# Bonterra
Energy Income Trust

2003 ANNUAL REPORT

Bonterra
Energy Income Trust

## Trust Profile

Bonterra Energy Income Trust (TSX symbol – BNE.UN) is an energy income trust that develops and produces oil and natural gas in the Provinces of Alberta and Saskatchewan.

The Trust's business strategy is to strive to maximize Unitholder's value by applying long-term growth objectives. The Trust's primary objective is to combine its oil and gas production technical strengths with planned business strategies to generate above average results and returns for our Unitholders.

## Contents



## Notice of Annual General Meeting

The Annual General Meeting of Unitholders will be held on Wednesday, June 16, 2004, in the Lakeview Endrooms at the Westin Hotel, 320 Fourth Avenue S.W., Calgary, Alberta, at 11:00 a.m. (Calgary time).

## Highlights

| | 2003 | 2002 |
|---|---|---|
| **FINANCIAL** ($000, except $ per unit) | | |
| Revenue - oil and gas (net of royalties) | **$ 38,377** | $ 36,424 |
| Distributions per Unit | **1.55** | 1.43 |
| Cash Flow from Operations [1] | **22,107** | 19,458 |
| Per Unit Fully Diluted | **1.63** | 1.50 |
| Net Earnings | **14,039** | 12,474 |
| Per Unit Fully Diluted | **1.04** | 0.96 |
| Capital Expenditures and Acquisitions | **5,387** | 52,751 |
| Outstanding Debt | **21,216** | 18,357 |
| Unitholders' Equity | **36,684** | 41,892 |
| Units Outstanding (000's) | **13,521** | 13,368 |
| **OPERATIONS** | | |
| Oil and Liquids *(barrels per day)* | **2,384** | 2,464 |
| Average Price *($ per barrel)* | **$ 39.65** | $ 37.35 |
| Natural Gas *(MCF per day)* | **4,403** | 4,287 |
| Average Price *($ per MCF)* | **$ 5.45** | $ 4.10 |
| Total Barrels per Day (*BOE per day*) [2] | **3,118** | 3,179 |
| **RESERVES** | | |
| Oil and Liquids *(barrels in 000's)* | | |
| Proven Developed Producing *(Gross)* [3] | **11,032** | 11,830 |
| Proven plus Probable *(Gross)* | **13,357** | 12,249 |
| Natural Gas *(MCF in 000's)* | | |
| Proven Developed Producing *(Gross)* | **15,978** | 15,278 |
| Proven plus Probable *(Gross)* | **19,031** | 15,898 |
| Life Index (Oil, liquids and natural gas @ 6:1) | | |
| Proven Developed Producing | **11.1** | 12.3 |
| Proven and Probable | **13.4** | 12.8 |
| Reserves in BOE's per Outstanding Unit | | |
| Proven Developed Producing | **1.01** | 1.08 |
| Proven and Probable | **1.22** | 1.11 |

**Note 1** Cash flow from operations is a non-GAAP measure that represents cash generated from operating activities before changes in non-cash working capital. Cash flow from operations may not be comparable to similar measures used by other organizations.

**Note 2** BOE's are calculated using a conversion ratio of 6 MCF to 1 barrel of oil. The conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead and as such may be misleading if used in isolation.

**Note 3** Gross reserves relate to the Trusts ownership of reserves before royalty interests.

# Report to Unitholders

Bonterra Energy Income Trust ("Bonterra") is pleased to report its operational and financial results for the year. The Trust had a successful growth year and its annual distributions and capital appreciation resulted in a rate of return to Unitholders of 78 (2002 – 59) percent, far exceeding the return of most trusts and corporations.

## Operations

Bonterra's production is ideally suited for a trust. Approximately 75 percent of its production is light, sweet gravity crude and liquids, and the remaining 25 percent natural gas is sweet long-life production. The life index for the Trust's proven developed producing reserves is approximately 11.1 years, which is significantly higher than most other trusts. Bonterra's life index including all categories of proven and probable reserves is approximately 13.4 years. It should be noted that the Trust has included only a nominal amount (less than .5 BCF) of probable reserves for undrilled shallow gas in the Pembina area.

The long life index allows the Trust to distribute a higher percentage of its cash flow to Unitholders rather than using it for capital expenditures to maintain production volumes. Bonterra's annual actual decline rate from existing properties is approximately eight percent before capital expenditures.

Production volumes for 2003 averaged 3,118 barrels of oil equivalent (BOE's) per day compared to 3,179 BOE's per day in 2002. The December 31, 2003 exit production was approximately 3,250 BOE's per day. Production was lower in 2003 due to the timing of the drilling as well as minor operational problems. Production volumes should improve in 2004. This is supported by the increase in reserves during 2003.

## Financial

Bonterra's distribution for 2003 was $1.55 compared to $1.43 for 2002. The taxable portion in 2003 was 68.92 (2002 – 69.82) percent and 31.08 (2002 – 30.18) percent is a return of capital.

Revenue (net of royalties) from commodity sales was $38,377,000 in 2003 compared to $36,424,000 for the preceding year. Commodity prices were $39.65 (2002 - $37.35) per barrel of oil and natural gas liquids, and $5.45 (2002 - $4.10) per MCF for natural gas.

At year-end Bonterra's debt was approximately $21,216,000 (2002 - $18,357,000), which is less than one years cash flow on an annualized basis. This level of debt falls within the Trust's objective of debt being less than one year's cash flow.

## Outlook

The objectives for the Trust are to increase its production volumes and reserves in the future by developing its existing properties and by acquiring additional production. During the first quarter of 2004, Bonterra drilled 10 gross shallow gas wells in the Pembina area. Eight of these wells have been or will be completed in the Edmonton zone and two will be completed as coal-bed methane wells. The Trust has just recently received approval from the Alberta regulators to down space the spacing units for coal-bed methane wells. The approval will allow Bonterra to drill more than one well per section of land. This will allow Bonterra to commence its planned coal-bed drill program during the second and third quarters of 2004. Bonterra will also continue its Edmonton sand development drilling during the second quarter. The Trust continues to look for strategic acquisitions that compliment our portfolio and would provide a benefit to Unitholders over the long term.

The Trust is optimistic with regard to its drill programs and its ability to continue to provide high returns and additional appreciation of its unit price. It should be noted that since Bonterra Energy Corp. (predecessor to the Trust) was incorporated and listed publicly in mid 1998, for every $100 invested at that time, a Unitholder that held continuously from that date to December 31, 2003 would have received distributions of $862.49 plus unit appreciation of $3,329.38.

The Board of Directors of the operating company and management wish to thank the Unitholders for their continued loyal support and advice and the staff for the significant contributions made by them.

The directors and management also wish to take this opportunity to thank Mr. Murray Pyke, director, and Mr. Steve Safronovich, senior consultant, who both retired during the year, for their many years of service. Their contributions have been greatly appreciated.

Submitted on behalf of the Board of Directors,

George F. Fink
President, CEO and Director

## Review of Operations

### Reserves

The Trust engaged the services of Sproule Associates Limited to prepare a reserve evaluation with an effective date of January 1, 2004. The reserves are located in the Provinces of Alberta and Saskatchewan. The majority of the Trust's production is comprised of light sweet crude, which results in higher oil prices, and better marketing opportunities. The Trust's main oil producing areas are located in the Pembina area of Alberta and the Dodsland area of Saskatchewan. The gross reserve figure in the following charts represents the Trust's ownership interest before royalties and the net figure is after deductions for royalties.

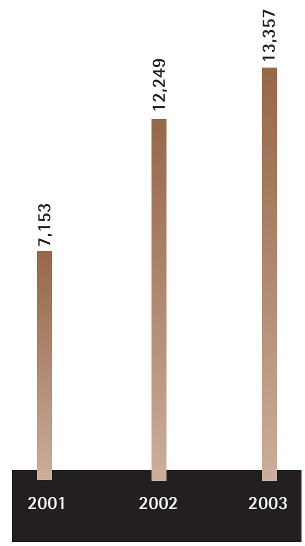
### Summary of Oil and Gas Reserves as of December 31, 2003 (Forecast Prices and Costs)

| | RESERVES | | | | | |
|---|---|---|---|---|---|---|
| | Light and Medium Oil | | Natural Gas | | Natural Gas Liquids | |
| Reserve Category | Gross (Mbbl) | Net (Mbbl) | Gross (MMcf) | Net (MMcf) | Gross (Mbbl) | Net (Mbbl) |
| Proved | | | | | | |
| Developed Producing | 10,285 | 9,842 | 15,978 | 11,896 | 747 | 528 |
| Developed Non-Producing | - | - | 244 | 218 | - | - |
| Undeveloped | 333 | 307 | 412 | 318 | 22 | 15 |
| Total Proved | 10,618 | 10,149 | 16,634 | 12,432 | 769 | 543 |
| Probable | 1,864 | 1,785 | 2,397 | 1,849 | 106 | 78 |
| Total Proved Plus Probable | 12,482 | 11,934 | 19,031 | 14,281 | 875 | 621 |

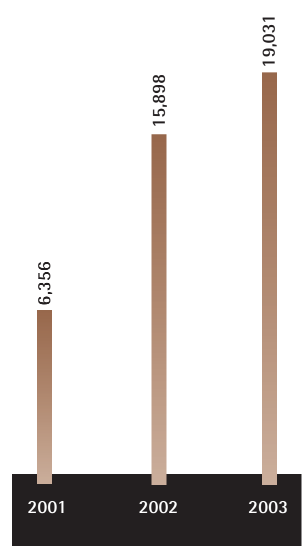
### Reconciliation of Trust Gross Reserves by Principal Product Type (Forecast Prices and Costs)

| | Light and Medium Oil | | | Natural Gas | | |
|---|---|---|---|---|---|---|
| | Gross Proved (Mbbl) | Gross Probable (Mbbl) | Gross Proved Plus Probable (Mbbl) | Gross Proved (MMcf) | Gross Probable (MMcf) | Gross Proved Plus Probable (MMcf) |
| December 31, 2002 | 11,051 | 388 | 11,439 | 15,278 | 620 | 15,898 |
| Discoveries | 530 | 96 | 626 | 1,391 | 320 | 1,711 |
| Technical revisions | (156) | 1,380 | 1,224 | 1,572 | 1,457 | 3,029 |
| Production | (807) | - | (807) | (1,607) | - | (1,607) |
| December 31, 2003 | 10,618 | 1,864 | 12,482 | 16,634 | 2,397 | 19,031 |

**Oil and NGL Reserves Gross Proven and Probable (Mbbl's)**




**Natural Gas Reserves Gross Proven and Probable (MMcf)**



### Summary of Net Present Values of Future Net Revenue as at December 31, 2003 (Forecast Prices and Costs)

| (000's) Reserve Category | NET PRESENT VALUE OF FUTURE NET REVENUE Before and After Income Taxes Discounted at (%/year) 0 | 5 | 10 | 15 | 20 |
|---|---|---|---|---|---|
| Proved | | | | | |
| Developed Producing | 215,663 | 143,830 | 109,689 | 89,915 | 77,025 |
| Developed Non-Producing | 731 | 636 | 561 | 503 | 455 |
| Undeveloped | 5,254 | 3,146 | 1,873 | 1,062 | 519 |
| Total Proved | 221,648 | 147,612 | 112,123 | 91,480 | 77,999 |
| Probable | 47,207 | 20,300 | 11,158 | 7,180 | 5,103 |
| Total Proved Plus Probable | 268,855 | 167,912 | 123,281 | 98,660 | 83,102 |

Commodity prices used in the above calculations of reserves are as follows:

| Year | Edmonton Par Price (Cdn $ per barrel) | Alberta Index Plantgate (Cdn $ per MCF) | Propane (Cdn $ per barrel) | Butane (Cdn $ per barrel) | Pentane (Cdn $ per barrel) |
|---|---|---|---|---|---|
| 2004 | 37.99 | 5.81 | 28.04 | 31.15 | 38.91 |
| 2005 | 34.24 | 5.15 | 22.56 | 25.52 | 35.07 |
| 2006 | 32.87 | 4.59 | 20.58 | 23.28 | 33.67 |
| 2007 | 33.37 | 4.71 | 20.89 | 23.63 | 34.17 |
| 2008 | 33.87 | 4.80 | 21.20 | 23.98 | 34.69 |
| 2009 | 34.38 | 4.88 | 21.52 | 24.34 | 35.21 |
| 2010 | 34.90 | 4.98 | 21.85 | 24.71 | 35.74 |
| 2011 | 35.43 | 5.05 | 22.18 | 25.08 | 36.28 |
| 2012 | 35.96 | 5.14 | 22.51 | 25.46 | 36.83 |
| 2013 | 36.50 | 5.24 | 22.85 | 25.85 | 37.38 |
| 2014 | 37.05 | 5.34 | 23.20 | 26.24 | 37.95 |
| 2015 | 37.61 | 5.43 | 23.55 | 26.63 | 38.52 |

Crude oil, natural gas and liquid prices escalate at 1.5% per year thereafter.

### Production

The following table provides a summary of production volumes from our main producing areas.

| | 2003 Oil and NGL (Bbls/day) | 2003 Natural Gas (MCF/day) | 2002 Oil and NGL (Bbls/day) | 2002 Natural Gas (MCF/day) |
|---|---|---|---|---|
| Pembina, Alberta | 1,733 | 3,502 | 1,812 | 2,972 |
| Dodsland, Saskatchewan | 399 | 268 | 474 | 305 |
| Pinto, Saskatchewan | 50 | 53 | 51 | 50 |
| Redwater, Alberta | 46 | 72 | 43 | 95 |
| Midale, Saskatchewan | 42 | 15 | 45 | 20 |
| Other | 114 | 493 | 39 | 845 |
| | 2,384 | 4,403 | 2,464 | 4,287 |

## Land Holdings

The Trust's holdings of petroleum and natural gas leases and rights are as follows:

| | 2003 Gross Acres | 2003 Net Acres | 2002 Gross Acres | 2002 Net Acres |
|---|---|---|---|---|
| Alberta | 113,057 | 66,519 | 111,200 | 64,020 |
| Saskatchewan | 32,584 | 19,524 | 32,584 | 19,524 |
| | 145,641 | 86,043 | 143,784 | 83,544 |

## Petroleum and Natural Gas Capital Expenditures

The following table summarizes petroleum and natural gas capital expenditures incurred by the Trust on acquisitions, land, seismic, exploration and development drilling and production facilities for the years ended December 31:

| | 2003 | 2002 |
|---|---|---|
| Comstate Resources Income Trust acquisition | $ – | $47,697,000 |
| Other acquisitions | **32,000** | 2,333,000 |
| Exploration and development costs | **5,226,000** | 2,239,000 |
| Pipeline projects | **30,000** | 481,000 |
| Seismic | **3,000** | 1,000 |
| Land costs | **96,000** | – |
| Net petroleum and natural gas capital expenditures | **$5,387,000** | $52,751,000 |

## Drilling History

The following table summarizes the Trust's gross and net drilling activity and success:

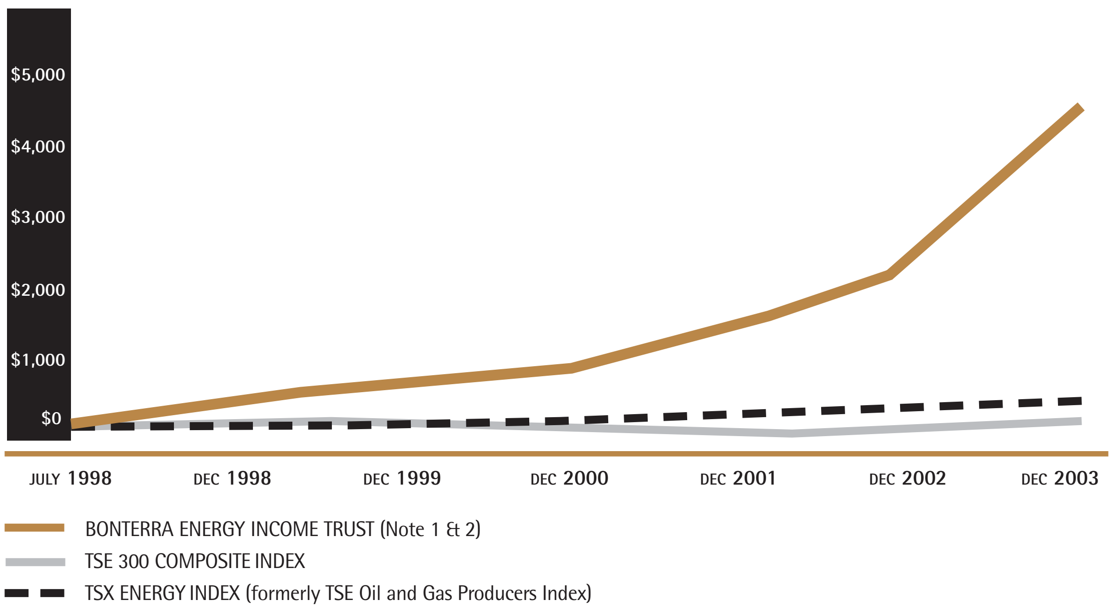
| 2003 | Development Gross | Development Net | Exploratory Gross | Exploratory Net | Total Gross | Total Net |
|---|---|---|---|---|---|---|
| Crude Oil | 31 | 3.27 | – | – | 31 | 3.27 |
| Natural Gas | 3 | 3.00 | 6 | 5.83 | 9 | 8.83 |
| Dry | – | – | – | – | – | – |
| Total | 34 | 6.27 | 6 | 5.83 | 40 | 12.10 |
| Success rate | 100% | 100% | 100% | 100% | 100% | 100% |

| 2002 | Development Gross | Development Net | Exploratory Gross | Exploratory Net | Total Gross | Total Net |
|---|---|---|---|---|---|---|
| Crude Oil | 1 | .13 | – | – | 1 | 0.13 |
| Natural Gas | 1 | 1.00 | 9 | 7.25 | 10 | 8.25 |
| Dry | – | – | – | – | – | – |
| Total | 2 | 1.13 | 9 | 7.25 | 11 | 8.38 |
| Success rate | 100% | 100% | 100% | 100% | 100% | 100% |

| | 2001 | | | | | |
|---|---|---|---|---|---|---|
| | Development | | Exploratory | | Total | |
| | Gross | Net | Gross | Net | Gross | Net |
| Crude Oil | 2 | 2.00 | – | – | 2 | 2.00 |
| Natural Gas | 1 | .97 | 7 | 6 | 8 | 6.97 |
| Dry | – | – | – | – | – | – |
| Total | 3 | 2.97 | 7 | 6 | 10 | 8.97 |
| Success rate | 100% | 100% | 100% | 100% | 100% | 100% |

## Market Performance

**Cumulative Total Return on $100 Investment**




**Note 1** Includes the results of Bonterra Energy Corp. prior to July 1, 2001

**Note 2** Includes distributions of $3.78 since becoming a trust

## Property Discussions

Bonterra has an excellent asset base consisting of long life, low risk and predictable reserves with upside and management that has proven it can manage these high quality assets to generate long-term value. Our producing properties are located in the Pembina area of Alberta, the East Central area of Alberta, the Dodsland area in southwest Saskatchewan, and the southeast area of Saskatchewan. Bonterra continues to acquire exploration lands in the Pembina area of Alberta, is pursuing other drilling opportunities in Alberta and Saskatchewan and reviews and assesses producing and non-producing properties for acquisitions on an ongoing basis in various areas in Western Canada.

### Pembina Area, West Central Alberta

The Pembina field is the largest conventional oil field in Canada and our most significant producing property. Bonterra's production is predominately predictable, long life, low decline and high quality light oil from the Cardium formation that is located at a depth of approximately 1,550 meters. Bonterra operates approximately 85 percent of its production in this large core area which allows for significant operating efficiencies. The property contains approximately 340 gross (292 net) operated producing wells with an 86 percent average working interest and 137 gross (23.7 net) non-operated producing wells with an approximate 17 percent average working interest.

The Trust's large land holdings and strong infrastructure position provides a strong base to exploit a range of low risk development and exploration opportunities. Even though the Pembina area is considered a mature field it is proving to be a significant area for multi-zone oil and natural gas exploration. The Trust has managed to replace produced reserves in the area through drilling as well as through key acquisitions.

Bonterra is also producing from the Belly River formation. The Belly River produces high quality light sweet oil from a depth of approximately 1,100 meters. There is potential to increase production from the Cardium and Belly River formations through infill drilling in select areas of the field. This program was initiated in non-operated properties in 2003.

Bonterra has been able to increase natural gas production and reserves by drilling multi-zone shallow gas wells into the Edmonton and Paskapoo formations. The Trust is targeting several productive sands that range in depth from 275 to 750 meters. Bonterra will continue to build on its previous exploration success in the area and develop these low cost shallow natural gas reserves.

Bonterra has been assessing production of coal-bed methane (CBM) in this area for a period of two years with encouraging initial results. This assessment has resulted in proceeding with a program for 2004 to re-enter existing wells or drill new wells for approximately 25 locations. Bonterra has extensive prospective land holdings near existing operated infrastructure in the area. CBM has the potential to add significant low risk production and reserves and the Trust is aggressively pursuing this opportunity.

### Dodsland Area, Southwest Saskatchewan

The Dodsland properties produce light sweet gravity oil and solution gas from the Viking formation at a depth of approximately 700 meters. Bonterra now operates 373 gross (333.4 net) wells with an average working interest of 89 percent.

This is low rate stable production so cost control and hedge programs are important focuses of our operating strategy in this area. The Trust is continually reviewing different operating practices and improved technology that may improve the profitability of the property. Bonterra does not have an abandonment or reclamation liability for this property because under terms of an agreement Bonterra has an option to transfer uneconomic wells to the previous owner of the property.

### Southeast Saskatchewan

The southeast properties produce slightly sour high gravity oil and solution gas from the Midale formation. The Trust has an average working interest of approximately 98 percent of its properties in the area. Bonterra continues to evaluate this area to determine if further optimization programs may increase overall profitability of the properties.

### Other

Bonterra has varying interests in other producing and non-producing properties in various other areas of Alberta and Saskatchewan. Most of these properties are long-term producers and may provide opportunities for increased interests in the future.

## Management's Discussion and Analysis

This report dated March 31, 2004 is a review of the operations, current financial position and outlook for the Trust and should be read in conjunction with the audited financial statements for the fiscal year ended December 31, 2003, together with the notes related thereto.

| Annual Comparisons | 2003 | 2002 | 2001 |
|---|---|---|---|
| **FINANCIAL** ($000, except $ per unit) | | | |
| Revenue - oil and gas (net of royalties) | $ 38,377 | $ 36,424 | $ 11,257 |
| Cash Flow from Operations [1] | 22,107 | 19,458 | 6,446 |
| Per Unit Diluted | 1.63 | 1.50 | 0.74 |
| Net Earnings | 14,039 | 12,474 | 5,366 |
| Per Unit Diluted | 1.04 | 0.96 | 0.62 |
| Cash Distributions per Unit | 1.55 | 1.43 | 0.80 |
| Capital Expenditures and Acquisitions | 5,387 | 52,751 | 1,329 |
| Total Assets | 74,554 | 76,417 | 26,152 |
| Outstanding Loans | 21,216 | 18,357 | 7,890 |
| Unitholders' Equity | 36,684 | 41,892 | 11,388 |
| Operations | | | |
| Oil and Liquids *(barrels per day)* | 2,384 | 2,464 | 1,531 |
| Natural Gas *(MCF per day)* | 4,403 | 4,287 | 1,408 |

[1] Cash flow from operations is a non-GAAP measure that represents cash generated from operating activities before changes in non-cash working capital. Cash flow from operations may not be comparable to similar measures used by other organizations.

| Quarterly Comparisons | 2003 4th | 2003 3rd | 2003 2nd | 2003 1st |
|---|---|---|---|---|
| **FINANCIAL** ($000, except $ per unit) | | | | |
| Revenue - oil and gas (net of royalties) | $ 9,408 | $ 9,315 | $ 9,108 | $10,246 |
| Cash Flow from Operations | 5,868 | 5,114 | 4,721 | 6,404 |
| Per Unit Diluted | 0.43 | 0.38 | 0.35 | 0.48 |
| Net Earnings | 3,608 | 3,062 | 2,948 | 4,420 |
| Per Unit Diluted | 0.26 | 0.23 | 0.22 | 0.33 |
| Cash Distributions | 0.36 | 0.38 | 0.40 | 0.41 |
| Capital Expenditures and Acquisitions | 2,361 | 1,453 | 1,055 | 518 |
| Total Assets | 74,554 | 73,891 | 74,492 | 75,778 |
| Outstanding Loans | 21,216 | 21,350 | 20,960 | 18,792 |
| Unitholders' Equity | 36,684 | 38,018 | 40,170 | 42,703 |
| Operations | | | | |
| Oil and Liquids *(barrels per day)* | 2,429 | 2,325 | 2,382 | 2,400 |
| Natural Gas *(MCF per day)* | 4,272 | 4,386 | 4,297 | 4,661 |

## Quarterly Comparisons

| | 2002 4th | 3rd | 2nd | 1st |
|---|---|---|---|---|
| **FINANCIAL** ($000, except $ per unit) | | | | |
| Revenue - oil and gas (net of royalties) | $ 9,781 | $10,035 | $ 9,128 | $ 7,480 |
| Cash Flow from Operations | 5,515 | 5,157 | 4,835 | 3,951 |
| Per Unit Diluted | 0.42 | 0.40 | 0.37 | 0.31 |
| Net Earnings | 4,043 | 2,716 | 3,261 | 2,454 |
| Per Unit Diluted | 0.31 | 0.21 | 0.25 | 0.19 |
| Cash Distributions | 0.35 | 0.37 | 0.38 | 0.33 |
| Capital Expenditures and Acquisitions | 808 | 2,673 | 414 | 48,856 |
| Total Assets | 76,417 | 77,408 | 76,090 | 77,087 |
| Outstanding Loans | 18,357 | 18,226 | 16,756 | 16,270 |
| Unitholders' Equity | 41,892 | 44,266 | 46,362 | 48,181 |
| Operations | | | | |
| Oil and Liquids *(barrels per day)* | 2,571 | 2,600 | 2,341 | 2,175 |
| Natural Gas *(MCF per day)* | 4,605 | 4,953 | 3,787 | 3,159 |

### Production

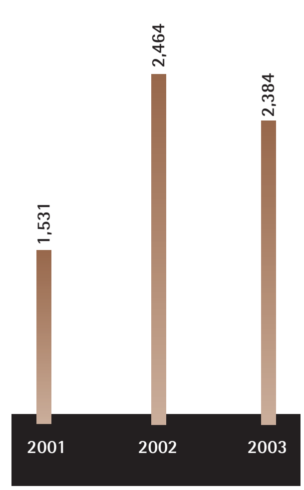
The Trust's 2003 average production of oil and natural gas liquids was 2,384 (2002 – 2,464) barrels per day and natural gas production in 2003 averaged 4,403 (2002 – 4,287) MCF per day. Oil production declined by approximately three percent while gas production increased by approximately three percent. Part of the reduced production was a major scheduled gas plant turnaround in the Carnwood area of Alberta which resulted in the Trust shutting in several of its oil and natural gas wells for a significant portion of September. This turnaround had an impact on our annual production figure of over 12 barrels per day of oil plus associated gas production of a similar amount.

The Trust's overall annual decline rate is approximately eight percent which was mostly offset with its 2003 drill program. Most of the drilling was performed in the last four months of 2003 with the majority of crude oil production commencing in November and most natural gas production commencing in quarter one 2004. Crude oil development drilling was done on two of the Trust's non-operated interests with net production gains in November and December of approximately 100 barrels per day. These wells have a fairly high decline rate but production is anticipated to flatten out at about 20 to 30 barrels per day net to the Trust.

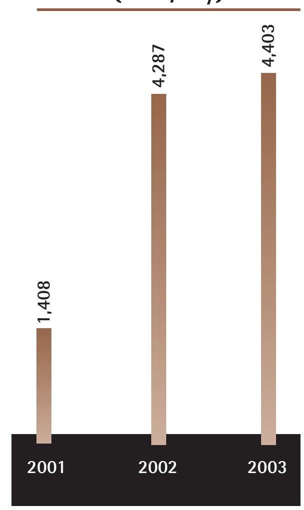
The Trust tied-in three gas wells in January 2004 that were drilled and completed in late 2003. These shallow gas wells are currently producing approximately 400 MCF per day net to the Trust. Production from these wells as well as from our January to March 2004 drilling program should result in an increase in excess of 1,000 MCF per day compared to our fourth quarter 2003 production.

The Trust has been given approval by the Alberta Energy and Utilities Board to reduce the drill spacing unit size for CBM in the Pembina area of Alberta. This approval will assist in increasing the recovery of CBM as well as increase the number of 100 percent owned wells the Trust can drill. The Trust has plans for drilling and or re-completion of approximately 25 CBM wells in 2004.

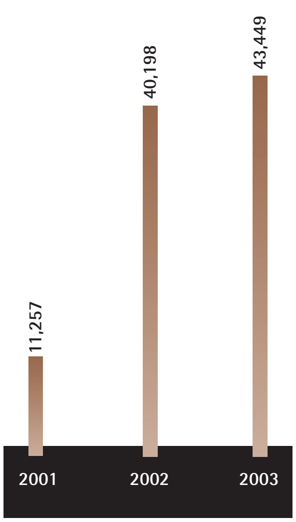
**Oil and NGL Production (Bbls/day)**




**Natural Gas Production (MCF/day)**



Gross Revenues
($000)




## Revenue

Gross revenue from petroleum and natural gas sales was $43,449,000 (2002 - $40,198,000). The average price received for crude oil and natural gas liquids including hedging, was $39.65 (2002 - $37.35) per barrel and $5.45 (2002 - $4.10) per MCF of natural gas. Gross revenue has been reduced by $3,150,000 due to lower prices received as a result of price hedging. Over 95 percent of the Trust's crude oil production consists of light sweet crude with nominal quality and transportation adjustments. Natural gas production consists primarily of dry sweet natural gas.

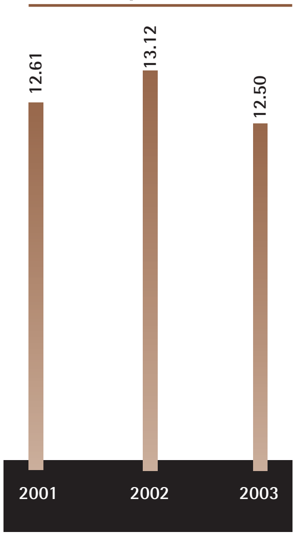
The Trust will continue to hedge a small portion of future production (see Business Prospects, Risks, and Outlooks) to assist in managing its cash flow. The Trust continues to follow the policy of protecting high cost production with hedges that provide a significant level of profitability and also to provide for a reasonable amount of cash flow protection for development projects. The Trust will continue to maintain a policy of not hedging more than 50 percent of production, but factually rarely hedges to that level.

## Royalties

Royalties paid by the Trust consist primarily of Crown royalties paid to the Provinces of Alberta and Saskatchewan. During 2003 the Trust paid $3,968,000 (2002 - $2,995,000) in Crown royalties and $1,104,000 (2002 - $778,000) in freehold royalties, gross overriding royalties and net carried interests. The majority of the Trust's wells are low productivity wells and therefore have low Crown royalty rates. The Trust's average Crown royalty rate is approximately eight percent (2002 – seven percent) and approximately two percent (2002 – two percent) for other royalties before hedging adjustments. The increase in Crown royalty percentage is due to the increase in natural gas production which has a higher Crown royalty rate than crude oil production. The Trust is eligible for Alberta Crown Royalty rebates for Alberta production from all wells that it drilled on Crown lands and from a small amount of purchased wells.

## Production Costs

Production Costs
($ per BOE)




Production costs totalled $14,227,000 in 2003 compared to $15,226,000 in 2002. On a barrel of oil equivalent (BOE) basis 2003 operating costs were $12.50 compared to $13.12 for 2002. BOE's are calculated using a conversion ratio of 6 MCF to 1 barrel of oil. The conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead and as such may be misleading if used in isolation.

As discussed above, the Trust's production comes primarily from low productivity wells. These wells generally result in higher operating costs on a per unit-of-production basis as costs such as municipal taxes, surface lease, power and personnel costs are not variable with production volumes.

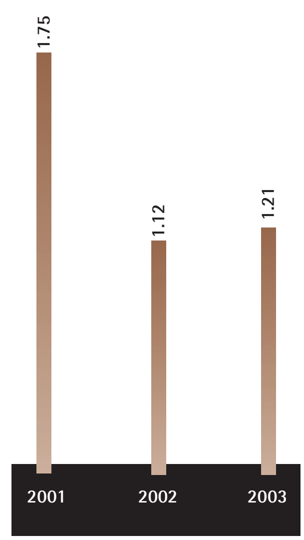
The Trust is currently examining means of reducing operating costs. Operating costs in the $12 to $13 per BOE range are expected. As the Trust develops its shallow natural gas potential, the average costs per BOE will decline. The high operating costs for the Trust are substantially offset by low royalty rates of approximately 10 percent, which is much lower than industry average for conventional production and results in high cash net backs on a combined basis despite higher than average operating costs.

## General and Administrative Expense

General and administrative expenses were $1,372,000 in 2003 compared to $1,298,000 in 2002. On a BOE basis, general and administrative expenses in 2003 averaged $1.21 compared to $1.12 per BOE in 2002. Average general and administrative costs in the range of $1.20 place the Trust in the lower third of average costs for Trusts.

The Trust is managed internally. In addition, the Trust provides administrative services to two other public companies that share common directors and management. Fees for these services are deducted from the Trusts general and administrative expenses. During 2003, the Trust received a management fee from Novitas Energy Ltd. (Novitas) for management services of $10,000 (2002 - $5,000) per month plus five percent of before tax income. Total receipts during 2003 were $120,000 (2002 - $68,000). Novitas also paid administrative fees on a per well basis to the Trust for the administration of its oil and gas properties. Total amount paid during 2003 was $148,000 (2002 - $128,500). The Trust received a management fee from Comaplex Minerals Corp. (Comaplex) of $210,000 (2002 - $110,000) for management services and office administration.

**General and Administrative ($ per BOE)**




## Interest Expense

Interest expense for the 2003 fiscal year for the Trust was $894,000 (2002 - $671,000). Interest rate charges during the period on the outstanding debt averaged approximately 4.25 (2002 - 4) percent. The Trust maintained an average outstanding debt balance of approximately $20,600,000 (2002 - $16,500,000). Total debt as a percentage of annual cash flow continues to average less than one year. The Trust believes this is an appropriate level to allow it to take advantage in the future of either acquisition opportunities or to provide flexibility to develop its CBM and shallow gas potential without requiring the issuance of trust units.

The Trust's banking arrangement allows it to use Bankers Acceptances (BA's) as part of its loan facility. Interest charges on BA's are generally one third percent lower than that charged on the general loan account. The Trust also has a $3,750,000 (2002 - $8,000,000) balance owing to Comaplex as of December 31, 2003. The loan carries an interest rate of Royal Bank of Canada prime less three quarters of a percent. The loan arrangements assist in reducing overall interest expense.

## Depletion, Depreciation, Future Site Restoration and Dry Hole Costs

The Trust follows the successful efforts method of accounting for petroleum and natural gas exploration and development costs. Under this method, the costs associated with dry holes are charged to operations. For intangible capital costs that result in the addition of reserves, the Trust depletes its oil and natural gas intangible assets using the unit-of-production basis by field. The Trust believes that the successful efforts method of accounting provides a more accurate cost of the producing properties than the alternative measure of full cost accounting.

For tangible assets such as well equipment, a life span of ten years is estimated and the related tangible costs are depreciated at one-tenth of original cost per year. The use of a ten year life span instead of calculating depreciation over the life of reserves was determined to be more representative of actual costs of tangible property. Given the Trusts long production life, wells generally require replacement of tangible assets more than once during their life time. Most of the Trusts wells have been producing since the 1960's and are expected to continue to produce for at least another twenty years.

Provisions are made for abandonment and future site restoration based on management's estimation of abandonment requirements using current costs and amortized on a unit-of-production basis by field. Effective January 1, 2004, the Trust is required to change how it reports its future site restoration. Under the new accounting rules a discounted estimate of the total abandonment and site reclamation costs using escalating cost assumptions is required to be recorded with an offset to the cost of the related intangible assets. The adjustment to the intangible assets will be depleted as per the above discussion. The change will be retroactively applied with restatement. The impact on the Trust's 2003 and prior year's results will be reported in the Trust's first quarter report as follows:

| | Increase (Decrease) |
|---|---|
| Opening accumulated earnings (Jan 2003) | $ 372,000 |
| Unit capital | 591,000 |
| Future site restoration | 2,641,000 |
| Fixed assets | 5,604,000 |
| Accumulated depletion | 1,821,000 |
| Accretion expense | 547,000 |
| Depletion expenses | (726,000) |

The calculation of the above requires an estimation of the amount of the Trust's petroleum reserves by field. This figure is calculated annually by an independent engineering firm and any adjustments are used to recalculate depletion and future site restoration. This calculation is to a large extent subjective. Reserve adjustments are affected by economic assumptions as well as estimates of petroleum products in place and methods of recovering those reserves. To the extent reserves are increased or decreased, depletion costs will vary. New rules for determining reserves, effective for 2003, may provide a level of consistency that may reduce the impact of reserve revisions that have plagued the resource industry in past years.

For the fiscal year ending December 31, 2003, the Trust expensed $8,203,000 (2002 - $7,570,000) for the above-described items. The increase of $663,000 over the 2002 balance is due primarily to the acquisition of Comstate Resources Income Trust (February 1, 2002) as well as additional capital costs resulting from our 2003 development drilling.

The Trust currently has an estimated reserve life of 13.4 (2002 - 12.8) years calculated using the Trust's gross reserves (prior to allowance for royalties) based on the third party engineering report dated January 1, 2004 and using estimated 2004 production rates. Therefore, depletion expense for the existing assets, excluding dry hole costs, will be less than 10 percent for 2004. The Trust's CBM development program has the potential to increase the Trusts current reserve life as natural gas production from this type of formation generally has a long reserve life.

## Income Taxes

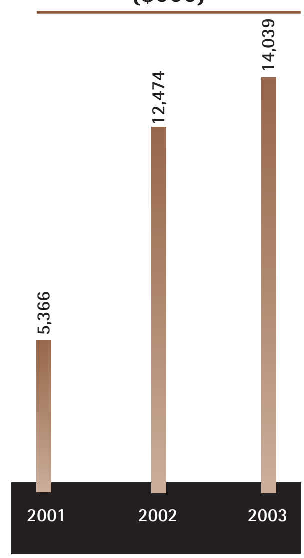
The Trust is required to allocate all taxable income to its Unitholders and as such will not incur any current taxes. The Trust operates its oil and gas interests through its 100 percent owned subsidiaries Bonterra Energy Corp. (Bonterra Corp.) and Comstate Resources Ltd. (Comstate Ltd.) Both Bonterra Corp. and Comstate Ltd. pay the majority of their income to the Trust through interest and royalty payments which are deductible for income tax purposes. For the years ended December 31, 2003 and 2002, Bonterra Corp. and Comstate Ltd. both paid to the Trust sufficient royalty and interest payments to eliminate all their taxable income. The current tax amount represents a provision for large corporation capital tax payable by the subsidiaries.

Future tax provision relates to the future taxes that exist within Bonterra Corp. and Comstate Ltd. The liability on the balance sheet and the corresponding income recovery relates to temporary differences existing between Bonterra Corp's. and Comstate Ltd.'s book value of its assets and its remaining tax pools.

## Net Earnings

The Trust is pleased to report net earnings of $14,039,000 for the fiscal year ended December 31, 2003. This is an increase of $1,565,000 over the Trusts 2002 net earnings of $12,474,000. The Trust recorded net earnings per unit in 2003 of $1.04 verses $0.96 in the 2002 fiscal year. This represents a return on Unitholders' equity of approximately 38.3 percent during the 2003 fiscal year based on year end Unitholders' equity.

**Net Earnings ($000)**




The Trust has an average cost for its oil and gas assets of $4.77 per BOE of proven reserves resulting in a low depletion provision. This low cost combined with low administration and interest expenses all contribute toward the significant net earnings.

## Cash Flow from Operations

Cash flow from operations for the fiscal year ending December 31, 2003 was $22,107,000 compared to $19,458,000 for the year ended December 31, 2002. Cash flow from operations is a non-GAAP measure that represents cash generated from operating activities before changes in non-cash working capital. Cash flow from operations may not be comparable to similar measures used by other organizations. The increase was primarily due to higher commodity prices as well as reduced operating costs. As with all oil and gas producers the Trust's cash flow is highly dependent on commodity prices. International events and control of crude oil production by OPEC and a potential shortage of natural gas in North America are likely factors that will result in 2004 commodity prices being high and having a positive impact on cash flow.

## Cash Netback

The following table illustrates the Trust's cash netback:

| $ per Barrel of Oil Equivalent (BOE) | 2003 | 2002 |
|---|---|---|
| Production volumes (BOE) | 1,137,997 | 1,160,152 |
| Gross production revenue | $ 38.18 | $ 34.65 |
| Royalties | (4.26) | (3.12) |
| Field operating | (12.50) | (13.12) |
| Field netback | 21.42 | 18.41 |
| General and administrative | (1.21) | (1.12) |
| Interest and taxes | (0.81) | (0.58) |
| Cash netback | $ 19.40 | $ 16.71 |

### Liquidity and Capital Resources

During 2003 the Trust participated in drilling 40 gross (12.1 net) wells at a total cost of $5,226,000. Of these wells, 31 (3.3 net) oil wells and 6 (5.83 net) gas wells were completed and on production during the fourth quarter 2003. The remaining three gas wells were not put on production until January 2004.

The Trust currently has plans to drill or recomplete 45 net shallow gas (including CBM) wells in 2004. Bonterra has been granted approval for reduced drill spacing units in respect of our CBM development. Drilling success in 2004 should substantially increase our natural gas production and reserves. Further infill drilling to enhance crude oil production is planned in several areas where the Trust has non-operated interests. The Trust will participate with the operator of the properties on these prospects. The currently planned development programs will be funded out of current cash flow and existing lines of credit.

The Trust is continuing in its efforts to acquire existing production through either property or corporate acquisitions. Acquisitions are being examined with the underlying consideration being enhancing value to our existing Unitholders.

The Trust has no contractual obligations that last more than a year other than its office lease agreement which is as follows:

| Contract Obligations | Total | Less than 1 year | 1 – 3 years | 4 – 5 years | After 5 years |
|---|---|---|---|---|---|
| Office lease | $ 605,808 | $ 259,632 | $ 346,176 | - | - |

At December 31, 2003 the Trust had debt of $21,216,000 (2002 – $18,357,000). The Trust still maintains a debt to annual cash flow ratio of less than one year. The Trust has a bank revolving credit facility of $32,000,000 at December 31, 2003 (December 31, 2002 - $24,000,000). The terms of the credit facility provide that the loan is due on demand and is subject to annual review. The credit facility has no fixed payment requirements. The amount available for borrowing under the credit facility is reduced by the amount of outstanding letters of credit. As at December 31, 2003, the Trust has a nominal amount of outstanding letters of credit. Collateral for the loan consists of a demand debenture providing a first floating charge over all of the Trust's assets, and a general security agreement.

Fourteen million dollars of the credit facility carries an interest rate of Canadian chartered bank prime with the balance at one-quarter percent above prime. As of December 31, 2003, the Trust had an outstanding balance under the facility of $17,466,000 (December 31, 2002 - $10,357,000).

Included in the Trust's debt of $21,216,000 at December 31, 2003, is a balance payable of $3,750,000 (December 31, 2002 - $8,000,000) payable to Comaplex Minerals Corp. The interest rate charged on the outstanding balance is bank prime less three-quarters of a percent. The security provided by the Trust for the loan is that the Trust has agreed to maintain a line of credit with its principal banker sufficient to repay the loan if demanded.

The Trust is authorized to issue an unlimited number of trust units without nominal or par value. The following outlines changes in the Trust's unit structure over the past two years.

| Issued | 2003 Number | 2003 Amount | 2002 Number | 2002 Amount |
|---|---|---|---|---|
| Trust Units | | | | |
| Balance, beginning of year | 13,368,405 | $49,607,447 | 8,692,226 | $12,975,678 |
| Issued on merger with Comstate | | | | |
| Resources Income Trust | - | - | 4,676,179 | 36,631,769 |
| Issued pursuant to Trust unit | | | | |
| option plan | 153,000 | 1,530,000 | - | - |
| Balance, end of year | 13,521,405 | $51,137,447 | 13,368,405 | $49,607,447 |

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,323,450 (2002 – 1,323,450) trust units. The exercise price of each option granted equals the market price of the trust unit on the date of grant and the option's maximum term is five years. Options vest one-third each year for the first three years of the option term.

A summary of the status of the Trust's unit option plan as of December 31, 2003 and 2002, and changes during the years ending on those dates is presented below:

| | 2003 | | 2002 | |
|---|---|---|---|---|
| | Options | Weighted-Average Exercise Price | Options | Weighted-Average Exercise Price |
| Outstanding at beginning | | | | |
| of year | 963,000 | $10.00 | - | $ - |
| Options granted | 211,000 | 14.26 | 963,000 | 10.00 |
| Options exercised | (153,000) | 10.00 | - | - |
| Options cancelled | (84,000) | 10.00 | - | - |
| Outstanding at end of year | 937,000 | $10.96 | 963,000 | $ 10.00 |
| Options exercisable at end | | | | |
| of year | 140,000 | $10.00 | - | $ - |

The following table summarizes information about fixed stock options outstanding at December 31, 2003:

| | Options Outstanding | | | Options Exercisable | |
|---|---|---|---|---|---|
| Range of Exercise Prices | Number Outstanding At 12/31/03 | Weighted-Average Remaining Contractual Life | Weighted-Average Exercise Price | Number Exercisable At 12/31/03 | Weighted-Average Exercise Price |
| $9.70-$10.00 | 762,000 | 3.1 years | $ 9.99 | 140,000 | $10.00 |
| $15.20 | 175,000 | 3.1 years | 15.20 | - | - |
| $9.70-$15.20 | 937,000 | 3.1 years | $10.96 | 140,000 | $10.00 |

The Trust accounts for its stock based compensation plan using intrinsic values. Under this method no costs are recognized in the financial statements for unit options granted to employees and directors when the options are issued at prevailing market prices. For fiscal years beginning on or after January 1, 2002, Canadian generally accepted accounting principles require disclosure of the impact on net earnings using the fair market value method for stock options issued on or after January 1, 2002. If the fair value method had been used, the Trusts net earnings for 2003 would be reduced by $211,000 (2002 - $55,000) and 2003 net earnings per unit would be reduced by $0.01 (2002 - Nil). The fair value of options granted has been estimated using the Black-Scholes option pricing model, assuming a weighted average risk free interest rate of 3.75 (2002 - 4.2) percent, expected weighted average volatility of 32 (2002 - 25) percent, expected weighted average life of 3.6 (2002 - 4.4) years and an annual dividend rate based on the distributions paid to the Unitholders during the year.

Effective January 1, 2004, the Trust will be required to report all stock options using the fair value method. The Trust will retroactively restate its financial information back to 2002. The impact to the December 31, 2003 financial information (including adjustments for 2002) is as follows:

| | Increase (Decrease) |
|---|---|
| Opening accumulated earnings (Jan 2003) | $(55,000) |
| Unit capital | 35,000 |
| Contributed surplus | 231,000 |
| General and administrative expense (2003) | 211,000 |

### Business Prospects, Risks, and Outlooks

The resource industry operates with a great deal of risk. The most significant risks may come from oil and natural gas price swings, the uncertainty of finding new reserves from drilling programs or acquisitions, competition within the industry, and increasing environmental controls and regulations.

The prices received for crude oil are established by world market forces and for natural gas by forces within North America. Fluctuations in pricing can have extremely positive or negative effects on the Trust's cash flow or in the value of its producing and non-producing oil and natural gas properties.

The Trust presently attempts to minimize these risks by pursuing both oil and natural gas activities and operates its oil and natural gas interests in areas which have long life reserves, where it has the technical expertise to enhance production, control operating costs and to increase margins of profit.

The Trust also maintains an active hedging program. Currently the Trust has forward sales agreements in place for approximately 35 percent on a BOE basis of its estimated 2004 production. The Trust uses a combination of fixed price swaps as well as no cost floor and collars to protect against commodity price declines. During 2003 the Trust incurred a net loss on its hedging of $3,150,000 (2002 - $928,000). The following schedule outlines the Trusts hedging position post December 31, 2003 as of the date of this report:

| Period of Agreement | Commodity | Volume per day | Index | Price (Cdn.) |
|---|---|---|---|---|
| January 1, 2004 to March 31, 2004 | Crude Oil | 600 barrels | WTI | $41.00 per barrel |
| March 1, 2004 to May 31, 2004 | Crude Oil | 500 barrels | WTI | $46.20 per barrel |
| April 1, 2004 to June 30, 2004 | Crude Oil | 500 barrels | WTI | $40.00 per barrel |
| July 1, 2004 to September 30, 2004 | Crude Oil | 500 barrels | WTI | $40.85 per barrel |
| October 1, 2004 to December 31, 2004 | Crude Oil | 500 barrels | WTI | $44.20 per barrel |
| January 1, 2005 to March 31, 2005 | Crude Oil | 600 barrels | WTI | $43.08 per barrel |
| January 1, 2004 to March 31, 2004 | Natural Gas | 1,800 GJ's | AECO | Floor of $5.00 and ceiling of $9.05 per GJ |
| April 1, 2004 to October 31, 2004 | Natural Gas | 1,500 GJ's | AECO | Floor of $4.75 and ceiling of $7.25 per GJ |
| April 1, 2004 to October 31, 2004 | Natural Gas | 2,000 GJ's | AECO | Floor of $5.75 and ceiling of $7.35 per GJ |

## Sensitivity Analysis

| Sensitivity analysis, as estimated for 2004: | | Cash Flow | Cash Flow Per Unit |
|---|---|---|---|
| U.S. $1.00 per barrel | | $804.000 | $0.059 |
| Canadian $0.10 per MCF | | $ 78,000 | $0.006 |
| Change of Canadian $0.01/U.S. $ exchange rate | | $477,000 | $0.035 |

## Management's Responsibility For Financial Statements

The information provided in this report, including the financial statements, is the responsibility of management. In the preparation of the statements, estimates are sometimes necessary to make a determination of future values for certain assets or liabilities. Management believes such estimates have been based on careful judgements and have been properly reflected in the accompanying financial statements.

Management maintains a system of internal controls to provide reasonable assurance that the Trust's assets are safeguarded and to facilitate the preparation of relevant and timely information.

Deloitte & Touche LLP has been appointed by the Unitholders to serve as the Trust's external auditors. They have examined the financial statements and provided their auditors' report. The audit committee has reviewed these financial statements with management and the auditors, and has reported to the Board of Directors. The Board of Directors has approved the financial statements as presented in this annual report.

George F. Fink
President and CEO

Garth E. Schultz
Vice President, Finance and CFO

## Auditors' Report

**To the Unitholders of Bonterra Energy Income Trust:**

We have audited the consolidated balance sheets of **Bonterra Energy Income Trust** as at December 31, 2003 and 2002 and the consolidated statements of Unitholders' equity, operations and accumulated earnings, and of cash flows for the years then ended. These consolidated financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these consolidated 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, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Calgary, Alberta
March 26, 2004

Deloitte & Touche LLP

Chartered Accountants

## Bonterra Energy Income Trust
## Consolidated Balance Sheets

| As at December 31 | 2003 | 2002 |
|---|---|---|
| *Assets* | | |
| **Current** | | |
| Accounts receivable | **$ 5,530,347** | $ 5,895,518 |
| Inventories | **359,686** | 321,750 |
| Prepaid expenses | **715,628** | 513,335 |
| Investments (at cost; quoted market value at December 31, 2003 - $2,931,149 December 31, 2002 - $724,166) | **460,846** | 460,846 |
| | **7,066,507** | 7,191,449 |
| **Property and Equipment** (*Note 2*) | | |
| Petroleum and natural gas properties and related equipment | **87,032,311** | 81,608,665 |
| Accumulated depletion and depreciation | **(19,545,211)** | (12,382,836) |
| | **67,487,100** | 69,225,829 |
| | **$74,553,607** | $76,417,278 |
| *Liabilities* | | |
| **Current** | | |
| Bank indebtedness | **$ 614,118** | $ 1,272,866 |
| Distributions payable | **1,622,569** | 1,470,525 |
| Accounts payable and accrued liabilities | **5,802,639** | 5,449,301 |
| Debt (*Note 3)* | **21,216,322** | 10,357,155 |
| | **29,255,648** | 18,549,847 |
| Debt (*Note 3*) | **-** | 8,000,000 |
| Future income tax liability *(Note 5)* | **41,063** | 175,478 |
| Future site restoration | **8,573,052** | 7,800,058 |
| | **37,869,763** | 34,525,383 |
| **Unitholders' Equity** | | |
| Unit capital (*Note 4*) | **51,137,447** | 49,607,447 |
| Accumulated earnings | **31,879,384** | 17,840,667 |
| Accumulated cash distributions | **(46,332,987)** | (25,556,219) |
| | **36,683,844** | 41,891,895 |
| | **$74,553,607** | $76,417,278 |

On behalf of the Board:

Director

Director

## Bonterra Energy Income Trust
## Consolidated Statements of Unitholders' Equity

| For the Years Ended December 31 | 2003 | 2002 |
|---|---|---|
| Unitholders equity, beginning of year | **$41,891,895** | $11,388,100 |
| Net earnings for the year | **14,038,717** | 12,474,465 |
| Capital contributions *(Note 4)* | **1,530,000** | 36,631,769 |
| Cash distributions | **(20,776,768)** | (18,602,439) |
| **Unitholders' Equity, End of Year** | **$36,683,844** | $41,891,895 |

## Bonterra Energy Income Trust
## Consolidated Statements of Operations and Accumulated Earnings

| For the Years Ended December 31 | 2003 | 2002 |
|---|---|---|
| **Revenue** | | |
| Oil and gas sales, net of royalties | | |
| of $5,071,927 (2002 - $3,773,298) | **$38,377,094** | $36,424,209 |
| Production costs | **(14,226,606)** | (15,226,323) |
| Alberta royalty tax credits | **223,822** | 158,112 |
| Interest and other | **27,581** | 42,421 |
| | **24,401,891** | 21,398,419 |
| **Expenses** | | |
| General and administrative | **1,371,674** | 1,297,880 |
| Interest on long-term debt | **893,939** | 670,933 |
| | **2,265,613** | 1,968,813 |
| **Cash Flow From Operations Before Current Taxes** | **22,136,278** | 19,429,606 |
| Depletion, depreciation and future site restoration | **8,202,982** | 7,569,765 |
| **Earnings Before Income Taxes** | **13,933,296** | 11,859,841 |
| Income taxes (recovery) (*Note 5*) | | |
| Current | **28,994** | (28,103) |
| Future | **(134,415)** | (586,521) |
| | **(105,421)** | (614,624) |
| **Net Earnings for the Year** | **14,038,717** | 12,474,465 |
| Accumulated earnings at beginning of year | **17,840,667** | 5,366,202 |
| **Accumulated Earnings at End of Year** | **$31,879,384** | $17,840,667 |
| **Net Earnings Per Unit - Basic** *(Note 1)* | **$ 1.05** | $ 0.96 |
| **Net Earnings Per Unit - Diluted** *(Note 1)* | **$ 1.04** | $ 0.96 |

## Bonterra Energy Income Trust
## Consolidated Statements of Cash Flows

| For the Periods Ended December 31 | 2003 | 2002 |
|---|---|---|
| **Operating Activities** | | |
| Net earnings for the year | **$14,038,717** | $12,474,465 |
| Items not affecting cash | | |
| Depletion, depreciation and future site restoration | **8,202,982** | 7,569,765 |
| Future income taxes | **(134,415)** | (586,521) |
| **Cash Flow from Operations** | **22,107,284** | 19,457,709 |
| Change in non-cash operating working capital | | |
| Accounts receivable | **365,171** | (583,485) |
| Inventories | **(37,936)** | (132,411) |
| Prepaid expenses | **(202,293)** | 169,726 |
| Accounts payable and accrued liabilities | **353,335** | 643,996 |
| | **478,277** | 97,826 |
| | **22,585,561** | 19,555,535 |
| **Financing Activities** | | |
| Increase in long-term debt | **2,859,167** | 3,717,418 |
| Stock option proceeds | **1,530,000** | - |
| Unit issue costs | **-** | (93,075) |
| Unit distributions payable upon merger | **-** | (794,606) |
| Unit distributions | **(20,624,721)** | (18,088,056) |
| | **(16,235,554)** | (15,258,319) |
| **Investing Activities** | | |
| Property and equipment expenditures | **(5,691,259)** | (5,006,521) |
| Bank indebtedness assumed upon acquisition (*Note 2*) | **-** | (115,522) |
| | **(5,691,259)** | (5,122,043) |
| Net cash inflow (outflow) | **658,748** | **(824,827)** |
| Bank indebtedness, beginning of year | **(1,272,866)** | (448,039) |
| **Bank Indebtedness, End of Year** | **$ (614,118)** | $(1,272,866) |

Cash interest and taxes paid *(see Notes 3 and 5)*

## 1. SIGNIFICANT ACCOUNTING POLICIES

### Consolidation

These consolidated financial statements include the accounts of the Trust and its wholly owned subsidiaries Bonterra Energy Corp. and Comstate Resources Ltd.

### Measurement Uncertainty

The amounts recorded for depreciation and depletion of petroleum and natural gas property and equipment and for future site restoration and reclamation are based on estimates of petroleum and natural gas reserves and future costs. By their nature, these estimates are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material.

### Inventories

Inventories consist of materials and supplies that are valued at the lower of cost or net realizable value.

### Investments

Investments are carried at the lower of cost and market value.

### Property and Equipment

Petroleum and Natural Gas Properties and Related Equipment

The Trust follows the successful efforts method of accounting for petroleum and natural gas properties and related equipment. Costs of acquiring unproved properties are capitalized and amortized on a straight-line basis over the lives of the related leases. These costs are assessed annually for impairment. When property is found to contain proved reserves as determined by the Trust's engineers, the related net book value is depleted on the unit-of-production basis, calculated by field. The costs of dry holes and abandoned properties are charged to operations. Geological costs, lease rentals and carrying costs are charged to income as incurred. Costs of drilling exploratory and development wells that result in additions to proved reserves are capitalized and depleted on the unit-of-production basis. Tangible equipment is depreciated on a straight-line basis over ten years.

Furniture, Fixtures and Office Equipment

These assets are recorded at cost and depreciated over a three to ten year period representing their estimated useful lives.

### Income Taxes

Income taxes are calculated using the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the consolidated financial statements of the Trust and their respective tax bases, using substantively enacted income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the Unitholders. As the Trust allocates all of its taxable income to the Unitholders in accordance with the Trust Indenture, and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for income tax expense has been made in the Trust.

In the Trust structure, payments are made between the Trusts operating subsidiaries and the Trust which result in the transferring of taxable income from the operating subsidiaries to individual Unitholders. These payments may reduce future income tax liabilities previously recorded by the operating companies which would be recognized as a recovery of income tax in the period incurred.

### Future Site Restoration

The Trust provides for abandonment costs and future site restoration over the estimated production life of its property and equipment. Estimates of these amounts are based on the anticipated method and extent of site restoration using current costs and in accordance with existing legislation and industry practice. The annual charge calculated on a unit-of-production basis is included with depletion, depreciation and future site restoration.

### Trust-Unit-Based Compensation Plan

The Trust has a trust-unit-based compensation plan, which is described in Note 4. No compensation expense is recognized for these plans when unit options are issued at the prevailing market prices. Any consideration paid by employees or directors on the exercise of these options is recorded as unit capital. For options issued after January 1, 2002, the fair values are determined and the impact on earnings is disclosed as pro forma information.

### Revenue Recognition

Revenues associated with sales of petroleum are recorded when produced and for natural gas when title passes to the customer.

### Hedging

The Trust uses derivative instruments to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. Gains and losses on these contracts are recognized as a component of oil and gas sales.

### Joint Interest Operations

Significant portions of the Trust's oil and gas operations are conducted with other parties and accordingly the financial statements reflect only the Trust's proportionate interest in such activities.

### Net Earnings Per Unit

Basic earnings per unit are computed by dividing earnings by the weighted average number of units outstanding during the year. Diluted per unit amounts reflect the potential dilution that could occur if options or warrants to purchase trust units were exercised. The treasury stock method is used to determine the dilutive effect of trust unit options and warrants, whereby proceeds from the exercise of trust unit options or other dilutive instruments are assumed to be used to purchase trust units at the average market price during the period.

The number of trust units used to calculate diluted net earnings per share for the year ended December 31, 2003 of 13,558,519 (2002 – 12,978,723) included the weighted average number of shares outstanding of 13,394,363 (2002 – 12,978,723) plus 164,156 (2002 - Nil) shares related to the dilutive effect of unit options.

## 2. PROPERTY AND EQUIPMENT

| | 2003 | | 2002 | |
|---|---|---|---|---|
| | Cost | Accumulated Depletion and Depreciation | Cost | Accumulated Depletion and Depreciation |
| Undeveloped land | $ 186,374 | $ - | $ 64,632 | $ - |
| Petroleum and natural gas properties and related equipment | 86,169,541 | 19,352,474 | 80,907,617 | 12,276,863 |
| Furniture, equipment and other | 676,396 | 192,737 | 636,416 | 105,973 |
| | $87,032,311 | $19,545,211 | $81,608,665 | $12,382,836 |

On December 17, 2001, the Trust announced its intention to combine with Comstate Resources Income Trust "Comstate Trust" by way of merger whereby each unit holder of the Trust would receive 0.885 of a unit of Comstate Trust. The transaction was accounted for as a reverse takeover of Comstate Trust by the Trust as the former Unitholders of the Trust own greater than 50% of the units of the new trust. The merger arrangement was approved by the Unitholders of both Comstate Trust and the Trust on January 24, 2002 and was effective January 31, 2002.

As this transaction was accounted for as a reverse takeover, the assets and liabilities of the Trust remain at their book values, while the assets and liabilities of Comstate Trust are recorded at their fair values on January 31, 2002. The net assets of Comstate Trust acquired through this merger transaction were as follows:

| | |
|---|---|
| Net Non-cash Working Capital | $ 68,048 |
| Bank Indebtedness | (115,522) |
| Investments | 460,846 |
| Property and Equipment | 47,696,922 |
| Long-term Debt | (6,750,000) |
| Future Tax Liability | (314,658) |
| Future Site Restoration | (4,320,792) |
| | $36,724,844 |
| Trust Units Issued | $36,631,769 |
| Unit Issue Costs | 93,075 |
| | $36,724,844 |

At December 31, 2003, the estimated future site restoration costs to be accrued over the life of the remaining proved reserves are $18,909,639 (2002 - $18,944,765)

## 3. DEBT

The Trust has a bank revolving credit facility of $32,000,000 at December 31, 2003 (2002 - $24,000,000). The terms of the credit facility provide that the loan is due on demand and is subject to annual review. The credit facility has no fixed payment requirements. The amount available for borrowing under the credit facility is reduced by the amount of outstanding letters of credit. Collateral for the loan consists of a demand debenture providing a first floating charge over all of the Trust's assets, and a general security agreement.

Fourteen million dollars of the credit facility carries an interest rate of Canadian chartered bank prime with the balance at one-quarter percent above prime. As of December 31, 2003, the Trust had an outstanding balance under the facility of $17,466,322. The Trust has classified borrowing under its bank facilities as a current liability as required by guidance under the CICA's Emerging Issues Committee Abstract 122. It has been management's experience that these types of loans which are required to be classified as a current liability are seldom called by principal bankers as long as all the terms and conditions of the loan are complied with. Cash interest paid during the year ended December 31, 2003 for this loan was $635,517 (2002 - $398,499).

As at December 31, 2003, the Trust has a balance payable of $3,750,000 (2002 - $8,000,000) to Comaplex Minerals Corp. (Comaplex) a company with common directors and management (see note 8). The interest rate is bank prime less three-quarters of a percent. The security provided by the Trust for the loan is that the Trust has agreed to maintain a line of credit with its principal banker sufficient to repay the loan if demanded. The loan has been reclassified as short-term as it is payable on demand. Cash interest paid during the twelve months ended December 31, 2003 for this loan was $256,587 (2002 - $269,346).

## 4. UNIT CAPITAL

### Authorized

The Trust is authorized to issue an unlimited number of trust units without nominal or par value

| Issued | 2003 Number | 2003 Amount | 2002 Number | 2002 Amount |
|---|---|---|---|---|
| Trust Units | | | | |
| Balance, beginning of year | 13,368,405 | $49,607,447 | 8,692,226 | $12,975,678 |
| Issued on merger with Comstate Resources Income Trust | - | - | 4,676,179 | 36,631,769 |
| Issued pursuant to Trust unit option plan | 153,000 | 1,530,000 | - | - |
| Balance, end of year | 13,521,405 | $51,137,447 | 13,368,405 | $49,607,447 |

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,323,450 (2002 – 1,323,450) trust units. The exercise price of each option granted equals the market price of the trust unit on the date of grant and the option's maximum term is five years. Options vest one-third each year for the first three years of the option term.

A summary of the status of the Trust's unit option plan as of December 31, 2003 and 2002, and changes during the years ending on those dates is presented:

| | 2003 Options | 2003 Weighted-Average Exercise Price | 2002 Options | 2002 Weighted-Average Exercise Price |
|---|---|---|---|---|
| Outstanding at beginning of year | 963,000 | $10.00 | - | $ - |
| Options granted | 211,000 | 14.26 | 963,000 | 10.00 |
| Options exercised | (153,000) | 10.00 | - | - |
| Options cancelled | (84,000) | 10.00 | - | - |
| Outstanding at end of year | 937,000 | $10.96 | 963,000 | $ 10.00 |
| Options exercisable at end of year | 140,000 | $10.00 | - | $ - |

The following table summarizes information about fixed stock options outstanding at December 31, 2003:

| | Options Outstanding | | | Options Exercisable | |
|---|---|---|---|---|---|
| Range of Exercise Prices | Number Outstanding At 12/31/03 | Weighted-Average Remaining Contractual Life | Weighted-Average Exercise Price | Number Exercisable At 12/31/03 | Weighted-Average Exercise Price |
| $9.70-$10.00 | 762,000 | 3.1 years | $ 9.99 | 140,000 | $10.00 |
| $15.20 | 175,000 | 3.1 years | 15.20 | - | - |
| $9.70-$15.20 | 937,000 | 3.1 years | $10.96 | 140,000 | $10.00 |

The Trust accounts for its stock based compensation plan using intrinsic values. Under this method no costs are recognized in the financial statements for unit options granted to employees and directors when the options are issued at prevailing market prices. For fiscal years beginning on or after January 1, 2002, Canadian generally accepted accounting principles require disclosure of the impact on net earnings using the fair market value method for stock options issued on or after January 1, 2002. If the fair value method had been used, the Trust's net earnings for 2003 would be reduced by $211,000 (2002 - $55,000) and 2003 net earnings per unit would be reduced by $0.01 (2002 - Nil). The fair value of options granted has been estimated using the Black-Scholes option pricing model, assuming a weighted average risk free interest rate of 3.75 (2002 - 4.2) percent, expected weighted average volatility of 32 (2002 - 25) percent, expected weighted average life of 3.6 (2002 - 4.4) years and an annual dividend rate based on the distributions paid to the Unitholders during the year.

## 5. INCOME TAXES

The Trust has recorded a future income tax liability. The liability relates to the following temporary differences:

| | 2003 | 2002 |
|---|---|---|
| Temporary differences related to assets and liabilities of the subsidiary companies | $ 797,588 | $ 801,425 |
| Finance expense charged to Unitholders' equity | (83,550) | (150,160) |
| Tax loss carry forward | (672,975) | (475,787) |
| | $ 41,063 | $ 175,478 |

Income tax expense varies from the amounts that would be computed by applying Canadian federal and provincial income tax rates as follows:

| | 2003 | 2002 |
|---|---|---|
| Earnings before income taxes | $13,933,296 | $11,859,841 |
| Combined federal and provincial income tax rates | 41.14% | 42.75% |
| Income tax provision calculated using statutory tax rates | 5,732,158 | 5,070,082 |
| Increase (decrease) in income taxes resulting from: | | |
| Non-deductible crown royalties | 1,236,917 | 1,391,837 |
| Resource allowance | (1,998,135) | (2,476,610) |
| Trust income allocated to Unitholders | (5,050,518) | (4,489,166) |
| Income tax rate reduction | 31,633 | (44,082) |
| Income tax recovery | - | (28,103) |
| Other | (57,476) | (38,582) |
| | $ (105,421) | $ (614,624) |

The Trust and its subsidiary have the following tax pools, which may be used to reduce taxable income in future years, limited to the applicable rates of utilization:

| | Rate of Utilization % | Amount |
|---|---|---|
| Undepreciated capital costs | 20-100 | $ 4,832,818 |
| Canadian oil and gas property expenses | 10 | 19,543,724 |
| Canadian development expenses | 30 | 2,180,303 |
| Canadian exploration expenses | 100 | 1,266,728 |
| Income tax losses | 100 | 2,007,262 |
| Finance expenses | 20 | 395,833 |
| | | $30,226,668 |

Cash taxes paid in 2003 was $12,059 (2002 - $4,642)

## 6. FINANCIAL INSTRUMENTS

### Fair Values

The Trust's financial instruments included in the balance sheet are comprised of accounts receivable and current liabilities, including the revolving demand loan and the loan payable to Comaplex. The fair values of these financial instruments approximate their carrying value due to the short-term maturity of those instruments. Borrowings under bank credit facilities and the Comaplex loan are for short periods with variable interest rates, thus, carrying values approximate fair value.

### Credit Risk

Substantially all of the Trust's accounts receivable are due from customers in the oil and gas industry and are subject to normal industry credit risks. The carrying value of accounts receivable reflects management's assessment of associated credit risks.

### Interest Rate Risk

The Trust's bank debt is comprised of a revolving loan and the Comaplex loan which are at variable rates, and as such, the Trust is exposed to interest rate risk.

### Commodity Price Risk

The nature of the Trust's operations results in exposure to fluctuations in commodity prices and exchange rates. The Trust monitors and when appropriate uses derivative financial instruments to manage its exposure to these risks.

## 7. COMMITMENTS, CONTINGENCIES AND GUARANTEES

The Trust entered into the following commodity hedging transactions in 2003 for a portion of its 2004 production:

| Period of Agreement | Commodity | Volume per day | Index | Price (Cdn.) |
|---|---|---|---|---|
| January 1, 2004 to March 31, 2004 | Crude Oil | 600 barrels | WTI | $41.00 per barrel |
| April 1, 2004 to June 30, 2004 | Crude Oil | 500 barrels | WTI | $40.00 per barrel |
| January 1, 2004 to March 31, 2004 | Natural Gas | 1,800 GJ's | AECO | $5.00 per GJ floor and $9.05 per GJ ceiling |

## 8. RELATED PARTY TRANSACTIONS

During 2003, the Trust received a management fee from Novitas Energy Ltd. (Novitas) (a company with common directors and management) for management services of $10,000 (2002 - $5,000) per month plus five percent of before tax income. Total receipts during 2003 were $120,000 (2002 - $73,300) and have been included as a recovery of general and administrative expenses.

Novitas also paid administrative fees on a per well basis to the Trust for the administration of its oil and gas properties. Total amount paid during 2003 was $148,000 (2002 - $128,500). This amount has also been recorded as a recovery of general and administrative expenses.

The Trust received a management fee from Comaplex of $210,000 (2002 - $120,000) for management services and office administration. This cost has been included as a recovery in general and administrative expenses.

The Trust owns at December 31, 2003, 689,682 (2002 - 689,682) common shares of Comaplex with a cost of $460,844 (2002 - $460,844) and a quoted market value of $2,103,530 (2002 - $724,166). Included in the Trust's debt is an amount owing to Comaplex (see Note 3).

## 9. SUBSEQUENT EVENT- COMMITMENTS

The Trust entered into the following commodity hedging transactions subsequent to December 31, 2003 for a portion of its future production:

| Period of Agreement | Commodity | Volume per day | Index | Price (Cdn.) |
|---|---|---|---|---|
| July 1, 2004 to September 30, 2004 | Crude Oil | 500 barrels | WTI | $40.85 per barrel |
| March 1, 2004 to May 31, 2004 | Crude Oil | 500 barrels | WTI | $46.20 per barrel |
| October 1, 2004 to December 31, 2004 | Crude Oil | 500 barrels | WTI | $44.20 per barrel |
| January 1, 2005 to March 31, 2005 | Crude Oil | 500 barrels | WTI | $43.08 per barrel |
| April 1, 2004 to October 31, 2004 | Natural Gas | 1,500 GJ's | AECO | $4.75 per GJ floor and $7.25 per GJ ceiling |
| April 1, 2004 to October 31, 2004 | Natural Gas | 2,000 GJ's | AECO | $5.75 per GJ floor and $7.35 per GJ ceiling |

## Trust Information

### Board of Directors

G.J. Drummond, Nassau, Bahamas

G.F. Fink, Calgary, Alberta

C.R. Jonsson, Vancouver, British Columbia

F. W. Woodward, Calgary, Alberta

### Officers

G.F. Fink – President and CEO

R.M. Jarock – Vice President Corporate Development & Operations Manager

G.E. Schultz – Vice President, Finance & Secretary

### Registrar & Transfer Agent

Olympia Trust Company, Calgary, Alberta

### Auditors

Deloitte & Touche LLP, Calgary, Alberta

### Solicitors

Parlee McLaws, Calgary, Alberta

Tupper, Jonsson & Yeadon, Vancouver, British Columbia

### Bankers

The Royal Bank of Canada, Calgary, Alberta

### Stock Listing

The Toronto Stock Exchange, Toronto, Ontario

Trading symbol: BNE.UN

### Web Site

**www.bonterraenergy.com**

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