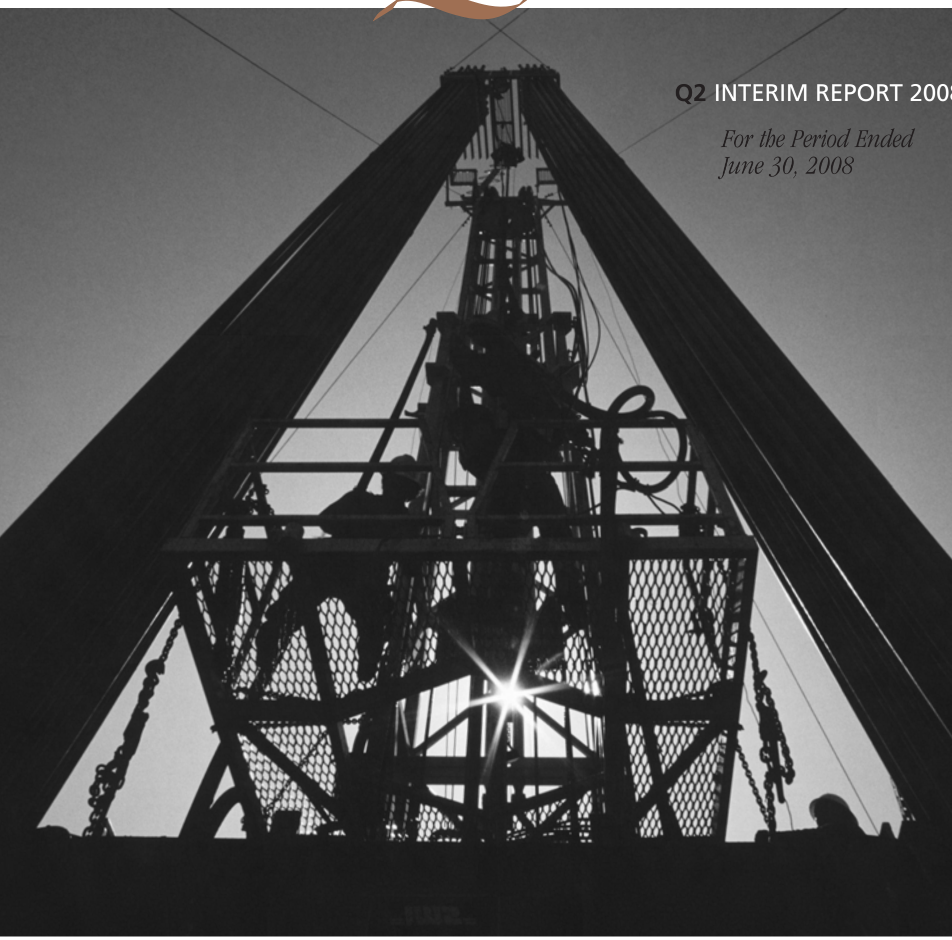
Bonterra
Energy Income Trust



Q2 INTERIM REPORT 2008

For the Period Ended
June 30, 2008

Highlights

	Three Months Ended June 30		Six Months Ended June 30	
	2008	2007	**2008**	2007
Financial ($000, except $ per unit)				
Revenue – realized oil and gas	**34,398**	23,462	**64,891**	46,064
Adjusted Distribution Base (1)	**21,352**	11,695	**39,410**	24,824
Per Unit – Basic	**1.25**	0.69	**2.32**	1.47
Per Unit – Diluted	**1.24**	0.69	**2.31**	1.47
Cash Distributions per Unit	**0.84**	0.66	**1.54**	1.32
Payout Ratio	**67%**	96%	**67%**	90%
Net Earnings	**12,912**	5,371	**23,716**	13,033
Per Unit – Basic	**0.76**	0.32	**1.40**	0.77
Per Unit – Diluted	**0.75**	0.32	**1.39**	0.77
Capital Expenditures and Acquisitions	**2,543**	1,699	**8,964**	9,324
Total Assets			**153,247**	139,432
Working Capital Deficiency (2)			**57,148**	49,595
Unitholders' Equity			**46,612**	51,920
Operations				
Oil and NGL's				
Barrels per Day	**3,024**	3,074	**3,088**	3,150
Average Price ($ per barrel)	**101.69**	67.60	**94.31**	65.02
Natural Gas				
MCF per Day	**7,272**	6,663	**7,206**	6,567
Average Price ($ per MCF)	**9.61**	7.40	**8.97**	7.46
Total Barrels Per Day (3)	**4,236**	4,185	**4,289**	4,245

(1) Adjusted distribution base is not a recognized measure under GAAP. Management believes that in addition to cash flow from operations, adjusted distribution base is a useful supplemental measure as it demonstrates the Trust's ability to generate the funds necessary to make trust distributions, repay debt or fund future growth through capital investment. Investors are cautioned, however, that this measure should not be construed as an indication of the Trust's performance. The Trust's method of calculating this measure may differ from other issuers and accordingly, it may not be comparable to that used by other issuers. For these purposes, the Trust defines adjusted distribution base as funds provided by operations before changes in non-cash operating working capital items excluding gain on sale of property and asset retirement expenditures.

The Canadian Institute of Chartered Accountants (CICA) published recommendations regarding disclosure of a measure called Standardized Distributable Cash. Please refer to page 9 of this report for the reconciliation between adjusted distribution base and standardized distributable cash.

(2) Includes 100 percent of debt.

(3) 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.

Report to Unitholders

Bonterra Energy Income Trust (Bonterra or the trust) is pleased to report the operating and financial results for the three months and six months ended June 30, 2008. During the quarter, the trust once again realized several new milestones on the heels of a record-setting first quarter mainly due to the sustained strength in both crude oil and natural gas prices, relatively stable production levels and cost controls.

Key successes included:

- Record-level revenue from oil and gas sales during the second quarter of 2008 of approximately $34.4 million, a 12 percent increase over the previous quarter and a 47 percent increase over second quarter 2007.
- Net earnings increased 140 percent to an all-time high of approximately $12.9 million in the second quarter of 2008 compared to $5.4 million in the second quarter of 2007. Net earnings also increased 20 percent quarter over quarter.
- Bonterra's adjusted distribution base was approximately $21.4 million, an increase of 18 percent over first quarter 2008 and 83 percent over second quarter 2007.
- Cash distributions to unitholders increased to $0.84 per unit during the quarter compared to $0.66 in the second quarter of 2007; a payout ratio of 67 percent in 2008 compared to 96 percent in 2007. Subsequent to the quarter end, Bonterra increased the distribution to $0.32 per trust unit for both the July and August payments. This represents the fourth increase during 2008. The January, 2008 distribution was $0.22 per unit.

The continued strength in crude oil and natural gas prices can be seen in Bonterra's average realized price of $101.69 per barrel for oil and natural gas liquids and $9.61 per mcf for natural gas during the second quarter of 2008. This represents an increase of 50 percent and 30 percent, respectively, when compared with the second quarter of 2007.

As a result, Bonterra's cash netbacks also increased to a record level of $55.34 per barrel of oil equivalent (boe) in the second quarter of 2008 compared to $45.67 per boe in the first quarter of 2008 and $32.09 in the second quarter of 2007. The increased netbacks were mainly a result of the aforementioned strength in commodity prices which more than offset increased royalty expense and a higher realized loss on risk management contracts during the quarter.

Bonterra's exposure to the higher prices was offset somewhat by its risk management program. Bonterra has entered into commodity hedging contracts on approximately 28 percent of its 2008 production. Realized risk management losses for the first six months of 2008 were approximately $5.4 million. The risk management contracts will all expire on December 31, 2008. In light of the exceptionally strong prices Bonterra is receiving for production coupled with the reduction in the payout ratio, management and the board of directors have reassessed the hedging policy and decided that in the near term the Trust will not enter into further risk management strategies.

Bonterra intends to continue providing superior value to unitholders by paying stable, or when appropriate increase or decrease distributions while executing a conservative and targeted development program. Bonterra's current distribution level of $0.32 per trust unit is expected to be sustainable as long as prices average Cdn $115 per barrel of crude oil and Cdn $9.50 per mcf of natural gas and production is sustained at a rate of approximately 4,450 boe per day.

As the Trust produces its oil and gas assets, it is essential to invest capital to not only offset natural production declines but grow production and reserves. Bonterra's decline rate is among the lowest in the energy trust sector. This not only highlights the top-quality nature of the asset base but also allows the Trust to spend less capital to replace or increase production while paying out a higher portion of its adjusted distribution base.

Daily production decreased slightly in the second quarter of 2008 to 4,236 boe per day when compared to first quarter 2008 levels of 4,343 boe per day. Production levels have been historically lower for the Trust in the second quarter versus the first quarter each year. This is mainly due to over 85 percent of wells having restricted access during second quarters due to spring break-up and restricted road access. During the quarter, Bonterra was unable to complete wells, tie-ins and timely repairs which negatively impacted production. In addition, the operator of a natural gas plant where 40 percent of the Trust's Pembina production is processed conducted their annual turnaround during the month of May resulting in approximately 300 mcf per day of natural gas being shut-in.

However, this did represent a slight increase when compared to the second quarter of 2007 where 4,185 boe per day was recorded. For the first six months of 2008, the trust incurred capital expenditures of approximately 8.5 million on its development program.

Key activities included drilling:

- 10 Cardium oil wells (8.1 net) and 1 shallow gas well (0.1 net) on operated lands; and
- 3 Cardium wells (0.4 net) on non-operated lands;

The Trust's success rate is 100 percent on its 2008 drilling program. In addition, 16 Cardium wells and 2 natural gas wells were tied-in during the first half of the year. The remaining 4 Cardium oil wells were tied in subsequent to quarter-end. The final natural gas well is expected to be completed and tied in prior to the end of the third quarter this year.

In view of the higher commodity price environment and current expectations, the Board of Directors has deemed it appropriate to increase the full year capital budget by 25 percent to $25 million. Bonterra's development program is typically most active with the commencement of its summer drill program. The balance of this year's program is expected to begin in the third week of August and include drilling 17 Cardium wells (approximately 14.5 net) prior to year-end and 3 to 5 shallow gas wells.

Bonterra has historically grown production and reserves by developing its own properties rather than through acquisitions. However, Bonterra's conservative capital structure and strong balance sheet positions the Trust to capitalize on any future opportunities should they arise.

In the second quarter of 2008, the Trust's net debt as a percentage of annualized adjusted distribution base was approximately eight months. Management and the Board are of the opinion that by limiting debt levels to approximately one year adjusted distribution base or less, the Trust will be well-situated to make strategic acquisitions. In addition, this provides Bonterra with the flexibility to fund its development program from cash flow, the exercise of employee trust unit options and additional bank loans if need be without having to issue further equity.

Bonterra will continue to assess all future acquisition opportunities. As well, the Trust is continuing to evaluate the options available to it in response to the federal government's legislation change to the taxation of Canadian trusts. The Board and management are currently considering whether to continue as a trust until the end of 2010 when the tax structure will change or whether there may be advantages in converting its structure earlier. Bonterra expects to have greater clarity regarding a longer-term solution within the year.

We wish to thank both the Board of Directors and staff for their efforts and hard work during the first half of the year. The record-level operating and financial results recorded would not be possible without a unified and focused effort. As the Trust moves into the second half of 2008, it will continue to execute the long-term strategy to maximize unitholder returns through prudent financial management while conservatively growing the Trust with a targeted exploitation and development program.

George F. Fink
President, CEO and Director
August 11, 2008

The following report dated August 11, 2008 is a review of the operations and current financial position for Bonterra Energy Income Trust ("Bonterra" or "the Trust") and should be read in conjunction with the unaudited financial statements for the six months ended June 30, 2008, including the notes related thereto, and the audited financial statements for the fiscal year ended December 31, 2007, together with the notes related thereto.

Forward-looking Information

Certain statements contained in this MD&A include statements which contain words such as "anticipate", "could", "should", "expect", "seek", "may", "intend", "likely", "will", "believe" and similar expressions, relating to matters that are not historical facts, and such statements of our beliefs, intentions and expectations about development, results and events which will or may occur in the future, constitute "forward-looking information" within the meaning of applicable Canadian securities legislation and are based on certain assumptions and analysis made by us derived from our experience and perceptions. Forward-looking information in this MD&A includes, but is not limited to: expected cash provided by continuing operations; cash distributions; future capital expenditures, including the amount and nature thereof; oil and natural gas prices and demand; expansion and other development trends of the oil and gas industry; business strategy and outlook; expansion and growth of our business and operations; and maintenance of existing customer, supplier and partner relationships; supply channels; accounting policies; credit risks; and other such matters.

All such forward-looking information is based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions and expected future developments, as well as other factors we believe are appropriate in the circumstances. The risks, uncertainties, and assumptions are difficult to predict and may affect operations, and may include, without limitation: foreign exchange fluctuations; equipment and labour shortages and inflationary costs; general economic conditions; industry conditions; changes in applicable environmental, taxation and other laws and regulations as well as how such laws and regulations are interpreted and enforced; the ability of oil and natural gas trusts to raise capital; the effect of weather conditions on operations and facilities; the existence of operating risks; volatility of oil and natural gas prices; oil and gas product supply and demand; risks inherent in the ability to generate sufficient cash flow from operations to meet current and future obligations; increased competition; stock market volatility;

opportunities available to or pursued by us; and other factors, many of which are beyond our control.

Actual results, performance or achievements could differ materially from those expressed in, or implied by, this forward-looking information and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking information will transpire or occur, or if any of them do, what benefits will be derived there from. Except as required by law, Bonterra disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

The forward-looking information contained herein is expressly qualified by this cautionary statement.

Financial and Operational Discussion

Quarterly Comparisons

	2008		2007			
	2nd	1st	4th	3rd	2nd	1st
Financial ($000 except $ per unit)						
Revenue – realized oil and gas sales	**34,398**	30,493	26,573	23,794	23,462	22,602
Adjusted Distribution Base [1]	**21,352**	18,058	15,842	13,149	11,695	13,129
Per Unit Basic	**1.25**	1.07	0.94	0.78	0.69	0.78
Per Unit Fully Diluted	**1.24**	1.06	0.94	0.77	0.69	0.78
Cash Distributions	**0.84**	0.70	0.66	0.66	0.66	0.66
Payout Ratio	**67%**	66%	70%	85%	96%	85%
Net Earnings [2]	**12,912**	10,804	8,372	8,945	5,371	7,662
Per Unit Basic [2]	**0.76**	0.64	0.49	0.53	0.32	0.45
Per Unit Fully Diluted [2]	**0.75**	0.64	0.49	0.53	0.32	0.45
Capital Expenditures & Acquisitions	**2,543**	6,421	7,213	2,763	1,699	7,625
Total Assets	**153,247**	150,169	143,239	138,140	139,432	140,926
Working Capital Deficiency	**57,148**	57,810	58,766	50,041	49,595	49,288
Unitholders' Equity	**46,612**	48,136	44,218	50,820	51,920	57,646
Operations						
Oil and Liquids (barrels per day)	**3,024**	3,153	3,098	3,054	3,074	3,227
Natural Gas (MCF per day)	**7,272**	7,139	7,176	6,196	6,663	6,470
Total BOE per day	**4,236**	4,343	4,295	4,086	4,184	4,305

(2) All four quarters of 2007 have been amended to remove the use of hedge accounting as of the beginning of the year. Net earnings for the year 2007 have not changed.

	2006			
	4th	3rd	2nd	1st
Financial ($000, except $ per unit)				
Revenue – realized oil and gas sales	21,719	23,665	23,219	20,131
Adjusted Distribution Base (1)	12,235	14,401	14,008	12,153
Per Unit Basic	0.72	0.86	0.84	0.73
Per Unit Fully Diluted	0.72	0.85	0.83	0.72
Cash Distributions	0.72	0.72	0.69	0.69
Payout Ratio	100%	84%	82%	95%
Net Earnings	6,471	10,441	10,617	9,721
Per Unit Basic	0.39	0.62	0.64	0.58
Per Unit Fully Diluted	0.38	0.62	0.63	0.58
Capital Expenditures and Acquisitions	9,457	12,597	6,246	10,048
Total Assets	134,942	130,655	122,166	118,439
Working Capital Deficiency	50,187	38,853	28,820	25,532
Unitholders' Equity	53,359	60,387	61,202	61,365
Operations				
Oil and Liquids (barrels per day)	3,138	3,024	3,001	2,996
Natural Gas (MCF per day)	5,885	5,925	6,181	6,071
Total BOE per day	4,119	4,012	4,031	4,008

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Production

	Three months ended			Six months ended	
	June 30, 2008	Mar 31, 2008	June 30, 2007	**June 30, 2008**	June 30, 2007
Crude oil and NGLs (barrels per day)	**3,024**	3,153	3,074	**3,088**	3,150
Natural gas (MCF per day)	**7,272**	7,139	6,663	**7,206**	6,567
Total BOE's per day	**4,236**	4,343	4,185	**4,289**	4,245

Barrels of oil equivalent (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.

Production volumes for the second quarter were affected primarily by two factors. Firstly, spring breakup prevented timely repairs on the Trust's producing wells. This is a normal occurrence as over 85 percent of the Trust's wells have restricted access during the second quarter of each year. Secondly, the operator of a natural gas plant where approximately 40 percent of the Trust's Pembina production gets processed conducted their annual turnaround during the month of May resulting in an average of approximately 300 MCF per day (50 BOE per day for the month of May) of natural gas being shut-in.

The Trust drilled 10 gross (8.1 net) Cardium oil wells and 1 gross (.1 net) shallow gas well in the first six months of 2008 on its operated lands. In addition the Trust participated in the drilling of 3 (.4 net) Cardium wells on non-operated lands. As at June 30, 2008, Bonterra had 4 gross (4 net) Cardium oil wells and 1 gross (.1 net) natural gas wells and 3 gross (2.5 net) coalbed methane wells (CBM) drilled but not on production. During the first six months of 2008, the Trust tied-in 16 gross (10.8 net) Cardium wells and 2 gross (2 net) natural gas wells. The Trust completed and tied in the remaining Cardium oil wells in July. The natural gas well is anticipated to be completed and tied-in prior to the end of the third quarter.

It is currently expected that the summer drill program will commence during the third week of August. It is anticipated that a total of 17 gross, approximately 14.5 net, Cardium wells will be drilled prior to December 31. Bonterra is also pursuing the possible drilling of 3 to 5 shallow gas wells in 2008. Based on current expectations the Trust is increasing its 2008 capital drilling budget by $5,000,000 to $25,000,000.

Revenue

	Three months ended			Six months ended	
(Cdn $)	**June 30, 2008**	Mar 31, 2008	June 30, 2007	**June 30, 2008**	June 30, 2007
Revenue – oil and gas sales (000's)	**34,398**	30,493	23,462	**64,891**	46,064
Average Realized Prices:					
Crude oil and NGLs (per barrel)	**101.69**	87.20	67.60	**94.31**	65.02
Natural gas (per MCF)	**9.61**	8.32	7.40	**8.97**	7.46

Second quarter realized gross revenue of $34,398,000 was the highest single quarter revenue ever recorded by the Trust. The increase in revenue over prior periods was primarily due to higher commodity prices. Included in revenue is a realized loss on risk management contracts of $5,381,000 for the first six months of 2008 ($815,000 gain in the first six months of 2007). In addition, the Trust also recorded an unrealized loss on risk management contracts of $7,025,000 for the first six months of 2008 (first six months of 2007 - $439,000). All fair value adjustments related to outstanding risk management contracts are recorded as adjustments to net earnings.

During the first quarter of 2008, the Trust reassessed its hedging policy. With the disposal of the Trust's interest in the Dodsland properties, which had production volume of approximately one barrel per day per well and operating costs per barrel in the mid $30's, as well as the reduction in the payout ratio from the high 80 percent to mid 60 percent range, Bonterra has decided that at least in the near term it will not enter into further risk management contracts. The Trust will however maintain the existing risk management agreements until they expire. Kindly refer to Note 10 to the attached interim financial statements for details of outstanding risk management contracts. As at June 30, 2008, the fair value of the outstanding risk management contracts was a net liability of $10,109,000 (December 31, 2007 – $3,085,000).

Royalties

	Three months ended			Six months ended	
($000)	**June 30, 2008**	Mar 31, 2008	June 30, 2007	**June 30, 2008**	June 30, 2007
Crown royalties	**4,263**	3,613	2,389	**7,876**	4,545
Freehold royalties, gross overriding royalties and net carried interests	**1,056**	731	1,479	**1,787**	1,901
Total royalty expense	**5,319**	4,344	3,868	**9,663**	6,446

Royalties paid by the Trust consist primarily of Crown royalties paid to the Provinces of Alberta and Saskatchewan. The non-Crown royalty figure for the six months ended June 30, 2007 includes a prior year royalty charge adjustment of $800,000.

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 11.2 percent (2007 – 10 percent) and approximately 2.5 percent (2007 – 2.5 percent) for other royalties before hedging adjustments. Bonterra continues to expect an average combined royalty rate of approximately 13.5 percent for the balance of 2008.

The recently announced Alberta royalty amendments will result in a higher average royalty rate for Bonterra in 2009 and beyond. The Trust currently estimates that the new legislation will increase the average Crown royalty rate by between 4 to 6 percent (15-17 percent of gross revenues). The new royalty rates vary by prices as well as productivity levels.

Production Costs

	Three months ended			Six months ended	
	June 30,	Mar 31,	June 30,	**June 30,**	June 30,
($000)	**2008**	2008	2007	**2008**	2007
Production costs	**6,089**	6,317	6,556	**12,406**	12,137
$ per BOE	**15.79**	15.98	17.21	**15.89**	15.80

Continued high commodity prices have resulted in service cost increases in the 5 to 10 percent range on a year over year basis. The Trust continues to monitor costs as best it can, but given the high commodity price environment, it expects costs per BOE to remain in the $15.50 to $16.00 range for the remainder of 2008.

The Trust's production comes primarily from low productivity wells. These wells generally result in higher production costs on a per unit-of-production basis as costs such as municipal taxes, surface leases, power and personnel costs are not variable with production volumes. The high production costs for the Trust are substantially offset by current low royalty rates of approximately 13.5 percent, which is much lower than industry average for conventional production and results in high cash netbacks on a combined basis despite higher than industry average production costs.

General and Administrative Expenses

	Three months ended			Six months ended	
	June 30,	Mar 31,	June 30,	**June 30,**	June 30,
($000)	**2008**	2008	2007	**2008**	2007
G&A Expense	**855**	877	527	**1,732**	1,091
$ per BOE	**2.22**	2.22	1.42	**2.22**	1.44

The increase in G&A expense year over year was due to increased employee compensation of approximately $575,000 as well as increases in other professional service costs of approximately $100,000. Offsetting a portion of the increase was increased cost recoveries of $26,000 from related corporations (see Related Party section).

Interest Expense

	Three months ended			Six months ended	
	June 30,	Mar 31,	June 30,	**June 30,**	June 30,
($000)	**2008**	2008	2007	**2008**	2007
Interest Expense	**650**	799	744	**1,449**	1,441

Increases in average outstanding debt balances in 2008 over 2007 amounts were offset by an approximately one percent drop in borrowing rates. The quarter over quarter decrease was due to slightly lower interest rates as well as reduced debt balances. Increased cash flow resulting from record crude oil prices coupled with the Trust's lower payout ratio resulted in a reduction of approximately $6,000,000 in the Trust's debt in Q2 from Q1 2008. With spring breakup during the second quarter, restricting Bonterra's capital programs, and continuing record commodity prices the Trust anticipates reduced debt levels for the third quarter of 2008 increasing thereafter as the Trust continues with its fall and winter drill programs. Bonterra is currently able to borrow at rates between 4.35 and 4.75 percent per annum.

The Trust's net debt as a percentage of annualized second quarter adjusted distribution base was approximately eight months (67 percent). The Trust believes that maintaining debt at or less than one year's adjusted distribution base (calculated quarterly based on annualized quarterly results) is an appropriate level to either take advantage of future acquisition opportunities or provide flexibility to develop its infill oil, shallow gas and CBM potential from its cash flow and additional bank loans. Thus, it should not be necessary to issue additional trust units.

Unit Based Compensation

Unit based compensation is a statistically calculated value representing the estimated expense of issuing employee unit options. The Trust records a compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants. During the quarter 29,000 employee unit options were issued with an estimated fair value of $115,000 ($3.95 per option) using the Black-Scholes pricing model. If no further options are issued approximately $548,000 of compensation expense will be expensed during the remainder of 2008, 2009 and 2010.

Depletion, Depreciation, Accretion 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.

Provision for depletion, depreciation and accretion was $7,010,000 and $6,786,000, respectively for the six month periods ending June 30, 2008 and June 30, 2007. The increase in the depletion amount was due primarily to increased production volumes and a marginal increase in the average cost of reserves.

The Trust continues to replace production declines with reserves from newly drilled wells. The Trust has capital costs of approximately $6.10 per proved BOE of reserves based on the December 31, 2007 independent engineering report.

All wells drilled during the fourth quarter of 2007 and first half of 2008 have been successful and therefore no dry hole costs were recorded during 2008.

Taxes

On October 31, 2006, the Canadian Federal Government announced a proposed Trust taxation pertaining to taxation of distributions paid by publicly traded income trusts. This was enacted by legislation in June 2007. Currently distributions paid to Unitholders, other than return of capital, are claimed as a deduction by the Trust in arriving at taxable income whereby tax is eliminated at the Trust level and is paid by the Unitholders. The June, 2007 legislation results in a two-tiered tax structure whereby distributions commencing in 2011 would first be subject to a 31.5 percent tax at the Trust level and then investors would be subject to tax on the distribution as if it were a taxable dividend paid by a taxable Canadian corporation. The tax rate was subsequently lowered to 29.5 percent in 2011 and 28 percent in 2012 and thereafter.

On February 26, 2008, the Minister of Finance announced that instead of basing the provincial component of the trust tax rate on a flat rate of 13 percent, the provincial component will instead be based on the general provincial corporate tax rate in each province in which the income trust has a permanent establishment. Under the proposal the Trust would be considered to have a permanent establishment in Alberta, where the provincial tax rate in 2011 is expected to be 10 percent. This would result in an overall tax rate to the Trust of 26.5 percent in 2011 and 25 percent thereafter.

Future income tax expense for the first six months of 2008 decreased by $2,590,000 compared to the first six months of 2007. Until June 2007, the Trust had been tax effecting the reversal of taxable temporary differences at a nil tax rate on the assumption that the Trust would make sufficient tax deductible cash distributions to Unitholders such that the Trust's taxable income would be nil for the foreseeable future and the tax burden would have continued to be with whomever received the monthly distribution. The new legislation limits the tax deductibility of cash distributions such that income taxes may become payable in the future. This resulted in a one-time adjustment to 2007's future income tax expense of approximately $3.8 million.

The Trust has estimated its future income taxes based on its best estimates of results from operations and tax pool claims and cash distributions in the future assuming no material change to the Trust's current organizational structure. As currently interpreted, Canadian Generally Accepted Accounting Principles (GAAP) does not permit the Trust's estimate of future income taxes to incorporate any assumptions related to a change in organizational structure until such structures are given legal approval.

The Trust's estimate of its future income taxes will vary as to the Trust's assumptions pertaining to the factors described above and such variations may be material.

Until 2011, the new legislation does not directly affect the Trust's cash flow from operations, and accordingly, the Trust's financial condition.

Currently, taxable income earned within the Trust is required to be allocated to its Unitholders and as such the Trust will not incur any current taxes. However, the Trust operates its oil and gas interests through its 100 percent owned subsidiaries Bonterra Energy Corp. (Bonterra Corp.) and Novitas Energy Ltd. (Novitas) and these corporations may periodically be taxable.

These corporations pay the majority of their income to the Trust through interest and royalty payments which are deductible for income tax purposes. The current tax provision relates to a resource surcharge payable by the Trust's subsidiaries to the Province of Saskatchewan. The surcharge is calculated as a flat percent of revenues generated from the sale of petroleum products produced in Saskatchewan. The provincial government of Saskatchewan has reduced the resource surcharge rate to 3.1 percent on July 1, 2007 and to 3.0 percent on July 1, 2008.

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

($000)	Rate of Utilization %	Amount
Undepreciated capital costs	20-100	16,899
Canadian oil and gas property expenditures	10	1,620
Canadian development expenditures	30	30,651
Canadian exploration expenditures	100	93
Income tax losses carried forward (1)	100	7,084
		56,347

(1) Income tax losses carried forward expire in 2026 ($215,000) and 2027 ($6,869,000).

The Trust itself has the following tax pools, which may be used in reducing future taxable income allocated to its Unitholders:

($000)	Rate of Utilization %	Amount
Canadian oil and gas property expenditures	10	13,555
Finance costs	20	195
Eligible capital expenditures	7	336
		14,086

The Canadian taxable portion of distributions for each taxation year is calculated on an annual basis and is reported by February 28 of the following year.

Net Earnings

	Three months ended			Six months ended	
($000)	**June 30, 2008**	Mar 31, 2008	June 30, 2007	**June 30, 2008**	June 30, 2007
Net earnings	**12,912**	10,804	5,371	**23,716**	13,033

Net earnings increased to an all time high of $23,716,000 in the first half of 2008 from $13,033,000 in the corresponding 2007 period. Revenue increases due to increased commodity prices and production were partially offset by increased loss on risk management contracts (both realized and unrealized) as well as increased royalty expense. The Trust's quarter over quarter net earnings increased $2,108,000 due primarily to increased commodity prices.

The Trust continues to return in excess of 35 percent of its gross realized revenues in net earnings. The Trust's low capital costs combined with a low debt to adjusted distribution base ratio all contribute to the high return. Bonterra's higher than industry average per unit operating costs are more than offset with its low royalty rates resulting in one of the highest cash netbacks in the industry (see cash netback).

Comprehensive Income

On January 1, 2007, the Trust adopted the new GAAP accounting standards regarding the accounting for financial instruments. On adoption, the Trust increased its investment in a related party by $1,836,000 for the fair value of this investment. Other comprehensive income for the first half of 2008 included a decrease in the unrealized gain on investment in a related party of $164,000 (2007 increase of $628,000) net of applicable income taxes.

Standardized Distributable Cash

Compliance with Guidance

This Management's, Discussion and Analysis is in all material respects in accordance with the recommendations provided in CICA's publication *Standardized Distributable Cash in Income Trusts and Other Flow-Through Entities: Guidance on Preparation and Disclosure.*

Definition and Disclosure of Standardized Distributable Cash

($000)	**Six Months Ended June 30, 2008**	Six Months Ended June 30, 2007	Cumulative Amounts From Inception of Trust (July 1, 2001) to June 30, 2008
Cash Flow from Operating Activities	**36,742**	26,178	255,017
Less adjustment for:			
Capital expenditures	**(8,964)**	(9,324)	(103,462)
Financing restrictions caused by debt	**–**	–	–
Standardized Distributable Cash	**27,778**	16,854	151,555

Definition and Disclosure of Adjusted Distribution Base (Formerly Funds Flow from Operations)

($000)	**Six Months Ended June 30, 2008**	Six Months Ended June 30, 2007	Cumulative Amounts From Inception of Trust (July 1, 2001) to June 30, 2008
Standardized Distributable Cash – per above	**27,778**	16,854	151,555
Adjusted for:			
Capital expenditures	**8,964**	9,324	103,462
Gain on sale of property	**–**	–	1,089
Changes in accounts receivable	**4,837**	(599)	10,413
Changes in crude oil inventory	**(87)**	(65)	166
Changes in parts inventory	**(11)**	(24)	(201)
Changes in prepaid expenses	**1,058**	454	1,556
Changes in accounts payable and accrued liabilities	**(5,042)**	(1,429)	(3,179)
Asset retirement obligations settled	**1,913**	309	4,442
Adjusted Distribution Base [1]	**39,410**	24,824	269,303

[1] Adjusted distribution base is not a recognized measure under GAAP. The Trust believes that in addition to cash flow from operations the adjusted distribution base is a useful supplemental measure as it demonstrates the Trust's ability to generate the funds necessary to make trust distributions, repay debt or fund future growth through capital investment. Investors are cautioned, however, that this measure should not be construed as an indication of the Trust's performance. The Trust's method of calculating this measure may differ from other issuers and accordingly, it may not be comparable to that used by other issuers. For these purposes, the Trust defines adjusted distribution base as funds provided by operations before changes in non-cash operating working capital items excluding gain on sale of property and asset retirement obligations.

Working Capital Policies

The Trust, excluding current portion of debt, maintains a consistent level of working capital. All items of working capital are generally turned over every 30 to 60 days. Excluding minor variations due to payment of bonuses and property taxes, there are no reoccurring items that would cause a seasonal impact in working capital.

Analysis of Relationship between Standardized Distributable Cash, Distributions, and Investing and Financing Activities

($000)	Six Months Ended June 30, 2008	Year ended December 31, 2007	Year ended December 31, 2006	Year ended December 31, 2005
Standardized Distributable Cash	**27,778**	32,133	14,346	23,413
Distributions [1]	**(26,211)**	(44,648)	(47,281)	(38,949)
Increase (decrease) in bank debt	**(4,442)**	12,043	25,202	11,717
Proceeds on exercise of employee unit options	**4,490**	993	5,161	2,823
Issuance of units (net of costs of issue)	**–**	–	–	(259)
Non-cash financing and investing working capital adjustments	**(1,615)**	(521)	2,572	1,255

[1] Includes the distribution declared in July in respect of June operations and excludes the January distribution as it was in respect of December operations.

The only unfunded operating transaction of the Trust is its asset retirement obligations. The Trust has the following estimated timing of expenditures for asset retirement obligations:

Year	Expected Expenditure ($000)
2008 (including expenditures incurred to date)	2,227
2009	250
2010	175
2011	563
2012	856
	4,071

Definition and History of Productive Capacity and Strategy

Bonterra's primary objective is to continue paying distributions to its Unitholders. This is accomplished by developing and growing its reserves from which cash flow is generated. The Trust defines Productive Capacity Maintenance as the maintaining of the Trust's proven plus probable reserves. The Trust follows a policy of internal development as its primary method of planned growth. Bonterra has a significant inventory of undrilled Cardium oil infill drilling locations as well as several shallow gas opportunities on its lands or through farm-in agreements. It is management's view that the calculation of the amount required for Productive Capacity Maintenance is the amount of reserves produced in the relevant time period multiplied by the Trust's finding and development costs for proven plus probable reserves. For this purpose the Trust believes that the use of a three-year average rate is reasonable given fluctuations in annual costs due to market conditions.

	Six Months Ended June 30, 2008	Year ended December 31, 2007	Year ended December 31, 2006	Year ended December 31, 2005
Proven and probable reserves at beginning of period (BOE's)	**27,320,000**	26,476,000	23,870,000	19,711,000
Reserves added due to acquisitions (BOE's)	**–**	(421,000)	16,000	2,393,000
Reserves added due to capital expenditures (BOE's)	(1)	2,806,000	4,082,000	3,100,000
Production during period (BOE's)	**781,000**	1,540,000	1,476,000	1,334,000
Increase in productive capacity (BOE's)	(1)	845,000	2,606,000	4,159,000
Reserves per unit (fully diluted)	**1.55**[1][2]	1.62	1.57	1.46
Productive capacity maintenance requirements	**$8,642,000**	$17,043,000	$17,472,000	$9,205,000
Capital expenditures for the period	**$8,964,000**	$19,300,000	$38,348,000	$56,703,000
Capital expenditures in excess of maintenance requirements	**$322,000**	$2,257,000	$20,876,000	$47,498,000
Cost of increased productive capacity (per BOE)	(1)	$2.67	$8.01	$11.42

(1) The Trust does not update reserve information quarterly.

(2) Assuming no other additional reserves in 2008.

Financing Strategy

The Trust maintains a strategy of limiting its debt levels to approximately one year adjusted distribution base. Bonterra has a long-term goal to retain between 20 to 25 percent of its adjusted distribution base to finance its capital maintenance expenditures. Over the past years, this level of retention of adjusted distribution base, along with the exercising of unit options and modest increases in its bank loans has proven to be sufficient to maintain the productive capacity of the Trust. To the extent additional capital expenditures are incurred to increase reserves, the Trust anticipates financing them through proceeds received on exercise of employee unit options, equity placements or from its line of credit.

Periods may exist where the cost of replacing reserves exceeds the level of funds withheld. However, the Trust, with its long life reserves and relatively low debt levels compared to other income trusts, has the flexibility to increase or decrease its capital commitments depending on commodity prices and costs of development.

It is management's strategy to finance the costs of reclamation as well as potential income taxes (commencing in 2011) resulting from the recently enacted income trust tax law from the adjusted distribution base. Management is reviewing various organizational alternatives and operational strategies to mitigate the impact of the new tax.

Compliance with Financial Covenants

Due to the relatively low debt levels maintained by the Trust, the Trust's loan agreements do not contain any debt covenants other than that the debt is payable upon demand.

Per Unit and Ratio Disclosures

($000 except $ per unit)	**Six Months Ended June 30, 2008**	Six Months Ended June 30, 2007	Cumulative Amounts From Inception of Trust (July 1, 2001) to June 30, 2008
Standardized Distributable Cash	**27,778**	16,854	151,555
Per weighted average unit	**1.64**	1.00	9.64
Per fully diluted unit	**1.63**	1.00	9.59
Cash distributions [(1)]	**26,211**	22,309	230,510
Payout ratio	**0.94**	1.32	1.52
Adjusted Distribution Base	**39,410**	24,824	269,303
Per weighted average unit	**2.32**	1.47	17.25
Per fully diluted unit	**2.31**	1.47	17.13
Cash distributions [(1)]	**26,211**	22,309	230,510
Payout ratio	**0.67**	0.90	0.86

[(1)] Includes distribution declared in July 2008 and 2007 in respect of June 2008 and 2007 operations, respectively.

On a go forward basis, the Trust plans to maintain the payout ratio in respect of Standardized Distributable Cash at a level between 110 to 120 percent to facilitate a debt to cash flow level of less than one year and to not incur current tax (excluding Saskatchewan Resource Surcharge). This will be attained through controlling costs of capital replacement, by examining lower cost methods of reserve replacement as well as increased cash flow from wells currently producing.

Tax Attributes of Distributions and the Trust's Assets

See discussion under Taxes.

Cash Netback

The following table illustrates the Trust's cash netback for the six month periods ended (the 2007 netback includes one time charges to royalties as described above in this report):

$ per Barrel of Oil Equivalent (BOE)	**June 30 2008**	June 30 2007
Production volumes (BOE)	**780,644**	757,485
Gross production revenue	**$90.02**	$59.73
Realized gain (loss) on risk management contracts	**(6.90)**	(1.08)
Royalties	**(12.38)**	(8.51)
Field operating costs	**(15.89)**	(15.80)
Field netback	**54.85**	36.50
General and administrative	**(2.22)**	(1.44)
Interest and taxes	**(2.18)**	(2.11)
Cash netback	**$50.45**	$32.95

The following table illustrates the Trust's cash netback for the three month periods:

$ per Barrel of Oil Equivalent (BOE)	**June 30 2008**	March 31 2008
Production volumes (BOE)	**385,468**	395,176
Gross production revenue	**$99.66**	$80.62
Realized gain (loss) on risk management contracts	**(10.43)**	(3.46)
Royalties	**(13.81)**	(10.99)
Field operating costs	**(15.80)**	(15.98)
Field netback	**59.62**	50.19
General and administrative	**(2.22)**	(2.22)
Interest and taxes	**(2.06)**	(2.30)
Cash netback	**$55.34**	$45.67

Related Party Transactions

The Trust holds 689,682 (December 31, 2007 – 689,682) common shares in Comaplex Minerals Corp. (Comaplex), a company with common directors and management with the Trust and its subsidiaries, which have a fair market value as of June 30, 2008 of $3,828,000 (December 31, 2007 - $4,014,000). Comaplex is a publically traded mineral company on the Toronto Stock Exchange. The Trust's ownership in Comaplex represents approximately 1.3 percent of the issued and outstanding common shares of Comaplex.

Comaplex paid a management fee to Bonterra Energy Corp. (Bonterra Corp.) (operating subsidiary of the Trust) of $165,000 (2007 - $150,000) during the six months ended June 30, 2008. Comaplex also shares office rental costs and reimburses Bonterra Corp. for costs related to employee benefits and office materials. In addition, Comaplex owns 204,633 (December 31, 2007 – 204,633) units in the Trust. Services provided by Bonterra Corp. include executive services (president and vice president, finance duties), accounting services, oil and gas administration and office administration. All services performed are charged at estimated fair value. At June 30, 2008, Comaplex owed the Trust $63,000 (December 31, 2007 - $63,000).

The Trust also has a management agreement with Pine Cliff Energy Ltd. (Pine Cliff). Pine Cliff has common directors and management with the Trust and its subsidiaries. Pine Cliff trades on the TSX Venture Exchange. Pine Cliff paid a management fee to Bonterra Corp. of $119,000 (2007 - $108,000) during the six months ended June 30, 2008. Services provided by Bonterra Corp. include executive services (president and vice president, finance duties), accounting services, oil and gas administration and office administration. All services performed are charged at estimated fair value. The Trust has no share ownership in Pine Cliff. As at June 30, 2008, the Trust had an account receivable from Pine Cliff of $1,000 (December 31, 2007 – $4,000).

Liquidity and Capital Resources

During the first six months of 2008, the Trust incurred capital costs of $8,964,000 (2007 - $9,324,000). The Trust and its partners drilled 13 gross (8.5 net) Cardium oil wells and one gross (0.1 net) shallow gas well in the first half of 2008.

The Trust currently has plans to drill a total of 30 gross (23 net) Cardium infill oil wells in 2008 and 5 gross shallow gas wells. Total capital costs of approximately $25,000,000 are budgeted for 2008. It is anticipated that the entire 2008 capital expenditures will be funded from cash flow and funds from the exercise of employee unit options. Should it be necessary, the Trust will use its financial facilities to cover any shortfall.

The Trust, through its operating subsidiaries, has a bank revolving credit facility of $69,900,000 at June 30, 2008 (December 31, 2007- $69,900,000). The credit facilities carry an interest rate of Canadian chartered bank prime.

The Trust is authorized to issue an unlimited number of trust units without nominal or par value. Equity transactions during the past three months are as follows:

Issued	Number	Amount
Trust Units		($000)
Balance, January 1, 2008	16,928,158	90,590
Issued pursuant to Trust's unit option plan	179,000	4,490
Transfer of contributed surplus to unit capital	–	449
Balance, June 30, 2008	17,107,158	95,528

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,710,700 (December 31, 2007 – 1,693,000) 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.

A summary of the status of the Trust's unit option plan as of June 30, 2008 and December 31, 2007, and changes during the six month and twelve month periods ending on those dates is presented below:

	June 30, 2008		December 31, 2007	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of period	1,177,000	$27.59	721,500	$26.55
Options granted	29,000	39.09	553,000	28.11
Options exercised	(179,000)	25.09	(53,500)	18.56
Options cancelled	–	–	(44,000)	27.92
Outstanding at end of period	1,027,000	$28.35	1,177,000	$27.59
Options exercisable at end of period	408,500	$27.48	530,000	$26.63

The following table summarizes information about unit options outstanding at June 30, 2008:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 6/30/08	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable At 6/30/08	Weighted-Average Exercise Price
$23.35	113,500	0.7 years	$23.35	113,500	$23.35
24.20-27.50	19,500	1.9 years	25.65	–	–
28.30-28.75	825,000	1.3 years	28.47	275,000	$28.75
32.00-33.75	40,000	1.4 years	33.55	20,000	$33.55
38.80-39.20	29,000	2.6 years	39.09	–	–
$23.35-$39.20	1,027,000	1.3 years	$28.35	408,500	$27.48

Disclosure Controls and Procedures

Disclosure controls and procedures have been designed to ensure the information required to be disclosed by the Trust is accumulated and communicated to the Trust's Management, as appropriate, to allow timely decisions regarding required disclosures. The Trust's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by the interim filings that the Trust's disclosure controls and procedures are effective to provide reasonable assurance that material information related to the issuer, is made known to them by others within the Trust. It should be noted that while the Trust's Chief Executive Officer and Chief Financial Officer believe that the Trust's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system is met.

Internal Control Update

Bonterra is required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings", otherwise referred to as Canadian SOX (C-Sox). The 2008 certificate requires that the Trust disclose in the interim MD&A any changes in the Trust's internal control over financial reporting that occurred during the period that has materially affected, or is reasonably likely to materially affect the Trust's internal control over financial reporting. The Trust confirms that no such changes were made to the internal controls over financial reporting during the first six months of 2008.

Financial Reporting Update

During 2008, the Trust adopted Section 1535 "Capital Disclosures," Section 3862, "Financial Instruments Disclosures" and Section 3863, "Financial Instruments - Presentation." All the above Sections were required to be adopted for fiscal years beginning on or after October 1, 2007. As a result, the Trust has added note 9 providing the required disclosures regarding the Trust's objectives, policies and processes for managing capital and the significance of financial instruments for the entity's financial position and performance; and the nature, extent and management of risks arising from financial instruments to which the entity is exposed.

Future Accounting Changes

In February 2008, the CICA issued Section 3064, "Goodwill and Intangible Assets," replacing Section 3062, "Goodwill and Other Intangible Assets" and Section 3450, "Research and Development Costs." Various changes have been made to other sections of the CICA Handbook for consistency purposes. The new section will be applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. Accordingly, the Trust will adopt the new standards for its fiscal year beginning January 1, 2009. This standard establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The Trust does not expect that the adoption of this new Section will have a material impact on its consolidated financial statements.

Additional information relating to the Trust may be found on SEDAR.COM.

For further information, please visit our website at www.bonterraenergy.com.

Submitted on behalf of the Board of Directors,

George F. Fink
President, CEO and Director

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 these 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.

The audit committee has reviewed these financial statements with management and has reported to the Board of Directors. The Board of Directors has approved the financial statements as presented in this interim report.

Consolidated Balance Sheets

As at June 30, 2008 (unaudited) and December 31, 2007

($000)	2008	2007
Assets		
Current		
Accounts receivable	**15,412**	10,575
Crude oil inventory	**648**	792
Parts inventory	**121**	132
Prepaid expenses	**2,388**	1,330
Future income tax asset (Note 5)	**2,986**	913
Investments in related party (Note 2)	**3,828**	4,014
	25,383	17,756
Property and Equipment (Note 3)		
Petroleum and natural gas properties and related equipment	**196,243**	187,288
Accumulated depletion and depreciation	**(68,379)**	(61,805)
Net Property and Equipment	**127,864**	125,483
	153,247	143,239
Liabilities		
Current		
Distributions payable	**5,474**	3,724
Accounts payable and accrued liabilities	**13,967**	12,291
Derivative liability	**10,110**	3,085
Debt (Note 4)	**52,980**	57,422
	82,531	76,522
Future Income Tax Liability (Note 5)	**10,741**	7,595
Asset Retirement Obligations	**13,363**	14,904
	106,635	99,021
Commitments (Note 9)		
Unitholders' Equity (Note 6)		
Unit capital	**95,528**	90,590
Contributed surplus	**2,254**	2,140
	97,782	92,730
Deficit	**(54,037)**	(51,543)
Accumulated other comprehensive income (Note 7)	**2,867**	3,031
	(51,170)	(48,512)
Total Unitholders' Equity	**46,612**	44,218
	153,247	143,239

Consolidated Statements of Unitholders' Equity

For the periods ended June 30 (unaudited)

($000)	Three Months 2008	Three Months 2007	Six Months 2008	Six Months 2007
Unitholders' equity, beginning of period	**48,136**	57,646	**44,218**	53,359
Comprehensive income for the period	**12,577**	5,017	**23,552**	13,661
Adjustment of opening accumulated comprehensive income	**–**	–	**–**	2,380
Net capital contributions	**4,210**	234	**4,490**	705
Unit based compensation adjustment	**279**	185	**562**	403
Distributions declared	**(18,590)**	(11,162)	**(26,210)**	(18,588)
Unitholders' Equity, End of Period	**46,612**	51,920	**46,612**	51,920

Consolidated Statements of Operations and Deficit

For the periods ended June 30 (unaudited)

($000, except $ per unit)	Three Months 2008	Three Months 2007 (Note 11)	Six Months 2008	Six Months 2007 (Note 11)
Revenue				
Oil and gas sales	**38,412**	23,237	**70,272**	45,249
Realized gain (loss) on risk management contracts	**(4,014)**	225	**(5,381)**	815
Unrealized gain (loss} on risk management contracts (Note 10)	**(4,636)**	1,313	**(7,025)**	(439)
Royalties	**(5,319)**	(3,868)	**(9,663)**	(6,446)
Interest and other	**9**	12	**22**	33
	24,452	20,919	**48,225**	39,212
Expenses				
Production costs	**6,089**	6,556	**12,406**	12,137
General and administrative	**855**	527	**1,732**	1,091
Interest on debt	**650**	744	**1,449**	1,441
Unit option based compensation	**279**	185	**562**	403
Dry hole costs	**–**	9	**–**	476
Depletion, depreciation and accretion	**3,516**	3,284	**7,010**	6,786
	11,389	11,305	**23,159**	22,334
Earnings Before Taxes	**13,063**	9,614	**25,066**	16,878
Taxes (Note 5)				
Current	**142**	84	**253**	158
Future	**9**	4,159	**1,097**	3,687
	151	4,243	**1,350**	3,845
Net Earnings for the Period	**12,912**	5,371	**23,716**	13,033
Deficit at beginning of period	**(48,359)**	(37,009)	**(51,543)**	(37,245)
Distributions declared	**(18,590)**	(11,162)	**(26,210)**	(18,588)
Deficit at End of Period	**(54,037)**	(42,800)	**(54,037)**	(42,800)
Net Earnings Per Trust Unit – Basic	**0.76**	0.32	**1.40**	0.77
Net Earnings Per Trust Unit – Diluted	**0.75**	0.32	**1.39**	0.77

Consolidated Statements of Comprehensive Income (Loss)

For the periods ended June 30 (unaudited)

($000, except $ per unit)	Three Months 2008	Three Months 2007 (Note 11)	Six Months 2008	Six Months 2007 (Note 11)
Net Earnings for the Period	**12,912**	5,371	**23,716**	13,033
Unrealized gains (losses) on investments (net of income taxes; three months ended 2008 - 25, 2007 - (61), six months ended 2008 - (22), 2007 - 109)	**(335)**	(354)	**(164)**	628
Other Comprehensive Income (Loss)	**(335)**	(354)	**(164)**	628
Comprehensive Income	**12,577**	5,017	**23,552**	13,661
Comprehensive Income Per Trust Unit – Basic	**0.74**	0.30	**1.39**	0.81
Comprehensive Income Per Trust Unit – Diluted	**0.73**	0.30	**1.38**	0.81

Consolidated Statements of Cash Flows

For the periods ended June 30 (unaudited)

($000)	Three Months 2008	Three Months 2007 (Note 11)	Six Months 2008	Six Months 2007 (Note 11)
Operating Activities				
Net earnings for the period	**12,912**	5,371	**23,716**	13,033
Items not affecting cash				
Unrealized loss on risk management contracts	**4,636**	(1,313)	**7,025**	439
Unit option based compensation	**279**	185	**562**	403
Dry hole costs	**–**	9	**–**	476
Depletion, depreciation and accretion	**3,516**	3,284	**7,010**	6,786
Future income taxes	**9**	4,159	**1,097**	3,687
	21,352	11,695	**39,410**	24,824
Change in non-cash working capital				
Accounts receivable	**(1,636)**	60	**(4,837)**	599
Crude oil inventory	**(55)**	79	**87**	65
Parts inventory	**(3)**	16	**11**	24
Prepaid expenses	**(1,113)**	(502)	**(1,058)**	(454)
Accounts payable and accrued liabilities	**2,171**	2,326	**5,042**	1,429
Asset retirement obligations settled	**(186)**	(261)	**(1,913)**	(309)
	(822)	(1,718)	**(2,668)**	1,354
Cash Provided by Operating Activities	**20,530**	13,413	**36,742**	26,178
Financing Activities				
Increase (decrease) in debt	**(5,933)**	1,766	**(4,442)**	9,222
Unit option proceeds	**4,210**	234	**4,490**	705
Unit distributions	**(13,116)**	(11,162)	**(24,460)**	(22,638)
Cash Used in Financing Activities	**(14,839)**	(9,162)	**(24,412)**	(12,711)
Investing Activities				
Property and equipment expenditures	**(2,543)**	(1,699)	**(8,964)**	(9,324)
Change in non-cash working capital				
Accounts receivable	**–**	729	**–**	993
Accounts payable and accrued liabilities	**(3,148)**	(3,281)	**(3,366)**	(5,136)
Cash Used in Investing Activities	**(5,691)**	(4,251)	**(12,330)**	(13,467)
Net Cash Inflow	**–**	–	**–**	–
Cash, beginning of period	**–**	–	**–**	–
Cash, End of Period	**–**	–	**–**	–
Cash Interest Paid	**650**	744	**1,449**	1,441
Cash Taxes Paid	**90**	93	**368**	183

1. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies and methods of application followed in the preparation of the interim financial statements other than described below are the same as those followed in the preparation of the Trust's 2007 annual financial statements. These interim financial statements do not include all disclosure requirements for annual financial statements. The interim financial statements as presented should be read in conjunction with the 2007 annual financial statements.

The Trust adopted Section 1535 "Capital Disclosures," Section 3862, "Financial Instruments – Disclosures" and Section 3863, "Financial Instruments – Presentation." All the above Sections were required to be adopted for fiscal years beginning on or after October 1, 2007. As a result, the Trust has added Note 9 providing the required disclosures regarding the Trust's objectives, policies and processes for managing capital and the significance of financial instruments for the entity's financial position and performance; and the nature, extent and management of risks arising from financial instruments to which the entity is exposed.

The Trust also adopted Section 3031 – "Inventories," which replaces Section 3030. This section is harmonized with International Accounting Standards and provides additional guidance on the measurement and disclosure requirements for inventories. This new standard did not have an impact on the Trust's financial statements.

Accounting changes

In February 2008, the CICA issued Section 3064, "Goodwill and Intangible Assets," replacing Section 3062, "Goodwill and Other Intangible Assets" and Section 3450, "Research and Development Costs." Various changes have been made to other sections of the CICA Handbook for consistency purposes. The new section will be applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. Accordingly, the Trust will adopt the new standards for its fiscal year beginning January 1, 2009. This standard establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The Trust does not expect that the adoption of this new Section will have a material impact on its consolidated financial statements.

2. INVESTMENT IN RELATED PARTY

The investment consists of 689,682 (December 31, 2007 – 689,682) common shares in Comaplex Minerals Corp. (Comaplex), a company with common directors and management. The investment is recorded at fair market value. The fair market value as determined by using the trading price of the stock at June 30, 2008 of $5.55 per share and at December 31, 2007 of $5.82 per share. The common shares trade on the Toronto Stock Exchange under the symbol CMF. The investment represents less than one and a half percent ownership in the outstanding shares of Comaplex.

3. PROPERTY AND EQUIPMENT

	June 30, 2008		December 31, 2007	
($000)	**Cost**	**Accumulated Depletion and Depreciation**	Cost	Accumulated Depletion and Depreciation
Undeveloped land	**316**	**–**	316	–
Petroleum and natural gas properties and related equipment	**194,872**	**67,624**	185,947	61,105
Furniture, equipment and other	**1,055**	**755**	1,025	700
	196,243	**68,379**	187,288	61,805

4. DEBT

The Trust, through its operating subsidiaries, has a bank revolving credit facility of $69,900,000 at June 30, 2008 (December 31, 2007 – $69,900,000). 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. Letters of credit totalling $355,000 (December 31, 2007 – $355,000) were issued at June 30, 2008. Security for the credit facility consists of various fixed and floating demand debentures totalling $79,000,000 over all of the Trust's assets, and a general security agreement with first ranking over all personal and real property.

The credit facility carries an interest rate of Canadian chartered bank prime. Cash interest paid during the six month periods ended June 30, 2008 and 2007 for these loans was $1,499,000 and $1,441,000, respectively.

5. TAXES

The Trust has recorded a future income tax liability and a current income tax asset related to assets and liabilities and related tax amounts:

($000)	**June 30, 2008**	December 31, 2007
Future income tax liability related to assets and liabilities:	**12,584**	11,517
Future tax asset related to finance costs:	**(46)**	(79)
Future tax asset related to corporate tax losses carried forward in the subsidiary companies	**(1,797)**	(3,843)
Future income tax liability	**10,741**	7,595
Future income tax asset related to current portion of derivative liability	**2,986**	913

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

($000)	Rate of Utilization %	Amount
Undepreciated capital costs	20-100	16,899
Canadian oil and gas property expenditures	10	1,620
Canadian development expenditures	30	30,651
Canadian exploration expenditures	100	93
Income tax losses carried forward [1]	100	7,084
		56,347

[1] Income tax losses carried forward expire in 2026 ($215,000) and 2027 ($6,869,000).

The Trust has the following tax pools, which may be used in reducing future taxable income allocated to its Unitholders:

($000)	Rate of Utilization %	Amount
Canadian oil and gas property expenditures	10	13,555
Finance costs	20	195
Eligible capital expenditures	7	336
		14,086

On October 31, 2006, the Canadian Federal Government announced a proposed Trust taxation pertaining to taxation of distributions paid by publicly traded income trusts and this was enacted by legislation in June, 2007. Previously, distributions paid to Unitholders, other than returns of capital, were claimed as a deduction by the Trust in arriving at taxable income whereby tax is eliminated at the Trust level and tax is paid on the distributions by the Unitholders. The June, 2007 legislation results in a two-tiered tax structure whereby distributions commencing in 2011 would first be subject to a 31.5 percent tax at the Trust level and then investors would be subject to tax on the distribution as if it were a taxable dividend paid by a taxable Canadian corporation. The tax rate was subsequently lowered to 29.5 percent in 2011 and 28 percent in 2012 and thereafter.

On February 26, 2008, the Minister of Finance announced that instead of basing the provincial component of the trust tax rate on a flat rate of 13 percent, the provincial component will instead be based on the general provincial corporate tax rate in each province in which the income trust has a permanent establishment. Under the proposal, the Trust would be considered to have a permanent establishment in Alberta, where the provincial tax rate in 2011 is expected to be 10 percent. This would result in an overall tax rate to the Trust of 26.5 percent in 2011 and 25 percent thereafter.

Prior to June 2007, the Trust estimated the future income tax on certain temporary differences between amounts recorded on its balance sheet for book and tax purposes at a nil effective tax rate. The entire balance of the future income tax liability reported related to assets and liabilities and related tax amounts held through the Trust's 100 percent held subsidiaries. Under the legislation, the Trust now estimates the effective tax rate on post 2010 reversals of these temporary differences at the above mentioned tax rates. Temporary differences at the Trust level reversing before 2011 will still give rise to nil future income taxes.

Based on its assets and liabilities as at June 30, 2008, the Trust has estimated the amount of its temporary differences which are estimated to reverse post 2010 will be $14,303,000 (December 31, 2007 –$14,496,000) resulting in an additional $4,022,000 future income tax liability. The taxable temporary differences relate principally to the excess of net book value of oil and gas properties over the remaining tax pools attributable thereto.

While the Trust believes it will be subject to additional tax under the new legislation, the estimated effective tax rate on temporary difference reversals after 2011 may change in future periods. As the legislation is new, future technical interpretations of the legislation could occur and could materially affect management's estimate of the future income tax liability.

The amount and timing of reversals of temporary differences will also depend on the Trust's future operating results, acquisitions and dispositions of assets and liabilities, and distribution policy. A significant change in any of the preceding assumptions could materially affect the Trust's estimate of the future income tax liability.

6. 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		($000)
Balance, January 1, 2008	16,928,158	90,590
Issued pursuant to Trust's unit option plan	179,000	4,490
Transfer of contributed surplus to unit capital	–	449
Balance, June 30, 2008	17,107,158	95,528

The number of trust units used to calculate diluted net earnings per unit for the periods ended June 30:

	Three Months		**Six Months**	
	2008	2007	**2008**	2007
Basic units outstanding	17,025,803	16,911,916	**16,982,068**	16,905,494
Diluted effect of unit options	185,533	50,735	**102,363**	32,600
Diluted units outstanding	17,211,336	16,962,651	**17,084,431**	16,938,094

The deficit balance is composed of the following items:

($000)	**June 30, 2008**	June 30, 2007
Accumulated earnings	**176,472**	135,439
Accumulated cash distributions	**(230,509)**	(178,239)
Deficit	**(54,037)**	(42,800)

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,710,700 (December 31, 2007 – 1,693,000) 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.

A summary of the status of the Trust's unit option plan as of June 30, 2008 and December 31, 2007, and changes during the six month and twelve month periods ended on those dates is presented as follows:

	June 30, 2008		December 31, 2007	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of period	1,177,000	$27.59	721,500	$26.55
Options granted	29,000	39.09	553,000	28.11
Options exercised	(179,000)	25.09	(53,500)	18.56
Options cancelled	–	–	(44,000)	27.92
Outstanding at end of period	1,027,000	$28.35	1,177,000	$27.59
Options exercisable at end of period	408,500	$27.48	530,000	$26.63

The following table summarizes information about unit options outstanding at June 30, 2008:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 6/30/08	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable At 6/30/08	Weighted-Average Exercise Price
$23.35	113,500	0.7 years	$23.35	113,500	$23.35
24.20-27.50	19,500	1.9 years	25.65	–	–
28.30-28.75	825,000	1.3 years	28.47	275,000	28.75
32.00-33.75	40,000	1.4 years	33.55	20,000	33.55
38.80-39.20	29,000	2.6 years	39.09	–	–
$23.35-$39.20	1,027,000	1.3 years	$28.35	408,500	$27.48

The Trust records compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants. The Trust granted 29,000 unit options with an estimated fair value of $115,000 ($3.95 per option) in 2008 and 553,000 unit options in 2007 with an estimated fair value of $1,494,000 ($2.70 per option) using the Black-Scholes option pricing model with the following key assumptions:

	2008	2007
Weighted-average risk free interest rate (%)	2.9	4.7
Expected life (years)	2.5	2.3
Weighted-average volatility (%)	29.2	27.2
Dividend yield 2007	based on the percentage of distributions paid to the Unitholders during the year	

7. ACCUMULATED OTHER COMPREHENSIVE INCOME

($000)	January 1, 2008	Other Comprehensive Income (Loss)	June 30, 2008
Unrealized gains (losses) on available-for-sale financial assets	3,031	(164)	2,867

($000)	January 1, 2007	Other Comprehensive Income	December 31, 2007
Unrealized gains on available-for-sale financial assets	1,566	1,465	3,031

8. RELATED PARTY TRANSACTIONS

The Trust received a management fee from Comaplex of $165,000 (2007 – $150,000) for management services and office administration. This fee has been included as a recovery in general and administrative expenses. As at June 30, 2008, the Trust had an account receivable from Comaplex of $63,000 (December 31, 2007 – $63,000).

The Trust received a management fee from Pine Cliff Energy Ltd. (Pine Cliff) of $119,000 (2007 – $108,000) for management services and office administration. This fee has been included as a recovery in general and administrative expenses. As at June 30, 2008, the Trust had an account receivable from Pine Cliff of $1,000 (December 31, 2007 - $4,000).

The above charges represent the agreed to exchange amount of the services rendered.

9. FINANCIAL AND CAPITAL RISK MANAGEMENT

Financial Risk Factors

The Trust undertakes transactions in a range of financial instruments including:

- Receivables
- Payables
- Common share investments
- Bank loans
- Derivatives

The Trust's activities result in exposure to a number of financial risks including market risk (commodity price risk, interest rate risk, foreign exchange risk, credit risk, and liquidity risk).

Bonterra's overall risk management program seeks to mitigate these risks and reduce the volatility on the Trust's financial performance. Financial risk management is carried out by senior management under the direction of the Directors of Bonterra Energy Corp. (a subsidiary of the Trust).

The Trust enters into various risk management contracts in accordance with board approval to manage Bonterra's exposure to commodity price fluctuations. Currently no risk management agreements are in place in respect of interest rate risk. The Trust does not speculatively trade in risk management contracts. The Trust's risk management contracts are entered into to manage the risks relating to commodity prices from its business activities.

Capital Risk Management

The Trust's objectives when managing capital are to safeguard the Trust's ability to continue as a going concern, so that it can continue to provide returns to its Unitholders and benefits for other stakeholders and to maintain an optimal capital structure to reduce the cost of capital. In order to maintain or adjust the capital structure, the Trust may adjust the amount of distributions, the percentage of return of capital or issue new units.

The Trust monitors capital on the basis of the ratio of debt to adjusted distribution base. This ratio is calculated using each quarter end net debt (total debt adjusted for working capital) and divided by the annualized current quarter adjusted distribution base. For these purposes, the Trust defines adjusted distribution base as funds provided by operations before changes in non-cash operating working capital items excluding gains or losses on sale of property and asset retirement obligations.

The Trust believes that maintaining debt at or less than one year's adjusted distribution base is an appropriate level to allow it to take advantage in the future of either acquisition opportunities or to provide flexibility to develop its infill oil, shallow gas and coalbed methane potential without requiring the issuance of trust units.

Bonterra has a long-term goal to retain between 20 to 25 percent of its adjusted distribution base to finance its capital expenditures.

The following section (a) of this note provides a summary of the Trust's underlying economic positions as represented by the carrying values, fair values and contractual face values of the Trust's financial assets and financial liabilities. The Trust's debt to adjusted distribution base is also provided.

The following section (b) addresses in more detail the key financial risk factors that arise from the Trust's activities including its policies for managing these risks.

The following section (c) provides details of the Trust's risk management contracts that are used for financial risk management.

a) **Financial assets, financial liabilities and debt ratio**

The carrying amounts, fair value and face values of the Trust's financial assets and liabilities are shown in Table 1.

Table 1

	As at June 30, 2008			As at December 31, 2007		
($000)	Carrying Value	Fair Value	Face Value	Carrying Value	Fair Value	Face Value
Financial assets						
Accounts receivable	15,412	15,412	15,441	10,575	10,575	10,595
Investments in related party	3,828	3,828	N/A	4,014	4,014	N/A
Financial liabilities						
Distribution payable	5,474	5,474	5,474	3,724	3,724	3,724
Accounts payable and accrued liabilities	13,967	13,967	13,967	12,291	12,291	12,291
Derivative liability	10,110	10,110	–	3,085	3,085	–
Debt	52,980	52,980	52,980	57,422	57,422	57,422

The net debt and adjusted distribution base figures for the three months ended June 30, 2008 and June 30, 2007 are presented in Table 2.

Table 2

For the three month periods ended ($000)	June 30, 2008	June 30, 2007
Debt	52,980	54,601
Distribution payable	5,474	–
Accounts payable and accrued liabilities	13,967	10,041
Derivative liability	10,110	–
Current assets	(25,383)	(15,047)
Net Debt	57,148	49,595
Cash flow from operations	20,530	13,413
Changes in non-cash operating working capital	636	(1,979)
Asset retirement obligations settled	186	261
Adjusted Distribution Base	21,352	11,695
Annualized adjusted distribution base	85,408	46,780
Net debt to adjusted distribution base	0.67	1.06

b) **Risks and mitigations**

Market risk is the risk that the fair value or future cash flow of the Trust's financial instruments will fluctuate because of changes in market prices. Components of market risk to which Bonterra is exposed are discussed below.

Commodity price risk

The Trust's principal operation is the production and sale of crude oil, natural gas and natural gas liquids. Fluctuations in prices of these commodities directly impact the Trust's performance and ability to continue with its distributions.

The Trust currently uses various risk management contracts to set price parameters for a portion of its production (see section c below). Management, in agreement with the Board of Directors, recently decided that at least in the near term it will discontinue the use of commodity price agreements. The Trust will assume full risk in respect of commodity prices.

Sensitivity Analysis

Commodity prices have fluctuated significantly over the recent past. The following table updates the cash flow sensitivity for movements in the commodity prices of $1 U.S. WTI for crude oil, $0.10 per MCF AECO for natural gas and $0.01 fluctuation in exchange rates. These figures have been updated from December 31, 2007 to include commodity price hedges entered into during the first half of 2008.

	Cash Flow
U.S. $1.00 per barrel	$ 692,000
Canadian $0.10 per MCF	$ 181,000
Change of Canadian $0.01/U.S. $ exchange rate	$ 587,000

Interest rate risk

Interest rate risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to changes in market interest rates. Interest rate risk arises from interest bearing financial assets and liabilities that Bonterra uses. The principal exposure of the Trust is on its bank borrowings which have a variable interest rate which gives rise to a cash flow interest rate risk.

Bonterra's debt consists of an operating line as well as borrowings by means of banker acceptances (BA's). The Trust manages its exposure to interest rate risk through entering into various term lengths on its BA's but in no circumstances do the terms exceed six months. As discussed above, the Trust manages its capital such that its debt to adjusted distribution base is no higher than one year. This allows flexibility in obtaining cost effective financing.

Sensitivity Analysis

Based on historic movements and volatilities in the interest rate markets and management's current assessment of the financial markets, the Trust believes that a one percent variation in the Canadian prime interest rate is reasonably possible over a 12-month period. No income tax effect has been calculated as the Trust remains non-taxable until January 1, 2011.

The following illustrates the annual impact of a one percent fluctuation in the Canadian prime rate:

	As at June 30, 2008			
	Plus 1%		Minus 1%	
($000)	Earnings	Equity	Earnings	Equity
Financial assets				
Accounts receivable	–	–	–	–
Investments in related party	–	–	–	–
Financial liabilities				
Distribution payable	–	–	–	–
Accounts payable and accrued liabilities	–	–	–	–
Derivative liability	–	–	–	–
Debt	(530)	(530)	530	530
Total increase (decrease)	(530)	(530)	530	530

	As at December 31, 2008			
	Plus 1%		Minus 1%	
($000)	Earnings	Equity	Earnings	Equity
Financial assets				
Accounts receivable	–	–	–	–
Investments	–	–	–	–
Financial liabilities				
Distribution payable	–	–	–	–
Accounts payable and accrued liabilities	–	–	–	–
Derivative liability	–	–	–	–
Debt	(574)	(574)	574	574
Total increase (decrease)	(574)	(574)	574	574

Foreign exchange risk

The Trust has no foreign operations and currently sells all its product sales in Canadian currency. The Trust however is exposed to currency risk in that crude oil is priced in US currency then converted to Canadian currency. Bonterra mitigates some of this risk by using risk management contracts for a portion of its crude oil production in Canadian dollars. Please refer to sensitivity analysis under commodity price risk as well as section c below for a list of currently outstanding risk management agreements. Management, in agreement with the Board of Directors, recently decided that at least in the near term it will discontinue the use of commodity price agreements. The Trust will assume full risk in respect of foreign exchange fluctuations.

Credit risk

Credit risk is the risk that a contracting party will not complete its obligations under a financial instrument and cause the Trust to incur a financial loss. Bonterra is exposed to credit risk on all financial assets included on the balance sheet. To help mitigate this risk:

- The Trust only enters into material agreements with credit worthy counterparties. These include major oil and gas companies or one of the major Canadian chartered banks.
- Agreements for product sales are primarily on 30 day renewal terms.
- Investments are only with companies that have common management with the Trust.

Of the accounts receivable balance of June 30, 2008 ($15,412,000) and December 31, 2007 ($10,575,000) over 90 percent relates to product sales with international oil and gas companies. All of the derivative contracts as of both June 30, 2008 and December 31, 2007 were with either Bonterra's principal banker or its major crude oil purchaser.

The Trust assesses quarterly, if there has been any impairment of the financial assets of the Trust. During the three month period ended June 30, 2008 there was no impairment provision required on any of the financial assets of the Trust due to historical success of collecting receivables. The Trust does have a credit risk exposure as the majority of the Trust's accounts receivable are with counterparties having similar characteristics. However, payments from the Trust's largest accounts receivable counter parties have always been received within 30 days and the sales agreements with these parties are cancellable with 30 days notice if payments are not received.

The carrying value of accounts receivable approximates their fair value due to the relatively short periods to maturity on this instrument. The maximum exposure to credit risk is represented by the carrying amount on the balance sheet. There are no material financial assets that the Trust considers past due.

Liquidity risk

Liquidity risk includes the risk that, as a result of Bonterra's operational liquidity requirements:

- The Trust will not have sufficient funds to settle a transaction on the due date,
- Bonterra will not have sufficient funds to continue with its distributions,
- The Trust will be forced to sell assets at a value which is less than what they are worth, or
- Bonterra may be unable to settle or recover a financial asset at all.

To help reduce these risks the Trust:

- Has a capital policy of maintaining no more than a one year debt to adjusted distribution base.
- Uses of derivative instruments that are readily tradable should the need arise.
- Maintains a portfolio of high-quality long reserve life oil and gas assets.

c) **Risk management contracts**

The Trust entered into the following commodity hedging contracts for a portion of its 2008 production:

Period of Agreement	Commodity	Volume per day	Index	Price (Cdn)
July 1, 2008 to December 31, 2008	Crude Oil	500 barrels	WTI	Floor of $73.00 and ceiling of $80.68 per barrel
July 1, 2008 to December 31, 2008	Crude Oil	500 barrels	WTI	Floor of $85.00 and ceiling of $104.80 per barrel
April 1, 2008 to October 31, 2008	Natural Gas	1,500 GJ's	AECO	Floor of $6.00 and ceiling of $7.60 per GJ

As of June 30, 2008, the fair value of the outstanding commodity risk management contracts was a net liability of $10,110,000 (December 31, 2007 – $3,085,000).

10. UNREALIZED LOSS ON RISK MANAGEMENT CONTRACTS

The following table reconciles the movement in the fair value of the Trust's financial risk management contracts that have not been designated as effect accounting hedges for the periods ended June 30:

	Three Months		**Six Months**	
($000)	2008	2007	**2008**	2007
Fair Value, beginning of period	(5,474)	(603)	**(3,085)**	1,149
Fair Value, end of period	(10,110)	710	**(10,110)**	710
Unrealized loss on risk management contracts	(4,636)	1,313	**(7,025)**	(439)

11. RESTATEMENT

The Trust has determined that its cash flow hedges on commodities are no longer effective hedges for accounting purposes. The following financial statement items have been restated to eliminate the use of hedge accounting:

Three months ended June 30, 2007

($000 except $ per unit)	Reported	Adjustment	Restated
Unrealized gain (loss) on risk management contracts	–	1,313	1,313
Future tax expense	3,777	382	4,159
Net earnings for the period	4,440	931	5,371
Deficit at beginning of period	(35,767)	(1,242)	(37,009)
Deficit at end of period	(42,489)	(311)	(42,800)
Net earnings per unit (basic and diluted)	0.26	(0.06)	0.32
Other comprehensive income	577	(931)	(354)

Six months ended June 30, 2007

($000 except $ per unit)	Reported	Adjustment	Restated
Unrealized loss on risk management contracts	–	(439)	(439)
Future tax expense	3,815	(128)	3,687
Net earnings for the period	13,344	(311)	13,033
Deficit at end of period	(42,489)	(311)	(42,800)
Net earnings per unit (basic and diluted)	0.79	(0.02)	0.77
Other comprehensive income	317	311	628

12. SUBSEQUENT EVENT – DISTRIBUTION

Subsequent to June 30, 2008, the Trust declared distributions of $0.32 per unit payable on August 31, 2008 to Unitholders of record on August 15, 2008.

Bonterra
Energy Income Trust

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