Bonterra
Energy Income Trust

2001 Annual Report

Trust Profile

Bonterra Energy Income Trust. (TSE 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 unitholders 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.

Notice of Annual Meeting

The Annual Meeting of Unitholders will be held on Tuesday, June 18, 2002, in the Barclay Room at the Westin Hotel, 320 Fourth Avenue S.W., Calgary, Alberta, at 11:00 a.m. (Calgary time).

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Bonterra
Energy Income Trust

Highlights

	$ 2001
For the Six Months Ended December 31, 2001	
Financial ($000, except $ per unit)	
Revenue – oil and gas (net of royalties)	11,257
Distributions per Unit	0.80
Cash Flow from Operations	6,446
Per Unit Diluted	0.74
Net Earnings	5,366
Per Unit Diluted	0.62
Capital Expenditures and Acquisitions	1,037
Outstanding Debt	7,890
Unitholders' Equity	11,388
Units Outstanding (weighted average) (000's)	8,692
Operations	
Oil and Liquids (*barrels per day*)	1,531
Average Price ($ *per barrel*)	38.05
Natural Gas (MCF *per day*)	1,408
Average Price ($ *per* MCF)	4.55
Reserves (*proven producing*)	
Oil and Liquids (*barrels in* 000's)	7,069
Natural Gas (MCF *in* 000's)	6,320

Report to Unitholders

Bonterra Energy Income Trust ("Bonterra") is pleased to report its first operational and financial results since converting to a trust from a corporation on July 1, 2001. The results are for the six-month period ending December 31, 2001. As previously announced, the trust was mainly formed to provide a more favorable environment for taxation and to provide a monthly return to the Unitholders.

Also, as previously announced when Bonterra Energy Income Trust was formed, the intent was to merge it with Comstate Resources Income Trust. This merger was completed on January 31, 2002.

Operations

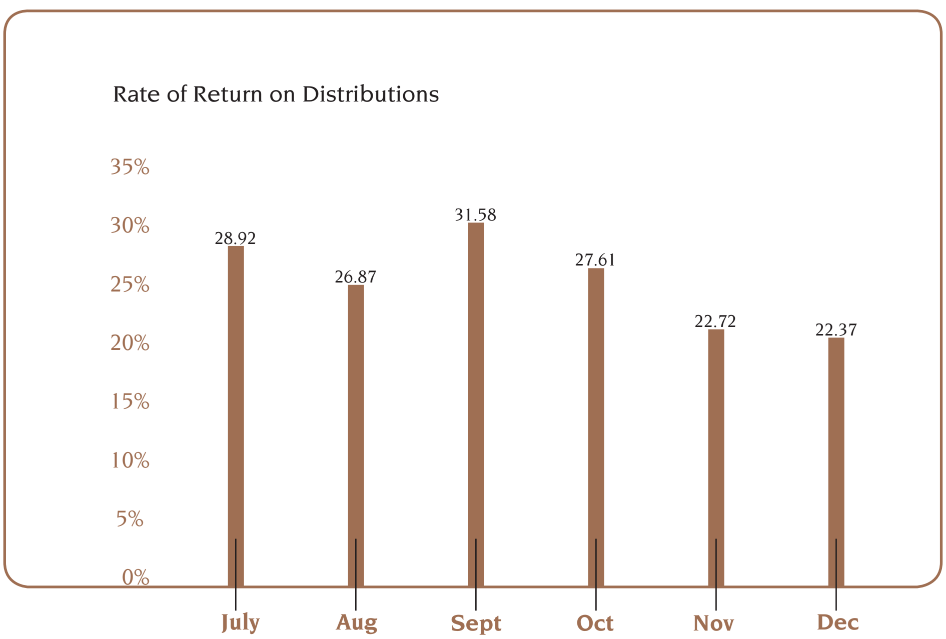
Bonterra's production is ideally suited for a trust. Approximately 80 percent of its production is mainly light, sweet gravity crude and liquids, and the remaining 20 percent natural gas is sweet long-life production. The life index for the trust's proven producing reserves is approximately 12 years, which is significantly higher than most other trusts.

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 decline rate is approximately 6 percent.

Production volumes for the six-month period were slightly lower than the forecast volumes mainly due to delays in being able to tie-in some gas production. It is anticipated that all of these wells should be on production during the first half of 2002.

Financial

Bonterra's distribution for the six-month period was $0.80 per Unit, of which 64.5 percent is taxable and 35.5 percent is a return of capital. On an annualized basis, the distribution generally exceeded a rate of return of 20 percent (dependent on Unit price), representing one of the higher returns for trusts.



Rate of return based on average monthly price of units.

Gross revenue from commodity sales of $11,257,000 for the six-month period was slightly lower than the forecast amount. The reduction is due to lower commodity prices and slightly lower production volumes than forecast. Actual prices were $32.94 per barrel of oil and natural gas liquids, and $3.46 per MCF for natural gas, compared to the price forecast provided by the trust's independent engineering firm of $40.32 per barrel and $7.27 per MCF. Actual prices received, including hedging gains, were $38.05 per barrel and $4.55 per MCF.

At year-end Bonterra's long-term debt was approximately $7,890,000, which is approximately 7 months cash flow on an annualized basis. This debt to cash flow level is much lower than most other trust's debt to cash flow levels.

Outlook

The objectives for the trust are to increase its production volumes in the future by developing its existing properties and by acquiring additional production. The January 31, 2002 merger with Comstate Resources Income Trust will increase Bonterra's production volumes by approximately 80 percent. Management is aggressively pursuing further acquisitions and is hopeful that additional production will be acquired in 2002.

In 2002 Bonterra will also be aggressively evaluating potential production from coal beds in the Pembina area of Alberta. The trust will be testing a number of wells to determine production volumes of natural gas from the shallow coal beds to better assess the economic potential for this type of production. Further information about results will be released on a timely basis.

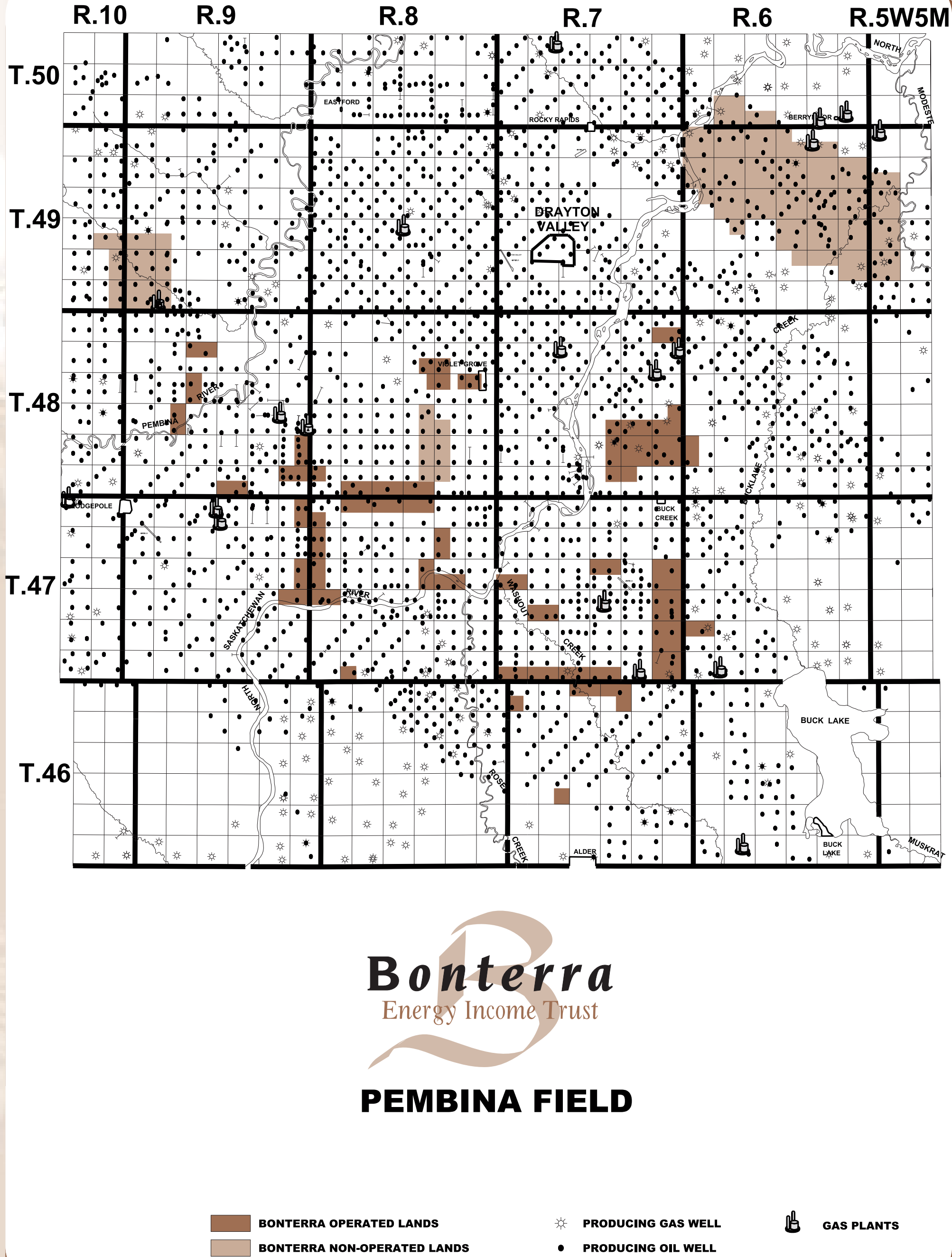
The trust is optimistic that if commodity prices are reasonable, the trust should be able to continue to provide high returns and additional capital appreciation. It should be noted that since Bonterra Energy Corp. (predecessor to the Trust) was incorporated and listed publicly in mid 1998, for every $1.00 invested at that time, it is worth approximately $20.00 in March 2002.

Outlook

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

Submitted on behalf of the Board of Directors,

George F. Fink
President and Director



Bonterra
Energy Income Trust

PEMBINA FIELD

Reserves

The Trust engaged the services of an independent engineering firm to prepare a reserve evaluation with an effective date of January 1, 2002. The reserves are located in the Provinces of Alberta and Saskatchewan. The majority of the Company's production is comprised of light sweet crude, which results in higher oil prices, and better marketing opportunities. The Company's main oil producing areas are located in the Pembina area of Alberta and Dodsland area of Saskatchewan. Oil and natural gas proven reserve estimates at December 31, 2001, before royalties, are as follows:

	Crude Oil and Liquids		Natural Gas	
	Proven	Probable	Proven	Probable
	(MBbls)		(MMCF)	
July 1, 2001	7,369	69	4,698	62
Production	(282)	–	(259)	–
Drilling additions	63	–	632	–
Evaluation adjustments to reserves	217	15	1,249	(26)
December 31, 2001	7,069	84	6,320	36
Life index (years) - December 31, 2001	12.5		12.2	

The reserve values in the following table, "Estimated Present Worth of Reserves", are based upon proved producing reserve estimates at December 31, 2001.

Estimated Present Worth Of Future Net Production Revenue

		Discounted at the rate of		
($ thousands)	$ Undiscounted	10%	15%	20%
Proven developed producing reserves	124,528	58,605	46,950	39,498
Probable reserves, risked at 50%	1,025	600	480	394
Proven and probable reserves at December 31, 2001	125,553	59,205	47,430	39,892

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)
2002	34.49	3.87	21.59	23.14	35.32
2003	32.18	4.31	19.09	20.39	32.96
2004	32.37	4.22	18.13	19.30	33.15
2005	32.88	4.29	18.41	19.60	33.67
2006	33.38	4.37	18.69	19.90	34.18
2007	33.88	4.45	18.98	20.20	34.70
2008	34.40	4.53	19.27	20.51	35.23
2009	34.92	4.61	19.56	20.82	35.76
2010	35.45	4.69	19.86	21.14	36.30
2011	35.99	4.78	20.16	21.46	36.86
2012	36.53	4.86	20.46	21.78	37.42

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.

	Oil and NGL (Bbls/day) 2001	Natural Gas (MCF/day) 2001
Pembina, Alberta	972	986
Dodsland, Saskatchewan	500	354
Pinto, Saskatchewan	59	68
	1,531	1,408

Land Holdings

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

	Gross Acres	Net Acres
Alberta	36,034	28,080
Saskatchewan	29,630	17,768
	65,664	45,848

Petroleum and Natural Gas Capital Expenditures

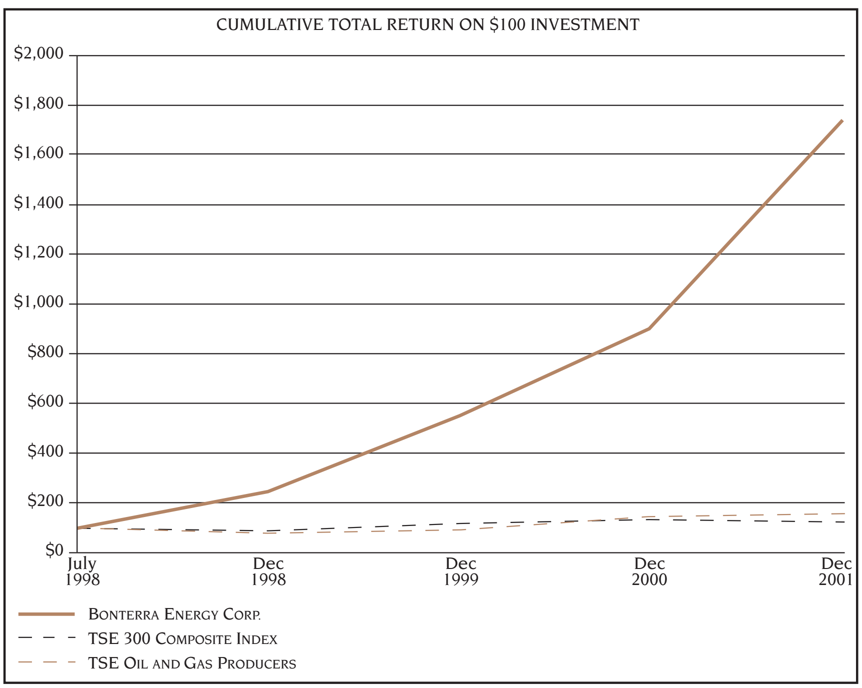
The following table summarizes petroleum and natural gas capital expenditures incurred by the Trust on acquisitions, land, seismic, exploration and development drilling and production facilities for the period:

Period ended December 31	$	2001
Exploration and development costs	$	964,200
Pipeline projects		292,900
Seismic		10,100
Land costs		62,300
Net petroleum and natural gas capital expenditures	$	1,329,500

Drilling History

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

	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%



Note 1: Includes the results of Bonterra Energy Corp. Prior to July 1, 2001

Note 2: Includes distributions of $0.80

Property Discussions

The Trust's producing properties are located in the Pembina area of Alberta, the Dodsland area in southwest Saskatchewan, the Pinto area in southeast Saskatchewan and production has recently commenced from the Angling area in east central Alberta. Bonterra continues to acquire exploration lands in the Pembina area of Alberta.

Pembina Area, Central Alberta

The Pembina field is the largest conventional oil field in Canada and our most significant producing property. Our production is predominately predictable, long life, low decline and high quality light oil from the Cardium formation which is located at a depth of approximately 5,000 feet. Bonterra operates approximately 75 percent of its production in this large core area which allows for significant operating efficiencies. The property contains approximately 117 gross (98 net) operated producing wells with an 84 percent average working interest and 189 gross (32 net) non-operated producing wells with an approximate 17 percent average working interest.

Our 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 also be a significant area for the potential development of additional oil and natural gas zones. The Trust continues to increase it's holding in the area to take advantage of these opportunities.

Bonterra has been able to increase oil production volumes and reserves through the successful drilling of wells into the shallower Belly River formation. The Belly River produces high quality light sweet oil from a depth of approximately 3,600 feet. There is also the potential to increase production from the Cardium formation through infill drilling in select areas of the field.

Bonterra has also been successful in increasing natural gas production and reserves by drilling multi-zone shallow gas wells into the Edmonton and Paskapoo formations. The company is targeting several productive sands that range in depth from 900 to 2,400 feet. Bonterra will continue to build on our previous exploration success in the area and develop these low cost shallow natural gas reserves.

Bonterra has been conducting tests to evaluate the feasibility of coal bed methane (CBM) production with encouraging initial results. The Trust 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 company 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 2,300 feet. Under terms of an existing agreement Bonterra had an option to acquire additional production in this area. The option was exercised in 2001 and an additional 66 gross wells (64 net) were acquired. Bonterra now operates approximately 426 gross (374 net) wells with an average working interest of 88 percent.

This is low rate stable production so cost control is an important focus 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.

Pinto Area, Southeast Saskatchewan

The Pinto property produces slightly sour gravity oil and solution gas from the Midale formation. The Trust has an average working interest of approximately 95 percent in the area. Bonterra continues to evaluate this area to determine if further optimization programs may increase overall profitability for the property.

Angling Area, East Central Alberta

Angling is a new area that Bonterra has successfully advanced from an exploration property to a producing property in early 2002. The 100 percent operated property consists of sweet shallow gas production from the Colony formation. The Trust continues to look to increase its' holdings in the area and to find similar exploration opportunities.

Management's Discussion and Analysis

This report 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 period ended December 31, 2001, together with the notes related thereto.

Production

The Trust's average production of oil and natural gas liquids was 1,531 (1,553 during the last three months) barrels per day. The Trust's natural gas production averaged 1,408 (1,580 during the last three months) MCF per day for the six month period ending December 31, 2001. Production was approximately 250 MCF per day below forecast due to delays in tying in our Angling, Alberta production. Subsequent to year end, this production was on stream at a rate of approximately 400 MCF per day.

Revenue

Gross revenue from petroleum and natural gas sales was $11,257,362. The average price received for crude oil and natural gas liquids including hedging, was $38.05 per barrel and $4.55 per MCF of natural gas. Actual prices received during the period ending December 31, 2001 were $32.94 per barrel of oil and natural gas liquids and $3.46 per MCF for natural gas. The forecast prices, excluding hedging adjustments, were $35.94 Cdn per barrel and $4.00 per MCF.

The Trust has hedging agreements in place from April 1, 2002 to October 31, 2003 for 1,000 GJ's (approximately 950 MCF) per day of natural gas at $3.77 Cdn. per GJ (approximately $3.97 per MCF), from May 1, 2002 to October 31, 2002 for 625 GJ's (approximately 590 MCF) per day of natural gas at $4.30 Cdn. per GJ (approximately $4.53 per MCF) and for 600 barrels per day of crude oil at a price of $37.97 Cdn. per barrel for the period April 1, 2002 to December 31, 2002.

Royalties

Royalties paid by the Trust consist primarily of Crown royalties paid to the Provinces of Alberta and Saskatchewan. During the period the Trust paid $592,990 in Crown royalties and $119,333 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 6 percent and approximately 1 percent for other royalties. The Trust is eligible for Alberta Crown Royalty rebates for Alberta production from a small amount of its purchased wells as well as on newly drilled wells.

Production Costs

Production costs totalled $4,097,781 in the six month period that the Trust operated in 2001. This was in line with forecasted operating costs, however, on a BOE basis operating costs were $12.61 (using a 6 to 1 conversion) per BOE which is higher than both original and revised forecasted amounts. The increase on a per barrel basis was due to delays in tying in lower cost natural gas production until 2002. Additional operating costs were incurred due to a major field maintenance program involving the repair and maintenance of all Pembina area oil facilities during the months of October and November 2001.

General and Administrative Expense

General and administrative expenses excluding management fees were $244,803 or $0.75 per BOE. Total administrative costs including the management fee of $323,500 were $568,303 or $1.75 per BOE. Both of these figures are in line with revised forecasted numbers presented in the Trust's September 30, 2001 quarterly report.

The Trust has entered into a management agreement with Comstate Resources Ltd. (Comstate) to provide field operations, management and general office services. Fees charged for field operations are charged on a per well basis. Fees associated with well operations are charged to production costs as incurred. Fees for management and general office services consist of $30,000 per month plus three percent of before tax net income. Effective February 1, 2002, Comstate became a wholly owned subsidiary of the Trust and the Trust is no longer charged a management fee.

Interest Expense

Interest expense for the 2001 fiscal period of the Trust was $200,307. Interest expense was slightly higher than forecast due to increases in loans resulting from larger capital expenditures for drilling additional gas wells than forecast as well as lower than forecast revenues resulting in lower repayments of loans than anticipated.

Interest rate charges during the period on the outstanding debt averaged 4.85 percent. The Trust has the ability to use Bankers Acceptances (BA's) as part of its loan facility. Interest charges on BA's are generally one half percent lower than that charged on the general loan account.

Gain on Disposal of Property

On September 28, 2001, the Trust's subsidiary, Novitas Energy Ltd. (Novitas), went public on the Canadian Venture Exchange (since renamed TSX Venture Exchange) and ceased to be a subsidiary. With Novitas no longer being a subsidiary of the Trust the gain on disposition of $294,206 from the sale of an oil and gas property from Bonterra to Novitas (original transaction of Novitas) had to be adjusted. The gain represents the difference between the Trust's book value of the property and the fair value of the property sold to Novitas for cash proceeds of $650,000.

Depletion, Depreciation, Future Site Restoration and Dry Hole Costs

The Trust depletes its oil and natural gas intangible assets using the unit of production basis by field. 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. Provisions are made for future site restoration based on management's estimation of abandonment requirements using current costs and amortized on a unit of production basis by field.

For the fiscal period ending December 31, 2001, the Trust expensed $1,797,984 for the above-described items.

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.

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 subsidiary Bonterra Energy Corp. (Bonterra Corp.) With the restructuring into an income trust, Bonterra Corp. pays the majority of its income to the Trust through interest and royalty payments which are deductible for income tax purposes. For the period July 1 to December 31, 2001, Bonterra Corp. paid to the Trust sufficient royalty and interest payments to eliminate all of its taxable income. The current tax amount represents adjustments to previous periods tax accruals for Bonterra Corp.

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

Net Earnings

The Trust is extremely pleased to report net earnings of $5,366,202 for its first six months of operations. This represents a return on unit capital of 41.4 percent during the period. The Trust has an average cost for its oil and gas assets of $2.84 per BOE. The low costs that result in low depletion and depreciation and low administration and interest expenses all contribute towards the significant net earnings.

The Trust, effective February 1, 2002, merged with Comstate Resources Income Trust. Due to accounting rules affecting mergers, the oil and gas assets of Comstate Resources Income Trust will be valued at the fair value on the date of merger. As a result, the Trust will have a significantly higher average cost of its oil and gas assets for 2002. However, continued high energy prices should continue to provide the Trust with significant net earnings.

Cash Flow From Operations

Cash flow from operations for the fiscal period ending December 31, 2001 was $6,446,134. The merger with Comstate Resources Income Trust, anticipated operating cost reductions per BOE, increases in oil and natural gas prices, and increases in its production volumes should substantially increase the Trusts 2002 cash flow.

Cash Netback

The following table illustrates the Trust's cash netback:

$ per BOE	$	2001
Production volumes (BOE)		324,893
Gross production revenue	$	36.84
Royalties		(2.19)
Field operating		(12.61)
Field netback		22.04
General and administrative		(0.75)
Management fees		(1.00)
Interest		(0.62)
Cash netback	$	19.67

Comparison to Forecast

	Forecast	Actual	Difference
REVENUE			
Oil and gas sales	$ 6,124,000	$ 5,717,000	$ (407,000)
Royalties	(423,000)	(331,000)	92,000
Other	16,000	51,000	35,000
TOTAL REVENUES	5,717,000	5,437,000	(280,000)
EXPENSES			
Production costs	2,008,000	1,986,000	22,000
Management fee	167,000	151,000	16,000
General and administrative	117,000	123,000	(6,000)
Interest	89,000	108,000	(19,000)
TOTAL EXPENSES	2,381,000	2,368,000	13,000
CASH FLOW FROM OPERATIONS	3,336,000	3,069,000	(267,000)
DEPLETION, DEPRECIATION AND FUTURE SITE RESTORATION	903,000	993,000	(90,000)
FUTURE INCOME TAXES	(213,000)	(110,000)	(103,000)
NET INCOME	$ 2,646,000	$ 2,186,000	$ (460,000)

The forecast figures are the revised forecasted amounts as stated in the Trust's quarterly statements dated September 30, 2001.

Total oil and gas sales were lower than anticipated due primarily to oil prices averaging approximately $10 Cdn. lower than our forecast. However, the Trust somewhat offset the lower oil prices by hedging 80 percent of its crude oil production leaving only 20 percent of its crude oil and its natural gas liquids at spot market prices during the period. In addition natural gas production volumes were below our forecast averaging 1,580 MCF per day compared to forecasted production of 1,801 MCF per day. The 21.7 percent decline in actual royalties from forecast compared to only 6.6 percent decline in revenues was due to the above discussed hedging adjustments as royalties are calculated on well head prices.

Depletion, depreciation and future site restoration was higher due to larger claims on certain of our properties due to reallocation of reserves resulting from our most recent reserve report dated January 1, 2002. Future income tax recovery declined by $103,000 due to lower net income, resulting primarily from revenue being lower than forecast.

Liquidity and Capital Resources

During its first six months of operations, the Trust participated in drilling 10 gross (8.97 net) wells at a total cost of $1,037,085. Of these wells, two (two net) oil wells and two (1.47 net) gas wells were completed and on production by December 31, 2001. Subsequent to year end, three (2.5 net) gas wells drilled during the fiscal period of the Trust and three (three net) gas wells drilled prior to July 1, 2001 were placed on production. Current production from the wells placed on production subsequent to the Trusts fiscal year end is approximately 1,000 MCF per day.

Three (three net) of the wells drilled in the Trusts fiscal period ending December 31, 2001 were not successful in producing from the zones originally drilled for but all have potential to produce coal bed methane. The Trust plans on evaluating the coal bed methane zones during 2002.

At December 31, 2001 the Trust had bank debt of $7,889,737. The Trust's credit facility at year-end consisted of a revolving line of credit of $10,000,000 and carried an interest rate of one quarter percent above Canadian chartered bank prime. The Trust has issued a $1,293,714 letter of credit to the Province of Alberta for future abandonment costs. Due to the outstanding letter of credit, the Trust's available borrowing under the above mentioned facility is $8,706,286. The letter of credit is reduced on a per well basis upon notification of abandonment or reactivation of specified wells.

The credit facility allows for borrowings by means of Bankers Acceptances (BA's). The effective interest rates of BA's are generally half a percentage point lower than that available under the normal credit facility. The Trust attempts to maximize the amount of its credit facility used by financing with BA's to reduce overall interest costs. 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.

At December 31, 2001, the Trust had no stock options issued under its Stock Option Plan. The option plan allowed for 869,223 options to be issued. As a result of the merger with Comstate Resources Income Trust the maximum number of stock options that can be issued has increased to 1,323,450 in 2002 (less than 10 percent of outstanding trust units).

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. The Trust may sometimes elect to protect against price fluctuation by using commodity hedging. The Trust has hedged approximately 60 percent of its current oil and gas production. Please see discussion under revenue and notes to financial statements for details. The Trust 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.

Sensitivity Analysis

Sensitivity analysis, which includes the impact of the February 1, 2002 merger with Comstate Resources Income Trust, as estimated for 2002 follow:

	Cash Flow	Cash Flow Per Unit
U.S. $1.00 per barrel	$1,136,000	$0.085
Canadian $0.10 per MCF	$ 170,000	$0.013
Change of Canadian $0.01/U.S. $ exchange rate	$ 377,000	$0.028

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 shareholders 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

Garth E. Schultz
Vice President, Finance

Auditors' Report

To the Unitholders of Bonterra Energy Income Trust:

We have audited the balance sheet of Bonterra Energy Income Trust as at December 31, 2001 and the statements of unitholders' equity, operations and accumulated income, cash available for distribution, and of cash flows for the period from formation, May 15, 2001, to December 31, 2001. 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 audit.

We conducted our audit 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 financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2001 and the results of its operations and its cash flow for the period from formation, May 15, 2001, to December 31, 2001 in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Calgary, Alberta
March 22, 2002

Chartered Accountants ("Deloitte & Touche LLP")

Consolidated Balance Sheet

As at December 31, 2001 (See Note 1)

Assets

	$	2001
Current		
Accounts receivable	$	2,670,899
Inventories		63,367
Prepaid expenses		354,538
		3,088,804
Property and equipment (Note 3)		
Petroleum and natural gas properties and related equipment		28,909,019
Accumulated depletion and depreciation		(5,845,831)
		23,063,188
	$	26,151,992
Liabilities		
Current		
Bank indebtedness	$	448,039
Distributions payable		956,144
Accounts payable and accrued liabilities		2,572,360
		3,976,543
Long-term debt (Note 4)		7,889,737
Future income tax liability (Note 6)		447,092
Future site restoration		2,450,520
		14,763,892
Unitholders' Equity		
Unit capital (Note 5)		12,975,678
Accumulated income		5,366,202
Accumulated cash distributions		(6,953,780)
		11,388,100
	$	26,151,992

On behalf of the Board:

Director ("George F. Fink")

Director ("F.W. Woodward")

Consolidated Statement of Unitholders' Equity

For the Six Months Ended December 31, 2001 (See Note 1)	$	2001
Unitholders' equity, beginning of period (Note 1)	$	12,975,678
Net earnings for the period		5,366,202
Cash distributions		(6,953,780)
Unitholders' Equity, End of Period	$	11,388,100

Consolidated Statement of Operations And Accumulated Income

For the Six Months Ended December 31, 2001 (See Note 1)		
Revenue	$	2001
Oil and gas sales, net of royalties of $712,323	$	11,257,362
Production costs		(4,097,781)
Alberta royalty tax credits		34,877
Interest and other		14,768
		7,209,226
Expenses		
General and administrative		244,803
Management fees		323,500
Interest on long-term debt		200,307
		768,610
Cash Flow From Operations Before Current Taxes		6,440,616
Gain on disposal of property		294,206
Depletion, depreciation and future site restoration		(1,797,984)
Dry holes		(4,151)
		(1,507,929)
Earnings Before Taxes		4,932,687
Income taxes (recovery) (Note 6)		
Current		(5,518)
Future		(427,997)
		(433,515)
Net Earnings for the Period	$	5,366,202
Accumulatd income at beginning of period		–
Accumulated Income at End of Period	$	5,366,202
Net Earnings Per Unit, Basic and Diluted (Note 2)	$	0.62

Consolidated Statement of Cash Available For Distribution

For the Six Months Ended December 31, 2001 (See Note 1)	$	2001
Cash flow from operations	$	6,446,134
Cash provided by increase in long-term debt		863,274
Cash required for investing activities		(387,085)
Cash provided by working capital adjustments		31,457
Cash Distributions to Unitholders		6,953,780
Cash Distributions Per Unit, Basic and Diluted	$	0.80

Consolidated Statement of Cash Flows

For the Six Months Ended December 31, 2001 (See Note 1)

Operating Activities	$	2001
Net earnings for the period	$	5,366,202
Items not affecting cash		
Gain on sale of property		(294,206)
Depletion, depreciation and future site restoration		1,797,984
Dry holes		4,151
Future income taxes		(427,997)
Cash Flow from Operations		6,446,134
Change in non-cash operating working capital items		(1,372,726)
		5,073,408
Financing Activities		
Increase in long-term debt		863,274
Unit distributions		(5,997,636)
		(5,134,362)
Investing Activities		
Property and equipment expenditures		(1,037,085)
Cash received on disposition of property		650,000
		(387,085)
Net cash inflow (outflow)		(448,039)
Bank indebtedness, beginning of period		–
Bank Indebtedness, End of Period	$	(448,039)

Notes To The Consolidated Financial Statements

Six Months Ended December 31, 2001 (See Note 1)

1. COMMENCEMENT OF TRUST

Bonterra Energy Income Trust was formed on May 15, 2001 to effect the arrangement under the Business Corporations Act (Alberta) involving the exchange of the common shares of Bonterra Energy Corp. on a four-for-one basis for units of Bonterra Energy Income Trust. The shareholders of Bonterra Energy Corp. approved the arrangement on June 27, 2001 and Bonterra Energy Income Trust commenced operations on July 1, 2001. The financial statements represent operating results for the six month period July 1, 2001 to December 31, 2001. The arrangement is accounted for as a continuation through a restructuring of Bonterra Energy Corp. As a result, the carrying values (see below) of the assets and liabilities of Bonterra Energy Corp. are unaffected by the transaction.

Net Assets Acquired

Current Assets	$ 3,633,688
Property and Equipment	23,488,303
	27,121,991
Current Liabilities	(4,158,064)
Long-term Debt	(7,026,463)
Future Income Taxes	(877,857)
Future Site Restoration	(2,083,929)
	$ 12,975,678

2. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

These consolidated financial statements include the accounts of the Trust and its wholly owned subsidiary Bonterra Energy Corp. for the six months ended December 31, 2001.

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. When property is found to contain proved reserves as determined by the Trusts 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

The Trust follows the liability method of accounting for income taxes under which the income tax provision is based on the temporary differences in the accounts calculated using income tax rates expected to apply in the year in which the temporary differences will reverse.

Future Site Restoration

The Trust provides for future site restoration and abandonment costs 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 is included with depletion, depreciation and future site restoration.

Trust Unit-based Compensation Plan

The Trust has a trust-unit-based compensation plan as described in Note 5. No compensation expense is recognized for the plan when trust units or options are issued. Consideration paid on exercise of options is credited to unit capital.

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.

Inventories

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

Net Earnings Per Unit

The Trust uses the treasury stock method of calculating earnings per unit and funds from operations per unit in accordance with the new CICA Handbook Section 3500. Net earnings per unit is calculated using the weighted average number of trust units outstanding during the period, which was 8,692,226. There are no dilutive instruments outstanding as of December 31, 2001 or during the period then ended.

3. PROPERTY AND EQUIPMENT

	Cost	Accumulated Depletion and Depreciation
Undeveloped Land	$ 461,215	$ –
Petroleum and natural gas properties		
and related equipment	28,422,237	5,834,969
Furniture, equipment and other	25,567	10,862
	$ 28,909,019	$ 5,845,831

During the period no general and administrative expenses were capitalized.

4. LONG-TERM DEBT

The Trust has a long-term bank revolving credit facility of $10,000,000 at December 31, 2001. 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. The credit facility carries an interest rate of one-quarter percent above Canadian chartered bank prime. Cash interest paid during 2001 for this loan was $182,858.

The Trust is required under Province of Alberta Regulations to provide a letter of credit in the amount of $1,293,714 to the Alberta Energy and Utilities Board for the future abandonment of specified inactive wells. The letter of credit is reduced on a per well basis if a well is reactivated or abandoned and the surface reclaimed.

5. UNIT CAPITAL

Authorized

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

Issued	Number	Amount
Trust Units		
Balance, beginning of period (Note 1)	8,692,226	$12,975,678
Balance, end of period	8,692,226	$12,975,678

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 869,223 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. As of December 31, 2001 no options have been issued.

6. INCOME TAXES

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

Temporary differences related to assets and liabilities	$	723,315
Finance expense charged to unitholders' equity		(103,263)
Tax loss carry forward		(172,960)
	$	447,092

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

Earnings before income taxes	$	4,932,687
Combined federal and provincial income tax rates		43.26%
Income tax provision calculated using statutory tax rates		2,133,880
Increase (decrease) in income taxes resulting from:		
Non-deductible crown royalties		293,072
Resource allowance		(746,038)
Trust income allocated to unitholders		(1,991,107)
Non-taxable gain on disposal of property		(127,763)
Other		4,441
	$	(433,515)

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 Draw down %	Amount
Undepreciated capital costs	20-100	$ 3,166,070
Canadian oil and gas property expenses	10	15,221,575
Canadian exploration expenses	100	703,929
Tax loss	100	399,772
Finance expenses	20	238,681
		$19,730,027

7. FINANCIAL INSTRUMENTS

The carrying value of the financial instruments of the Trust approximates their estimated fair values. Financial instruments include accounts receivable, accounts payable and accrued liabilities, distributions payable, and long-term debt.

8. COMMITMENTS - FUTURE SALES AGREEMENTS

The Trust entered into the following commodity hedging transactions in 2001 for a portion of its 2002 production:

Period of Agreement	Commodity	Volume per day	Index	Price (Cdn.)
January 1 to January 31, 2002	Crude Oil	1,200 barrels	WTI	$42 per barrel
February 1 to February 28, 2002	Crude Oil	800 barrels	WTI	$42 per barrel

9. MANAGEMENT AGREEMENT

The Trust has entered into a management agreement with Comstate Resources Ltd. (Comstate), a company with common management, to provide field operations, management and general office services. Fees charged for field operations are charged on a per well basis. Total amount charged during the period was $394,020. This amount, net of amounts related to joint venture partner interests, has been recorded in production costs.

Fees for management and general office services consist of $30,000 per month plus three percent of before tax net income. Total amount paid during the period was $326,230 and has been included in general and administrative expenses.

Effective February 1, 2002, Comstate became a wholly owned subsidiary of the Trust and the Trust is no longer charged a management fee.

10. SUBSEQUENT EVENT - MERGER

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 will be accounted for as a reverse takeover of Comstate Trust by the Trust as the former unitholders of the Trust will own greater than 50% of the units of the new trust. This 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 is to be accounted for as a reverse takeover, the assets and liabilities of the Trust will remain at their book values, while the assets and liabilities of Comstate Trust will be recorded at their fair values on January 31, 2002. The net assets of Comstate Trust acquired through this merger transaction are as follows:

Net working capital	$ 413,372
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

11. SUBSEQUENT EVENT- COMMITMENTS

The Trust entered into the following commodity hedging transactions subsequent to December 31, 2001 for a portion of its future production:

Period of Agreement	Commodity	Volume per day	Index	Price (Cdn.)
April 1, 2002 to October 31, 2003	Natural Gas	1,000GJ's	AECO	$3.77 per GJ
May 1, 2002 to October 31, 2002	Natural Gas	625GJ's	AECO	$4.30 per GJ
April 1, 2002 to December 31, 2002	Crude Oil	600 barrels	WTI	$37.97 per barrel

Corporate Information

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F. W. Woodward, Calgary, Alberta

Officers

G.F. Fink – President

R.M. Jarock – Operations Manager & Vice President, Acquisitions

S.L. Safronovitch – Vice President Operations

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

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Bankers

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Stock Listing

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