAAP - before changes in redemption value of trust units		
- Basic	$ (0.61)	$ 0.44
- Diluted	$ (0.61)	$ 0.44
Net earnings (loss) per unit under U.S. GAAP		
- Basic	$ 3.12	$ (7.70)
- Diluted	$ 3.11	$ (7.70)

As at December 31, 2005 and 2004 and for the years there ended (Expressed in Canadian Dollars)
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(i) Additional disclosure under U.S. GAAP

	December 31, 2005	December 31, 2004
Components of accounts receivable		
Trade	$ 18,367	$ 8,095
Accruals	18,440	9,014
Allowance for doubtful accounts	(1,504)	(1,496)
	$ 35,303	$ 15,613
Components of prepaid expenses		
Prepaid expenses	$ 1,025	$ 278
Funds on deposit	2,027	240
	$ 3,052	$ 518
Components of accounts payable		
Accounts payable	$ 28,306	$ 3,928
Accrued liabilities	8,042	4,642
	$ 36,348	$ 8,570

(j) Select pro forma financial information for High Point acquisition (unaudited)

As shown in note 5 of the CanadianGAAP financial statements, the Trust completed the acquisition of High Point. Under U.S. GAAP, select pro forma financial information is disclosed as if the acquisition had occurred on January 1, 2004 and 2005 instead of the actual closing of August 17, 2005. The following table shows the pro forma U.S. GAAP select financial information for the acquisition of High Point.

	December 31, 2005 (unaudited)	December 31, 2004 (unaudited)
Revenue	$ 191,247	$ 152,450
Net loss before change in redemption value of trust units	$ (18,804)	$ (2,553)
Per unit - basic	$ (0.52)	$ (0.08)
Per unit - diluted	$ (0.52)	$ (0.08)
Net earnings (loss)	$ 97,977	$ (241,640)
Per unit - basic	$ 2.69	$ (7.50)
Per unit - diluted	$ 2.68	$ (7.50)

(k) New accounting pronouncements

i) On June 1, 2005 FASB issued Statement No. 154, Accounting Changes and Error Correction. The statement applies to all voluntary changes in accounting principles and changes the requirement for accounting for and reporting of a change in accounting principle. Statement 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005.

Statement 154 requires, whenever practical, the retroactive application to prior periods' financial statements of a voluntary change in accounting principles. If not practical then certain concessionary transition accounting standards are permitted. The previous rules in Opinion 20 required that voluntary changes in accounting principles be recognized in net income in the period when the change in the accounting principle is adopted.

The impact of this standard on the consolidated financial statements will be dependent on the nature and extent of subsequent new and revised accounting standards.

ii) In December 2004, the FASB issued FAS 153 which deals with the accounting for the exchanges of non-monetary assets. FAS 153 is an amendment of APB Opinion 29. APB Opinion 29 requires that exchanges of non-monetary assets should be measured based on the fair value of the assets exchanged. FAS 153 amends APB Opinion 29 to eliminate the exception from using fair market value for non-monetary exchanges of similar productive assets and introduce a broader exception fro exchanges of non-monetary assets that do not have commercial substance. FAS 153 is effective for non-monetary asset exchanges occurring in fiscal periods beginning after June 15, 2005 Adopting the provisions of FAS 153 is not expected to impact the U.S. GAAP financial statements.

As at December 31, 2005 and 2004 and for the years there ended (Expressed in Canadian Dollars)
(Tabular amounts are stated in thousands of dollars except unit and per unit information)

iii) In December 2004, the FASB issued FAS 123R which deals with the accounting for transactions in which an entity exchanges its equity instruments for goods or services. FAS 123R also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. FAS 123R focuses primarily on accounting for transactions in which an entity obtains employee services in unit (share)-based payment transactions. FAS 123R is a revision of FAS 123. FAS 123R requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award (with limited exceptions). That cost will be recognized over the period during which an employee is required to provide service in exchange for the award – the requisite service period (usually the vesting period). FAS 123R is effective January 1, 2006. Since January 1, 2004, the Trust has recognized the costs of equity instruments issued in exchange for employee services based on the grand-date fair value of the award, in accordance with Canadian GAAP. The methodology for determining fair value of equity instruments issued in exchange for employee services prescribed by FAS 123R differs from that prescribed by Canadian GAAP. Adopting the provisions of FAS 123R is not expected to have a material impact on the U.S. GAAP financial statements.

The following oil and gas information is provided in accordance with the U.S. Financial Accounting Standards Board Statement No. 69 "Disclosure About Oil and Gas Producing Activities". The Trust follows the full cost method of accounting. The following information is unaudited.

Unaudited Supplementary Information

(a) Capitalized Costs

The aggregate amounts of costs capitalized for gas and oil producing activities, and related aggregate amounts of accumulated depreciation, depletion and amortization at December 31, 2005 and 2004 as follows:

	2005	2004
Capitalized costs of:		
Proved properties being amortized	$ 534,937	$ 181,778
Undeveloped land not being amortized	71,666	3,430
Total capitalized costs	606,603	185,208
Less accumulated depletion, depreciation, and amortization	(177,925)	(67,268)
Net Capitalized costs	$ 428,678	$ 117,940

The following costs were incurred in oil and gas-producing activities during the years ended December 31, 2005 and 2004:

	2005	2004
Property acquisition costs: (1)		
Proved properties	$ 271,191	$ 45,265
Unproved properties	127,103	8,062
Exploration costs	–	4,289
Development costs	23,101	8,800
Total costs incurred	$ 421,395	$ 66,416

(1) Includes costs related to corporate acquisitions.

As at December 31, 2005 and 2004 and for the years there ended (Expressed in Canadian Dollars)
(Tabular amounts are stated in thousands of dollars except unit and per unit information)

(b) Reserve Quantity Information

Estimated net quantities of proved gas and oil (including condensate) reserves at December 31, 2005 and 2004, and changes in the reserves during those years, are shown in the following two tables. Reserve volumes are reported on net of royalties basis.

	2005 Net	2004 Net
Proved developed and undeveloped reserves – Oil and NGL (mboe)		
At January 1	5,170	4,457
Changes in reserves:		
Extensions, discoveries and other additions	26	139
Revisions of previous estimates	729	(96)
Production	(1,550)	(1,672)
Purchases of oil and NGL's in place	968	2,363
Sales of oil in place	–	(21)
At December 31	5,343	5,170
Proved developed reserves – Oil and NGL		
At January 1	5,069	4,457
At December 31	5,197	5,069

Proved developed and undeveloped reserves – Gas (mmcf)		
At January 1	5,502	4,464
Changes in reserves:		
Extensions, discoveries and other additions	78	150
Revisions of previous estimates	(3,324)	(1,002)
Production	(3,738)	(1,932)
Purchases of gas in place	36,180	3,822
Sales of gas in place	–	–
At December 31	34,698	5,502
Proved developed reserves - Gas		
At January 1	5,454	4,464
At December 31	31,266	5,454

Included in these proven reserves are gas volumes of 1,600 mmcf which are located in the U.S. cost center.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As at December 31, 2005 and 2004 and for the years there ended (Expressed in Canadian Dollars)
(Tabular amounts are stated in thousands of dollars except unit and per unit information)

(c) Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

The following tabulation has been prepared in accordance with the FASB's rules for disclosure of a standardized measure of discounted future net cash flows relating to proved gas and oil reserve quantities owned by the Trust.

	2005	2004
Future cash inflows [1]	$ 801,333	$ 260,750
Less:		
Future development costs	(7,184)	(677)
Future production, royalty and abandonment costs	(330,808)	(145,563)
Future income tax expense	(80,056)	(18,272)
Future cash flows	383,285	96,238
Less annual discount (10% a year)	(96,508)	(15,118)
Standardized measure of discounted future net cash flows	$ 286,777	$ 81,120

[1] Amounts exclude the effect of derivative instruments designated as hedges of future sales of production at year end.

In the foregoing determination of future cash inflows, sales prices for gas and oil were based on contractual arrangements or market prices at year-end. Future costs of developing and producing the proved gas and oil reserves reported at the end of each year shown were based on costs determined at each such year end, assuming the continuation of existing economic conditions. Future income taxes were computed by applying the appropriate year-end or future statutory tax rate to future pretax net cash flows, less the tax basis of the properties involved, and giving effect to tax deductions, permanent differences and tax credits.

It is not intended that the FASB's standardized measure of discounted future net cash flows represent the fair market value of the Trust's proved reserves. The Trust cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules that are inherently imprecise and subject to revision, and the 10 percent discount rate is arbitrary. In addition, costs and prices as of the measurement date are used in the determinations, and no value may be assigned to probable or possible reserves.

The following tabulation is a summary of changes between the total standardized measure of discounted future net cash flows at the beginning and end of each year.

	2005	2004
Standardized measure of discounted future net cash flows at January 1	$ 81,120	$ 90,559
Changes in the year resulting from:		
Sales and transfers of oil and gas produced during the year, net of production costs	(89,044)	(60,274)
Net change in sales and transfer prices, net of production costs	107,194	7,140
Extensions, discoveries and other additions, net of future production and development cost	1,024	4,244
Change in estimated future development costs	(21,869)	488
Development costs incurred during the year	23,101	
Revisions of previous quantity estimates	5,576	314
Accretion of discount	8,112	9,056
Net change in income taxes	(39,068)	(2,174)
Purchases of proved reserves in place [1]	210,631	32,179
Sales of proved reserves in place	–	(412)
Standardized measure of discounted future net cash flows at December 31	$ 286,777	$ 81,120

[1] Exludes the value associated with undeveloped properties and land.

ANNUAL GENERAL AND SPECIAL MEETING

The Annual General and Special Meeting of the unitholders will be held on May 18, 2006 at 3:00pm in the Kensington AB Room at the Calgary Marriott Hotel, 110 9th Avenue SE, Calgary, AB T2G 5A6.

Unitholders are encouraged to attend and those unable to do so are requested to complete and return the proxy form to the company's registrar and transfer agent, Olympia Trust Company.

Abbreviations

bbl	barrel
mbbl	thousand barrels
bbls/day	barrels per day
mcf	thousand cubic feet
mmcf	million cubic feet
mcf/day	thousand cubic feet per day
mmcf/day	million cubic feet per day
bcf	billion cubic feet
boe	barrels of oil equivalent (6 mcf equivalent to 1 bbl)
boe/day	barrels of oil equivalent per day (6 mcf equivalent to 1 bbl)
mboe	thousand barrels of oil equivalent
NGL	natural gas liquids
GJ	gigajoule
GJ/day	gigajoule per day
MMBTU	million British Thermal Units

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Chartered Accountants
Calgary, AB

Solicitors

McCarthy Tetrault
Calgary, AB

Gowling Lafleur
Henderson LLP
Calgary, AB

Reservoir Engineers

McDaniel & Associates
Consultants Ltd.
Calgary, AB

Sproule Associates Inc.
Denver, CO

Transfer agent

Olympia Trust Company
Calgary, AB

Stock exchange listings

NYSE (symbol: ENT)
TSX (symbol: ENT.UN)

Directors

E. Keith Conrad
R.H. (Joseph) Vidal
Norman W. Wallace*
H.S. (Scobey) Hartley*
William E. Sliney*

**Member, Audit Committee*

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