Bonterra
Energy Income Trust

Q3

2007 INTERIM REPORT

For the Period Ended September 30, 2007

Highlights

	Three Months Ended September 30		Nine Months Ended September 30	
	2007	2006	**2007**	2006
Financial ($000, except $ per unit)				
Revenue – oil and gas	**23,794**	23,665	**69,858**	67,015
Adjusted Distribution Base (1)	**13,149**	14,401	**37,973**	40,562
Per Unit - Basic	**0.78**	0.86	**2.25**	2.43
Per Unit - Diluted	**0.77**	0.85	**2.24**	2.40
Net Earnings	**9,086**	10,441	**22,430**	30,779
Per Unit - Basic	**0.54**	0.62	**1.33**	1.84
Per Unit - Diluted	**0.53**	0.62	**1.32**	1.82
Cash Distributions per Unit	**0.66**	0.72	**1.98**	2.10
Capital Expenditures and Acquisitions	**2,763**	12,597	**12,087**	28,891
Total Assets			**138,140**	130,655
Working Capital Deficiency (2)			**50,041**	38,853
Unitholders Equity			**50,820**	60,387
Operations				
Oil and NGL's				
Barrels Per Day	**3,054**	3,024	**3,118**	3,007
Average Price ($ per barrel)	**73.68**	71.11	**67.87**	66.06
Natural Gas				
MCF Per Day	**6,196**	5,925	**6,442**	6,059
Average Price ($ per MCF)	**5.47**	6.95	**6.77**	7.54
Total Barrels per Day	**4,088**	4,012	**4,192**	4,017

(1) Adjusted distribution base (formally funds flow from operations) is not a recognized measure under GAAP. Management believes that in addition to net earnings, adjusted distribution base is a useful supplemental measure as it demonstrates the Trust's ability to generate the cash 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") recently published recommendations regarding disclosure of a measure called Standardized Distributable Cash. Please refer to page 14 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following report dated November 8, 2007 is a review of the operations, current financial position and outlook for Bonterra Energy Income Trust ("Bonterra" or "the Trust") and should be read in conjunction with the unaudited financial statements for the nine months ended September 30, 2007, including the notes related thereto, and the audited financial statements for the fiscal year ended December 31, 2006, 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 therefrom. 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.

General

Bonterra is pleased to report its results for the first nine months of 2007. Oil and natural gas revenue increased by four percent from $67,015,000 in the 2006 nine month period to $69,858,000 for the 2007 nine month period. The increase is mainly attributable to an increase in crude oil pricing (offset partially by lower natural gas prices as well as an increase in production volumes of 4.4 percent to 4,192 barrels of oil equivalent (BOE's) from 4,017 BOE's for the comparable nine month period.

Adjusted distribution base (formally funds flow from operations) and net earnings decreased by 6 and 27 percent respectively in 2007 compared to the results from the first nine months of 2006. Both reductions were impacted by second quarter one time issues that related to prior periods. The second quarter one time issues that affected net earnings and adjusted distribution base consisted of an approximate $750,000 royalty adjustment for 2005 and, 2006 and extra operating costs and reworking costs to existing producing and non-producing wells that will assist in increased production volumes in future quarters.

Other cash items that had a negative impact on adjusted distribution base and net earnings were an approximate $2,297,000 increase in operating costs, an interest expense increase of $1,082,000 and the elimination of Alberta royalty tax credits resulting in a reduction of revenue of $484,000 and no gain on sale of property in 2007 compared to a 2006 gain of $532,000.

Production volumes in Q3 were a little lower than budgeted, mainly due to overall weather related low production in July, and production problems for most of the quarter in the Peck Lake area of Saskatchewan (which has been corrected in Q4). Also production from new wells that are higher volume producers at higher pressures are overloading existing gathering systems and in some areas it is reducing production from older low pressure wells. Bonterra is presently dealing with this issue by reducing production volumes from some of its new wells. On a long term basis Bonterra will attempt to improve upon the issue by renting space on other companies gathering systems or by increasing compression in its own system.

These negatives more than offset the increase in oil and gas revenues (including hedging adjustments) of $2,843,000. Net earnings were also affected by an increase in non-cash items of $1,552,000 of depletion, depreciation and accretion, dry hole costs of $1,720,000 and additional future income taxes of $2,345,000 resulting from the Federal Governments legislated change in how income trusts will be taxed.

The above items also had an impact on the payout ratio for the first nine months of 2007 resulting in a payout ratio of 88 percent compared to an objective of 80 percent. The elimination of one time charges as well as increasing commodity prices should assist in improving upon this ratio for the balance of 2007. Bonterra's production consists of approximately 75 percent crude oil (most of which is light sweet gravity crude) and therefore is benefiting from the current strong crude oil pricing.

At September 30, 2007, Bonterra had 4 gross (3.2 net) Cardium oil wells, 6 gross (4.5 net) natural gas wells, and 4 gross (3.5 net) coal-bed methane wells (CBM) drilled but not on production. The Trust anticipates completing and tying-in 3 gross (2.4 net) Cardium wells as well as 3 gross (1.7 net) shallow gas wells by the end of Q4 2007. The Trust is currently examining the recompletion of one (.8 net) Cardium well and intends to have it on production by spring 2008. The remaining natural gas wells and CBM wells will not be tied in until later in 2008.

While service costs continue to be high, Bonterra will continue to focus more on directing capital expenditures towards completions, tie-ins, reworking of existing wells, recompletions of gas zones to take advantage of new commingling regulations for gas wells, and refracing of existing Cardium oil wells rather than just drilling new wells. Exceedingly wet weather during the second and third quarters delayed the implementation of the above however, the Trust still anticipates capital expenditure for 2007 to be $20 million. The Trust commenced in late October with its fall drill program and anticipates the drilling of 8 gross (7.9 net) Cardium oil wells by the end of the year.

The Trust continues to have upside potential by continuing to drill and develop its large inventory of undrilled locations and potentially from additional recovery of oil in place by water flooding, CO_2 sequestration, and by reworking and refracing existing producing and suspended wells.

With regard to dealing with the federal taxation changes that were announced on October 31, 2006 and now have been legislated, Bonterra is evaluating the implications and various alternatives that are available to mitigate the impact of the additional taxes commencing in 2011. One of the difficult issues that has to be dealt with is that Bonterra has three types of unitholders that are affected differently; being Canadian resident unitholders that hold the units outside of tax shelters (approximately 60 percent), Canadian resident unitholders that hold units within tax shelters (approximately 18 percent) and foreign unitholders (approximately 22 percent). Generally what is beneficial for one type of unitholder may be detrimental to other types of unitholders.

The recent announcement by the Alberta provincial government regarding changes to the royalty tax structure is expected to have a nominal positive or negative effect to the Trust. The Trust current production mix is predominantly low producing oil and natural gas wells that will be least affected by the royalty adjustment. Additional oil royalties that will be payable as a result of the currently high oil prices should be offset by reductions in natural gas royalties due to the low production status of most of the Trust's natural gas production.

Quarterly Comparisons

	2007 3rd	2007 2nd	2007 1st
Financial ($000, except $ per unit)			
Revenue - oil and gas	**23,794**	23,462	22,602
Adjusted Distribution Base [(1)]	**13,149**	11,695	13,129
Per Unit Basic	**0.78**	0.69	0.78
Per Unit Fully Diluted	**0.77**	0.69	0.78
Net Earnings	**9,086**	4,440	8,904
Per Unit Basic	**0.54**	0.26	0.53
Per Unit Fully Diluted	**0.53**	0.26	0.53
Cash Distributions	**0.66**	0.66	0.66
Capital Expenditures and Acquisitions	**2,763**	1,699	7,625
Total Assets	**138,140**	139,432	140,926
Working Capital Deficiency	**50,041**	49,595	49,288
Unitholders' Equity	**50,820**	51,920	57,646
Operations			
Oil and Liquids (barrels per day)	**3,054**	3,074	3,227
Natural Gas (MCF per day)	**6,196**	6,663	6,470

	2006 4th	2006 3rd	2006 2nd	2006 1st	2005 4th
Financial ($000, except $ per unit)					
Revenue - oil and gas	21,179	23,665	23,219	20,131	21,753
Adjusted Distribution Base [(1)]	12,235	14,401	14,008	12,153	12,489
Per Unit Basic	0.72	0.86	0.84	0.73	0.76
Per Unit Fully Diluted	0.72	0.85	0.83	0.72	0.76
Net Earnings	6,471	10,441	10,617	9,721	9,918
Per Unit Basic	0.39	0.62	0.64	0.58	0.59
Per Unit Fully Diluted	0.38	0.62	0.63	0.58	0.59
Cash Distributions	0.72	0.72	0.69	0.69	0.68
Capital Expenditures and Acquisitions	9,457	12,597	6,246	10,048	10,760
Total Assets	134,942	130,655	122,166	118,439	110,149
Working Capital Deficiency	50,187	38,853	28,820	25,532	21,972
Unitholders' Equity	53,359	60,387	61,202	61,365	57,322
Operations					
Oil and Liquids (barrels per day)	3,138	3,024	3,001	2,996	2,814
Natural Gas (MCF per day)	5,885	5,925	6,181	6,071	5,795

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Production

Average daily production volume for the nine months ended September 30, 2007 was 4,192 barrels of oil equivalent (BOE's) per day. 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 consists of 3,118 barrels per day of crude oil and natural gas liquids and 6,442 MCF per day of natural gas. Bonterra's first nine months 2006 average production was 4,017 BOE's per day consisting of 3,007 barrels per day of crude oil and natural gas liquids and 6,059 MCF per day of natural gas.

The Trust drilled 7 gross (6.4 net) Cardium oil wells and 2 gross (0.7 net) shallow gas wells in the first nine months of 2007 on its operated lands. As at September 30, 2007 Bonterra had 4 gross (3.2 net) Cardium oil wells, 6 gross (4.5 net) natural gas wells and 4 gross (3.5 net) coal-bed methane ("CBM") wells drilled but not on production on its operated lands. During the first nine months of 2007, the Trust tied-in 15 gross (13 net) Cardium wells and 5 gross (2.8 net) natural gas wells on its operated lands.

As of the date of this report a further 100 percent owned Cardium well has been placed on production and management anticipates that 2 (1.4 net) of the remaining drilled but not producing Cardium wells will be completed and tied-in by the end of the fourth quarter of 2007. Three gross (1.7 net) of the natural gas wells are anticipated to be completed and tied-in by the end of the fourth quarter of 2007. The remaining shallow gas wells and CBM wells will not be completed and tied-in in 2007 for various reasons, including landowner issues, regulatory factors, gathering system capacity and line pressure issues.

The reduction in natural gas volumes is primarily due to operational problems at the Trusts Peck Lake property. Production from this area was down 225 MCF per day during the quarter. The production problem at Peck Lake has been rectified with production returning to approximately 80 percent of the field's first quarter levels in late October. Overall production rates in the third quarter of 2007 were affected by unseasonably wet summer weather resulting in the inability to perform maintenance on wells as well as higher initial declines in production on the newly completed Cardium oil wells which is a normal happening for new Cardium wells.

On October 30, 2007, the Trust completed an asset exchange agreement whereby it disposed of its entire interest in the Dodsland area of Saskatchewan properties in exchange for 100 percent interests in approximately 30 producing wells and an additional interest in an operated property all located in the Pembina area of Alberta. The exchange will have no impact on total production as the Dodsland properties were producing approximately 265 BOE per day and the acquired properties are expected to produce approximately 270 BOE per day. However, the newly acquired properties are expected to produce approximately 185 barrels per day of crude oil and natural gas liquids and approximately 500 MCF per day of natural gas whereas the Dodsland properties produced 245 barrels per day of crude oil and natural gas liquids and only 110 MCF per day of natural gas.

The exchange allows the Trust to increase its presence in the Pembina area of Alberta allowing for further consolidation of its operations including the tieing in of two (1.4 net) Cardium wells (see above). It should also result in a significant reduction in the Trust's operating costs as the acquired properties are anticipated to have operating costs in the $18 per BOE range verses $37 plus per BOE for the Dodsland assets. The exchange also reduces the number of wells owned by the Trust as the Dodsland property contained in excess of 400 wells whereas the Pembina properties acquired have approximately 40 total wells. The exchange will also result in a slightly higher average royalty rate as the newly acquired properties have a royalty rate of approximately 12 percent compared to 2.5 percent for the Dodsland properties. Overall it is expected that this property exchange will be neutral from a cash flow perspective.

Revenue

Revenue from petroleum and natural gas sales was $69,858,000 (2006 - $67,015,000). The increase in revenue over the 2006 first nine months was primarily due to additional production from the wells drilled during 2006 and spring of 2007. The average price received for crude oil and natural gas liquids during the first nine months of 2007 was $67.87 ($73.68 in the third quarter) per barrel and $6.77 ($5.47 in the third quarter) per MCF for natural gas compared to $66.06 per barrel and $7.54 per MCF in the corresponding 2006 period. On a quarter over quarter basis, revenue increased by $332,000 due primarily to increased crude oil prices from second quarter pricing of $67.60 offset partially by reduced production volumes.

Gross revenue has been increased by $924,000 (2006 decreased by $695,000) due to higher prices received as a result of price hedging. The Trust will continue to assess hedging future production to assist in managing its cash flow. The Trust continues to follow the policy of protecting production that has high operating costs with hedges that provide a significant level of profitability and also to provide for a reasonable amount of funds flow protection for development projects. The Trust will however maintain a policy of not hedging more than 50 percent of production to allow it to benefit from any price movements in either crude oil or natural gas. Kindly refer to Note 9 to the attached interim financial statements for present hedging details. At September 30, 2007, the fair value of the outstanding commodity hedging contracts was a net asset of $511,000 (December 31, 2006 - $1,148.000).

Royalties

During the second quarter of 2007, two significant royalty adjustments were recorded.

Firstly, the Trust discovered that the production limit, resulting in additional gross overriding royalty in respect of certain of its Cardium oil wells, had been reached. The production limit was calculated on a multitude of Cardium wells including several that were not owned by the Trust. In addition the exact wells that the production limit was applicable to was not readily known by the Trust nor easily determined. In discussions with the payee it was determined that the production limit was reached in late 2005. The royalty has been calculated based on this agreed date and the affected wells for Bonterra and other operators in the area were identified. The approximate amount of the adjustment, net to the Trust is $700,000 for periods prior to April 1, 2007. The monthly amount of the royalty on a go forward basis is approximately $40,000 per month based on current pricing and production levels.

Secondly, the Trust was informed by the operator of one of its non-operated properties that it had not charged a net profit royalty for the years 2004, 2005 and 2006. In review of the agreements it was confirmed no payment was made and an amount of approximately $150,000 was accrued by the Trust for payment of such net profit royalty.

Royalties paid by the Trust consist of Crown royalties paid to the Provinces of Alberta and Saskatchewan as well as numerous gross override and freehold royalties. During the first nine months of 2007 the Trust paid $6,575,000 (2006 - $6,546,000) in Crown royalties and $2,553,000, which includes the above described adjustments of $700,000 and $150,000, (2006 - $1,552,000) in freehold royalties, gross overriding royalties and net carried interests. The majority of the Trust's wells are low productivity wells and therefore have low Crown royalty rates. The Trust's average Crown royalty rate is approximately 9.5 percent (2006 – ten percent) and approximately 2.5 percent (after adjusting for the one time items discussed above) (2006 – 2 percent) for other royalties before hedging adjustments. The previously discussed property swap will result in a one to two percent increase in the average royalty rate on a go forward basis. The Trust was eligible for Alberta Crown Royalty rebates for Alberta production from all wells that it drilled on Crown lands and from a small amount of purchased wells; however this program was discontinued by the Alberta Government effective January 1, 2007 which resulted in a reduction of revenue of $484,000 in 2007.

Gain on Sale of Property

During the first quarter of 2006, the Trust disposed of a non-operated; non-core property for gross proceeds of $750,000 (approximately $75,000 per producing BOE). The Trust follows successful efforts accounting for its oil and gas properties and therefore reported a gain of $532,000 on the difference between the depleted value of the property and the above proceeds.

Production Costs

Production costs for the nine months ended September 30, 2007 were $18,538,000 compared to $16,241,000 for the nine months ended September 30, 2006. On a BOE basis production costs averaged $16.20 in 2007 ($17.02 in Q3) verses $14.81 in the corresponding 2006 period. Production costs in Q3 decreased $155,000 from Q2 due to the Trust performing numerous maintenance programs on its oil producing facilities and pipelines and the operator of a number of the Trusts gas plants performing its annual turnarounds during the second quarter. Costs also have continued to increase for services related to well workovers.

The Trust is facing continuing maintenance issues with regard to its infrastructure to accommodate the additional production resulting from its 2006 and 2007 drill programs resulting in significant additional operational costs. However, the swap of the Dodsland properties for additional Pembina properties should result in a reduction of total operating costs on a go forward basis.

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 lease, power and personnel costs are not variable with production volumes. Production costs in the $14 to $15 per BOE range are expected. The high production costs for the Trust are substantially offset by low royalty rates of approximately 12.5 percent, which is much lower than industry average for conventional production and results in high cash net backs on a combined basis despite higher than average production costs.

General and Administrative Expenses

General and administrative expenses were $1,864,000 ($773,000 in the third quarter) in the first nine months of 2007 compared to $1,814,000 in the nine months ended September 30, 2006 and $527,000 in the three months ended June 30, 2007. Costs on a BOE bases decreased to $1.63 per BOE in the first nine months of 2007 compared to $1.65 per BOE in the first nine months of 2006. On a quarter over quarter basis, administrative expenses increased by $246,000.

During the third quarter the Trust incurred approximately $275,000 in professional fees relating to the evaluation of several organizational options. This review was part of the Trusts continuing examination of means to address the changes resulting from the federal government's taxation of Trust's announcement on October 31, 2006. Off-setting these expenditures were increased recoveries (approximately $240,000) of administration expenses charged to the Trust's various partners and capital projects. Increases in employee salary compensation were offset by reduced bonus accruals and a general reduction in overall office expenditures.

Interest Expense

Interest expense increased to $2,150,000 ($709,000 in the third quarter) for the nine months ended September 30, 2007 compared to $1,068,000 for the nine months ended September 30, 2006. Increased average debt levels and increased interest rates were the primary factors in the increase in interest expense. The Trust's average borrowing rate for 2007 is approximately 5.6 percent compared to 5.5 percent for the first nine months of 2006. Quarter over quarter saw a decrease of $35,000. Although ending Q3 debt level was higher than Q2, the average outstanding debt balance was less. The Trust's net debt as a percentage of annualized third quarter adjusted distribution base was approximately eleven and a half months which is slightly below the Trust's goal of one year.

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.

In 2007, the Trust issued 546,000 unit options of which 517,000 were issued at the end of June 2007 at an average price of $28.31 and a fair value of $2.75 per unit. The fair value of the options granted has been estimated using the Black-Scholes option pricing model, assuming a weighted risk free interest rate of 4.7 (2006 – 4.1) percent, expected weighted average volatility of 27 percent (2006 – 27), expected weighted average life of 2.5 years (2006 – 2.5) and an annual dividend rate based on the distributions paid to the Unitholders during the year. As the options were issued at the end of the second quarter no significant expense in relation to these options was recorded in Q2. The future unit based compensation impact of these options is approximately $235,000 per quarter over the next four quarters.

Depletion, Depreciation and 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. Tangible assets are depreciated over an expected 10 year life. 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 $10,278,000 and $8,726,000 for the nine month periods ending September 30, 2007 and September 30, 2006 respectively. The increase was primarily due to increased production resulting from the Trust's 2006 and spring 2007 drill programs. The Trust continues to replace production declines with newly drilled wells that have higher capital costs. The Trust has capital costs of approximately $6 per proven BOE of reserves based on the December 31, 2006 independent engineering report. The increase in Q3 of $208,000 from Q2 depletion amounts was due to increased production volumes from newly completed wells resulting in higher depletion claims per BOE of production.

During the third quarter, the Trust reviewed its inventory of previously drilled natural gas and CBM wells. Various tests were performed and based on these results and continuing low natural gas prices it was determined that six gross (4.7 net) natural gas and CBM wells did not have sufficient economics to justify reserves and the capital costs for these wells totalling $1,244,000 were expensed as dry hole costs.

Income 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 and this was enacted by legislation in June 2007. Previously, distributions paid to unitholders, other than returns 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 at the Trust level tax and then investors would be subject to tax on the distribution as if it were a taxable dividend paid by a taxable Canadian corporation.

Future income tax expense for 2007 increased by a one time adjustment of $3,801,000, with a corresponding increase to the future tax liability, upon the June 2007 enactment. 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.

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 effect even though it is anticipated that many trusts will change their organizational structure to attempt to reduce this impact.

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 resource surcharge payable by the Trusts 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 current resource surcharge rate of 3.3 percent 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:

	Rate of Utilization %	Amount
Undepreciated capital costs	20-100	$16,324,000
Canadian oil and gas property expenditures	10	1,665,000
Canadian development expenditures	30	29,526,000
Canadian exploration expenditures	100	93,000
Income tax losses carried forward [(1)]	100	16,367,000
		$63,975,000

[(1)] Income tax losses carried forward expire in 2014 ($635,000), 2015 ($3,574,000), 2026 ($4,826,000) and 2027 ($7,332,000).

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

	Rate of Utilization %	Amount
Canadian oil and gas property expenditures	10	$14,583,000
Finance costs	20	411,000
Eligible capital expenditures	7	354,000
		$15,348,000

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

Net earnings decreased to $22,430,000 in the first nine months of 2007 from $30,779,000 in the corresponding 2006 period. Revenue increases due to increased production volumes were generally offset by increased operating costs, interest expense, depletion, depreciation accretion and dry hole costs, and provision for future income taxes. The Trust's quarter over quarter net earnings increased by $4,646,000 primarily due to future income tax adjustments.

Comprehensive Income

On January 1, 2007 the Trust became obliged to adopt the new accounting standards regarding the accounting for financial instruments. On adoption the Trust increased its investment in related party by $1,836,000 for the fair value of this investment. On January 1, 2007 the Trust further recognized a current asset of $1,148,000 for the fair value of its commodity derivative contracts. These adjustments resulted in a further increase in the future income tax liability and accumulated other comprehensive income of $604,000 and $2,380,000 respectively.

Other comprehensive income for the nine months included an increase in the unrealized gain on investment in a related party of $1,170,000 ($542,000 in the third quarter), a reduction of $654,000 ($77,000 in the third quarter) relating to the recognition and transfer of previously reported hedging gains in accumulated other comprehensive income and a gain of $202,000 was recorded in relation to the fair value adjustment on outstanding commodity derivative contracts. All of the above adjustments are net of applicable income tax effects.

Standardized Distributable Cash

Compliance with Guidance

The following Management, 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

	Nine Months Ended September 2007	Nine Months Ended September 2006	Cumulative Amounts From Inception of Trust (July 1, 2001)
Cash Flow from Operating Activities	**$38,064,000**	$40,019,000	$166,842,000
Less adjustment for:			
Capital expenditures	**(12,087,000)**	(28,891,000)	(75,198,000)
Financing restrictions caused by debt	**–**	–	–
Standardized Distributable Cash	**$25,977,000**	$ 11,128,000	$91,644,000

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

	Nine Months Ended September 2007	Nine Months Ended September 2006	Cumulative Amounts From Inception of Trust (July 1, 2001)
Standardized Distributable Cash – per above	**$25,977,000**	$ 11,128,000	$91,644,000
Adjusted for:			
Capital expenditures	**12,087,000**	28,891,000	75,198,000
Gain on sale of property	**–**	532,000	1,089,000
Changes in accounts receivable	**(369,000)**	(955,000)	4,494,000
Changes in crude oil inventory	**(33,000)**	186,000	304,000
Changes in parts inventory	**41,000**	(112,000)	(208,000)
Changes in prepaid expenses	**188,000**	604,000	254,000
Changes in accounts payable and accrued liabilities	**(450,000)**	(105,000)	1,594,000
Asset retirement obligations settled	**532,000**	393,000	1,709,000
Adjusted Distribution Base (formerly Funds Flow from Operations)[1]	**$37,973,000**	$40,562,000	$176,078,000

[1] Adjusted distribution base (formerly funds flow from operations) is not a recognized measure under GAAP. The Trust believes that in addition to net earnings, adjusted distribution base is a useful supplemental measure as it demonstrates the Trust's ability to generate the cash 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 seasonality impact in working capital.

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

	Nine Months Ended September 2007	Year ended December 31, 2006	Year ended December 31, 2005	Year ended December 31, 2004
Standardized Distributable Cash	**$25,977,000**	$13,596,000	$22,316,000	$18,875,000
Distributions [1]	**($33,474,000)**	($47,281,000)	($38,949,000)	($27,088,000)
Increase in bank debt	**$ 11,215,000**	$25,202,000	$11,717,000	($17,969,000)
Proceeds on exercise of employee unit options	**$845,000**	$5,161,000	$2,823,000	$3,292,000
Issuance of units (net of costs of issue)	**–**	–	($259,000)	$20,272,000
Proceeds on sale of properties	**–**	$750,000	$1,097,000	–
Non cash financing and investing working capital adjustments	**($4,563,000)**	$2,572,000	$1,255,000	$2,618,000

[1] Includes distribution declared in October in respect of September 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
2007 (including expenditures incurred to date)	$695,000
2008	494.000
2009	398,000
2010	986,000
2011	805,000
	$3,378,000

Definition and History of Productive Capacity and Strategy

Bonterra's primary objective is to grow its reserves from which it expects to generate cash flow so it will be able to continue with distributions for its unitholders. The Trust defines Productive Capacity Maintenance as the maintaining of the Trusts 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.

	Nine Months Ended September 2007	Year ended December 31, 2006	Year ended December 31, 2005	Year ended December 31, 2004
Proven and probable reserves at beginning of period (BOE's)	**26,476,000**	23,870,000	19,711,000	16,529,000
Reserves added due to acquisitions (BOE's)	**161,000**	16,000	2,393,000	–
Reserves added due to capital expenditures (BOE's)	[1]	4,082,000	3,100,000	4,351,000
Production during period (BOE's)	**1,144,000**	1,476,000	1,334,000	1,169,000
Increase in productive capacity (BOE's)	[1]	2,606,000	4,159,000	3,182,000
Reserves per unit (fully diluted)	**1.50**[2]	1.57	1.46	1.39
Productive capacity maintenance requirements	**$18,200,000**	$17,472,000	$9,205,000	$3,460,000
Capital expenditures for the period	**$12,087,000**	$38,348,000	$56,703,000	$10,595,000
Capital expenditures in excess of maintenance requirements	**($6,113,000)**	$20,876,000	$47,498,000	$7,135,000
Cost of increased productive capacity (per BOE)	[1]	$8.01	$11.42	$2.24

[1] The Trust does not update reserve information quarterly.

[2] Assuming no additional reserves in 2007.

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 15 to 20 percent of its adjusted distribution base to finance its capital maintenance expenditures. Over the past years, this level of retention of adjusted distribution base 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 exceed 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 the debt is payable upon demand.

Per Unit and Ratio Disclosures

	Nine Months Ended September 2007	Nine Months Ended September 2006	Cumulative Amounts From Inception of Trust (July 1, 2001)
Standardized Distributable Cash	**$25,977,000**	$ 11,128,000	$91,644,000
Per weighted average unit	**$1.54**	$0.67	$6.11
Per fully diluted unit	**$1.53**	$0.66	$6.06
Cash distributions [1]	**$33,474,000**	$35,132,000	$159,651,000
Payout ratio	**1.29**	3.16	1.74
Adjusted Distribution Base	**$37,973,000**	$40,562,000	$176,078,000
Per weighted average unit	**$2.25**	$2.43	$11.75
Per fully diluted unit	**$2.24**	$2.40	$11.64
Cash distributions [1]	**$33,474,000**	$35,132,000	$159,651,000
Payout ratio	**0.88**	0.87	0.91

[1] Includes distribution declared in October 2007 and 2006 in respect of September 2007 and 2006 operations respectively.

On a go forward basis the Trust plans to reduce the payout ratio in respect of Standardized Distributable Cash to a level between 110 to 120 percent to facilitate a debt to cash flow level of approximately one year and to incur no current income tax (excluding Saskatchewan Resource Surcharge). This will be attained through better 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 Income Taxes.

Cash Netback

The following table illustrates the Trust's cash netback per BOE for the nine month periods ended (The 2007 netback includes one time charges to royalties and field operating costs as described above in this report):

$ per Barrel of Oil Equivalent (BOE)	**September 30 2007**	September 30 2006
Production volumes (BOE)	**1,144,307**	1,096,723
Gross production revenue	**$61.05**	$61.11
Royalties	**(7.98)**	(6.94)
Field operating	**(16.20)**	(14.81)
Field netback	**36.87**	39.36
General and administrative	**(1.63)**	(1.65)
Interest and taxes	**(2.09)**	(1.24)
Cash netback	**$33.15**	$36.47

The following table illustrates the Trust's cash netback per BOE for the three month periods ended (The June 30 netback includes one time charges to royalties and field operating costs as described above in this report):

$ per Barrel of Oil Equivalent (BOE)	**September 30 2007**	June 30 2007
Production volumes (BOE)	**375,962**	380,891
Gross production revenue	**$63.29**	$61.61
Royalties	**(7.13)**	(10.16)
Field operating	**(17.02)**	(17.21)
Field netback	**39.14**	34.24
General and administrative	**(2.06)**	(1.38)
Interest and taxes	**(2.12)**	(2.17)
Cash netback	**$34.96**	$30.69

Related Party Transactions

The Trust received a management fee from Comaplex Minerals Corp., a company with common directors and management, of $225,000 (2006 - $225,000) for management services and office administration. In addition the Trust received a management fee from Pine Cliff Energy Ltd., a company with common directors and management, of $162,000 (2006 - $162,000) for management services and office administration. These recoveries have been offset against the Trust's general and administrative expense.

Liquidity and Capital Resources

During the first nine months of 2007, the Trust incurred capital costs of $12,087,000. The Trust drilled 7 gross (6.4 net) Cardium oil wells and 2 gross (0.7 net) shallow gas wells in the first nine months of 2007 on its operated lands.

The Trust currently has plans to drill a total of 17 gross (15 net) wells in 2007. Total capital cost of approximately $20,000,000 is budgeted for 2007. The capital expenditures will be funded from the adjusted distribution base, the Trusts lines of credit and funds from the exercising of employee unit options.

The Trust through its operating subsidiaries has a bank revolving credit facility of $69,900,000 at September 30, 2007 (December 31, 2006 - $49,900,000). 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 nine months are as follows:

Issued	Number	Amount
Trust Units		
Balance, January 1, 2007	16,874,658	$89,488,000
Issued pursuant to Trust's unit option plan	47,000	845,000
Transfer of contributed surplus to unit capital	–	93,000
Balance, September 30, 2007	16,921,658	$90,426,000

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,691,000 (December 31, 2006 – 1,687,000) 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 September 30, 2007 and December 31, 2006, and changes during the nine month and twelve month periods ending on those dates is presented below:

	September 30, 2007		December 31, 2006	
	Options	**Weighted-Average Exercise Price**	Options	Weighted-Average Exercise Price
Outstanding at beginning of period	**721,500**	**$26.55**	646,000	$18.67
Options granted	**546,000**	**28.12**	447,000	29.18
Options exercised	**(47,000)**	**17.97**	(339,500)	15.20
Options cancelled	**(44,000)**	**27.92**	(32,000)	24.70
Outstanding at end of period	**1,176,500**	**$27.57**	721,500	$26.55
Options exercisable at end of period	**229,500**	**$24.56**	212,500	$22.62

The following table summarizes information about unit options outstanding at September 30, 2007:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 9/30/07	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable At 9/30/07	Weighted-Average Exercise Price
$22.45-$23.35	231,500	1.5 years	$23.32	194,500	$23.31
$24.20-$25.00	20,000	2.3 years	24.21	–	–
$26.60	5,000	2.3 years	26.60	–	–
$28.30-$28.75	880,000	2.2 years	28.49	15,000	28.72
$32.00-$33.75	40,000	2.2 years	33.55	20,000	33.55
$22.45-$33.75	1,176,500	2.1 years	$27.57	229,500	$24.56

Disclosure Controls and Procedures Update

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 2007 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 nine months of 2007.

Financial Reporting Update

During 2007, the Trust completed the implementation of the new CICA Handbook Section 3855, Financial Instruments – Recognition and Measurement, Section 1530, Comprehensive Income and Section 3865, Hedges that deal with the recognition and measurement of financial instruments at fair value and comprehensive income. See notes 1 and 7 in the Notes to the Unaudited Interim Consolidated Financial Statements for further details.

Accounting Changes

Section 1506 permits voluntary changes in accounting policy only if they result in financial statements that provide more reliable and relevant information. Changes in policy are applied retrospectively unless it is impractical to determine the period or cumulative impact of the change. Corrections of prior period errors are applied retrospectively and changes in accounting estimates are applied prospectively by including these changes in net income. In addition, disclosure is required for all future accounting changes when an entity has not applied a new source of GAAP that has been issued but is not yet effective.

Future Accounting Changes

On December 1, 2006, the CICA issued three new accounting standards: Handbook Section 1535, Capital Disclosures, Section 3862, Financial Instruments – Disclosure, and Section 3863, Financial Instruments – Presentation. These new standards will be effective January 1, 2008.

Section 1535 specifies the disclosure of an entity's objectives, policies and processes for managing capital, quantitative data about what the entity regards as capital, whether the entity has complied with any capital requirements, and if it has not complied, the consequences of such non-compliance. This Section is expected to have minimal impact on the Trust's financial statements.

Sections 3862 and 3863 specify a revised and enhanced disclosure on financial instruments. Increased disclosure will be required on the nature and extent of risks arising from financial instruments and how the entity manages those risks.

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 Trust's auditors have not performed a review of these interim financial statements. 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 September 30, 2007 (unaudited) and December 31, 2006	**2007**	2006
Assets		
Current		
Accounts receivable	**$ 9,124,000**	$ 10,486,000
Crude oil inventory	**790,000**	843,000
Parts inventory	**155,000**	114,000
Prepaid expenses	**1,274,000**	1,086,000
Derivative asset (Note 1)	**511,000**	–
Investments in related party (Notes 1 and 2)	**3,669,000**	461,000
	15,523,000	12,990,000
Property and Equipment (Note 3)		
Petroleum and natural gas properties and related equipment	**186,526,000**	176,602,000
Accumulated depletion and depreciation	**(63,909,000)**	(54,650,000)
	122,617,000	121,952,000
	$ 138,140,000	$ 134,942,000
Liabilities		
Current		
Distribution payable	**$ –**	$ 4,050,000
Accounts payable and accrued liabilities	**8,970,000**	13,748,000
Debt (Note 4)	**56,594,000**	45,379,000
	65,564,000	63,177,000
Future Income Tax Liability (Note 5)	**6,914,000**	3,587,000
Asset Retirement Obligations	**14,842,000**	14,819,000
	87,320,000	81,583,000
Commitments (Note 9)		
Unitholders' Equity (Note 6)		
Unit capital	**90,426,000**	89,488,000
Contributed surplus	**1,863,000**	1,116,000
	92,289,000	90,604,000
Deficit	**(44,567,000)**	(37,245,000)
Accumulated other comprehensive income (Note 7)	**3,098,000**	–
	(41,469,000)	(37,245,000)
	50,820,000	53,359,000
	$ 138,140,000	$ 134,942,000

Consolidated Statements of Operations and Deficit

For the periods ended September 30 (unaudited)	Three Months		Nine Months	
	2007	2006	**2007**	2006
Revenue				
Oil and gas sales	**$23,685,000**	$23,269,000	**$68,934,000**	$67,710,000
Hedging gain (loss)	**109,000**	396,000	**924,000**	(695,000)
Royalties	**(2,682,000)**	(2,647,000)	**(9,128,000)**	(8,098,000)
Gain on sale of property	**–**	–	**–**	532,000
Alberta royalty tax credits	**–**	149,000	**–**	484,000
Interest and other	**9,000**	4,000	**42,000**	39,000
	21,121,000	21,171,000	**60,772,000**	59,972,000
Expenses				
Production costs	**6,401,000**	5,689,000	**18,538,000**	16,241,000
General and administrative	**773,000**	570,000	**1,864,000**	1,814,000
Interest on debt	**709,000**	414,000	**2,150,000**	1,068,000
Unit based compensation	**437,000**	332,000	**840,000**	697,000
Dry hole costs	**1,244,000**	–	**1,720,000**	–
Depletion, depreciation and accretion	**3,492,000**	3,219,000	**10,278,000**	8,726,000
	13,056,000	10,224,000	**35,390,000**	28,546,000
Earnings before Income Taxes	**8,065,000**	10,947,000	**25,382,000**	31,426,000
Income Taxes (Recovery)				
Current	**89,000**	97,000	**247,000**	287,000
Future	**(1,110,000)**	409,000	**2,705,000**	360,000
	(1,021,000)	506,000	**2,952,000**	647,000
Net Earnings for the Period	**9,086,000**	10,441,000	**22,430,000**	30,779,000
Deficit at beginning of period	**(42,489,000)**	(26,065,000)	**(37,245,000)**	(27,214,000)
Distributions declared	**(11,164,000)**	(11,899,000)	**(29,752,000)**	(31,088,000)
Deficit at End of Period	**($44,567,000)**	($27,523,000)	**($44,567,000)**	($27,523,000)
Net Earnings per Trust Unit – Basic (Note 6)	**$0.54**	$0.62	**$1.33**	$1.84
Net Earnings per Trust Unit – Diluted (Note 6)	**$0.54**	$0.62	**$1.32**	$1.82

Consolidated Statements of Unitholders' Equity

For the periods ended September 30 (unaudited)	Three Months		Nine Months	
	2007	2006	**2007**	2006
Unitholders' equity, beginning of period	**$51,920,000**	$61,202,000	**$53,359,000**	$57,322,000
Comprehensive income for the period	**9,487,000**	10,441,000	**23,148,000**	30,779,000
Adjustment of opening accumulated comprehensive income (Note 1)	**–**	–	**2,380,000**	–
Net capital contributions	**140,000**	311,000	**845,000**	2,677,000
Unit based compensation adjustment	**437,000**	332,000	**840,000**	697,000
Distributions declared	**(11,164,000)**	(11,899,000)	**(29,752,000)**	(31,088,000)
Unitholders' Equity, End of Period	**$50,820,000**	$60,387,000	**$50,820,000**	$60,387,000

Consolidated Statements of Comprehensive Income

For the periods ended September 30 (unaudited)	**Three Months**	**Nine Months**
	2007	**2007**
Net Earnings for the Period	**$9,086,000**	**$22,430,000**
Other Comprehensive Income, net of tax		
Unrealized gains and losses on investments (net of income taxes; Three months ended - $93,000, Nine months ended - $202,000)	**542,000**	**1,170,000**
Gains and losses on derivatives designated as cash flow hedges (net of income taxes; Three months ended - ($26,000), Nine months ended - $83,000)	**(64,000)**	**202,000**
Gains and losses on derivatives designated as cash flow hedges in prior periods transferred to net earnings in the current period (net of income taxes; Three months ended - ($32,000), Nine Months ended - ($268,000))	**(77,000)**	**(654,000)**
Changes in gains and losses on derivatives designated as cash flow hedges (net of income taxes; Three months ended - ($58,000), Nine months ended – ($185,000))	**(141,000)**	**(452,000)**
Other Comprehensive Income	**401,000**	**718,000**
Comprehensive Income	**$9,487,000**	**$23,148,000**

Consolidated Statements of Cash Flows

For the periods ended September 30 (unaudited)	Three Months		Nine Months	
	2007	2006	**2007**	2006
Operating Activities				
Net earnings for the period	**$9,086,000**	$10,441,000	**$22,430,000**	$30,779,000
Items not affecting cash				
Gain on sale of property	**–**	–	–	(532,000)
Unit based compensation	**437,000**	332,000	**840,000**	697,000
Dry hole costs	**1,244,000**	–	**1,720,000**	–
Depletion, depreciation and accretion	**3,492,000**	3,219,000	**10,278,000**	8,726,000
Future income taxes (recovery)	**(1,110,000)**	409,000	**2,705,000**	360,000
	13,149,000	14,401,000	**37,973,000**	40,030,000
Change in non-cash working capital				
Accounts receivable	**(230,000)**	665,000	**369,000**	955,000
Crude oil inventory	**(32,000)**	(33,000)	**33,000**	(186,000)
Parts inventory	**(65,000)**	116,000	**(41,000)**	112,000
Prepaid expenses	**266,000**	(73,000)	**(188,000)**	(604,000)
Accounts payable and accrued liabilities	**(979,000)**	(710,000)	**450,000**	105,000
Asset retirement obligations settled	**(223,000)**	(268,000)	**(532,000)**	(393,000)
	(1,263,000)	(303,000)	**91,000**	(11,000)
Cash Provided by Operating Activities	**11,886,000**	14,098,000	**38,064,000**	40,019,000
Financing Activities				
Increase in debt	**1,993,000**	6,183,000	**11,215,000**	17,525,000
Unit option proceeds	**140,000**	311,000	**845,000**	2,677,000
Unit distributions	**(11,164,000)**	(11,899,000)	**(33,802,000)**	(34,726,000)
Cash Used in Financing Activities	**(9,031,000)**	(5,405,000)	**(21,742,000)**	(14,524,000)
Investing Activities				
Property and equipment expenditures	**(2,763,000)**	(12,597,000)	**(12,087,000)**	(28,891,000)
Proceeds on sale of properties	**–**	–	**–**	750,000
Change in non-cash working capital				
Accounts receivable	**–**	379,000	**993,000**	(342,000)
Accounts payable and accrued liabilities	**(92,000)**	3,525,000	**(5,228,000)**	2,988,000
Cash Used in Investing Activities	**(2,855,000)**	(8,693,000)	**(16,322,000)**	(25,495,000)
Net Cash Inflow	**–**	–	**–**	–
Cash, beginning of period	**–**	–	**–**	–
Cash, End of Period	**$–**	$–	**$–**	$–
Cash Interest Paid	**$709,000**	$414,000	**$2,150,000**	$1,068,000
Cash Taxes Paid (Recovered)	**$90,000**	$102,000	**$273,000**	($292,000)

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 2006 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 2006 annual financial statements.

Financial instruments – recognition and measurement

On January 1, 2007, the Trust adopted Section 3855 of the Canadian Institute of Chartered Accounts' ("CICA") Handbook, "Financial Instruments – Recognition and Measurement" and Section 3861 Financial Instruments – Presentation and Disclosure. It sets out the standards for recognizing and measuring financial instruments in the balance sheet and the standards for reporting gains and losses in the financial statements. Financial assets available for sale, assets and liabilities held for trading and derivative financial instruments, part of a hedging relationship or not, have to be measured at fair value.

The Trust has made the following classifications:

- Investment in related party is classified as available-for sale and will thus be marked-to-market through comprehensive income at each period end.
- Accounts receivable are classified as loans and receivables and are recorded at amortized cost using the effective interest method. Gains and losses are recognized in net earnings when the asset is no longer recognized.
- Accounts payable and accrued liabilities and bank debt are classified as other financial liabilities and are recorded at amortized cost using the effective interest method. Gains and losses are recognized in net earnings when the liability is no longer recognized.

The adoption of this Section is done retroactively without restatement of the consolidated financial statements of prior periods. As of January 1, 2007, the impact on the consolidated balance sheet of measuring the investment in related party at marked-to-market was an increase of $1,836,000 to investment in a related party, an increase in future tax liability of $270,000 and an increase in accumulated other comprehensive income of $1,566,000.

The impact on the consolidated financial balance sheet of measuring hedging derivatives at fair value as at January 1, 2007 was an increase in other assets of $1,148,000, an increase in future tax liability of $334,000 and an increase in accumulated other comprehensive income of $814,000.

The Trust selected January 1, 2003 as its transition date for embedded derivatives. An embedded derivative is a component of a financial instrument or another contract of which the characteristics are similar to a derivative. This had no impact on the consolidated financial statements.

Comprehensive income

On January 1, 2007, the Trust adopted Section 1530 of the CICA Handbook, "Comprehensive Income". It describes reporting and disclosure recommendations with respect to comprehensive income and its components. Comprehensive income is the change in unitholders' equity, which results from transactions and events from sources other than the Trust's unitholders. These transactions and events include unrealized gains and losses from changes in fair value of certain financial instruments.

The adoption of this Section implied that the Trust now presents a consolidated statement of comprehensive income as a part of the consolidated financial statements.

Equity

On January 1, 2007, the Trust adopted Section 3251 of the CICA Handbook "Equity" replacing Section 3250 "Surplus". It describes standards for the presentation of equity and changes in equity for reporting periods as a result of the application of Section 1530 "Comprehensive Income".

Hedges

On January 1, 2007, the Trust adopted Section 3865 of the CICA Handbook "Hedges". The recommendations of this Section expand the guidelines required by Accounting Guideline 13(AcG-13), Hedging Relationships. This section describes when and how hedge accounting can be applied as well as the disclosure requirements. Hedge accounting enables the recording of gains, losses, revenues and expenses from the derivative financial instrument in the same period as those related to the hedge item.

Accounting changes

The Trust also adopted Section 1506, "Accounting Changes," whereby the only impact is to provide disclosure of when an entity has not applied a new source of GAAP that has been issued but is not yet effective. This is the case with Section 3862, "Financial Instruments Disclosures" and Section 3863, "Financial Instruments Presentations" which are required to be adopted for fiscal years beginning on or after October 1, 2007. The Trust will adopt these standards on January 1, 2008 and it is expected that the only effect on the Trust will be incremental disclosures regarding 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.

2. INVESTMENT IN RELATED PARTY

The investment consists of 689,682 (December 31, 2006 – 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 September 30, 2007, was $3,669,000 (December 31, 2006 - $2,297,000). The common shares trade on the Toronto Stock Exchange under the symbol CMF. The investment represents less than a two percent ownership in the outstanding shares of Comaplex.

3. PROPERTY AND EQUIPMENT

	September 30, 2007		December 31, 2006	
	Cost	**Accumulated Depletion and Depreciation**	Cost	Accumulated Depletion and Depreciation
Undeveloped land	**$ 334,000**	**$ –**	$ 334,000	$ –
Petroleum and natural gas properties and related equipment	**185,202,000**	**63,242,000**	175,353,000	54,008,000
Furniture, equipment and other	**990,000**	**667,000**	915,000	642,000
	$186,526,000	**$63,909,000**	$176,602,000	$54,650,000

4. DEBT

The Trust through its operating subsidiaries has a bank revolving credit facility of $69,900,000 at September 30, 2007 (December 31, 2006 - $59,900,000). 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 $340,000 were issued at September 30, 2007 (December 31, 2006 - $340,000). 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. The Trust has classified this debt as a current liability as required by generally accepted accounting principles. It has been management's experience that these types of loans which are required to be classified as a current liability are seldom called by principal bankers as long as all the terms and conditions of the loan are complied with. Cash interest paid during the nine month periods ended September 30, 2007 and 2006 for these loans were $2,150,000 and $1,068,000 respectively.

5. INCOME TAXES

The Trust has recorded a future income tax liability related to assets and liabilities and related tax amounts. The following figures reflect the consequences of the Canadian Federal Governments October 31, 2006 announcement on the future taxation of Income Trusts:

	September 30, 2007	December 31, 2006
Future income tax liability to assets and liabilities:	**$11,805,000**	$6,233,000
Future tax asset related to finance costs:	**(95,000)**	–
Future tax asset related to corporate tax losses carried forward in the subsidiary companies	**(4,796,000)**	(2,646,000)
	$ 6,914,000	$3,587,000

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

	2007	2006
Earnings before income taxes	**$25,382,000**	$31,426,000
Combined federal and provincial income tax rates	**32.38%**	34.97%
Income tax provision calculated using statutory tax rates	**8,219,000**	10,989,000
Increase (decrease) in taxes resulting from:		
Saskatchewan resource surcharge	**247,000**	287,000
Unit-based compensation	**272,000**	244,000
Non-deductible crown royalties	**–**	815,000
Resource allowance	**–**	(1,452,000)
Change in effective tax rate of the Trust	**3,801,000**	–
Trust income allocated to Unitholders	**(9,685,000)**	(10,098,000)
Others	**98,000**	(138,000)
Income tax expense	**$ 2,952,000**	$ 647,000

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:

	Rate of Utilization %	Amount
Undepreciated capital costs	20-100	$16,324,000
Canadian oil and gas property expenditures	10	1,665,000
Canadian development expenditures	30	29,526,000
Canadian exploration expenditures	100	93,000
Income tax losses carried forward [1]	100	16,367,000
		$63,975,000

[1] Income tax losses carried forward expire in 2014 ($635,000), 2015 ($3,574,000), 2026 ($4,826,000) and 2027 ($7,332,000).

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

	Rate of Utilization %	Amount
Canadian oil and gas property expenditures	10	$14,583,000
Finance costs	20	411,000
Eligible capital expenditures	7	354,000
		$15,348,000

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 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.

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 reversal of these temporary differences to be 31.5%. 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 September 30, 2007, the Trust has estimated the amount of its temporary differences which were previously not subject to tax and estimated the periods in which these differences will reverse. The Trust estimates that $12,070,000 net taxable temporary differences will reverse after January 1, 2011, resulting in an additional $3,801,000 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.

As the legislation gives rise to a change in the Trust's estimated future income tax liability in the period, the recognition of the additional liability is accounted for prospectively in the period and an additional $3,801,000 of future income tax expense has been recorded for the period.

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		
Balance, January 1, 2007	16,874,658	$89,488,000
Issued pursuant to Trust's unit option plan	47,000	845,000
Transfer of contributed surplus to unit capital	–	93,000
Balance, September 30, 2007	16,921,658	$90,426,000

The number of trust units used to calculate diluted net earnings per unit for the period ended September 30, 2007 of 16,941,635 (2006 – 16,809,422) included the basic weighted average number of units outstanding of 16,907,105 (2006 – 16,703,957) plus 34,530 (2006 – 105,465) units related to the dilutive effect of unit options.

The deficit balance is composed of the following items:

	September 30, 2007	September 30, 2006
Accumulated earnings	**$144,836,000**	$115,935,000
Accumulated cash distributions	**(189,403,000)**	(143,458,000)
Deficit	**($44,567,000)**	($27,523,000)

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,692,000 (December 31, 2006 – 1,687,000) 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 September 30, 2007 and December 31, 2006, and changes during the nine month and twelve month periods ending on those dates is presented below:

	September 30, 2007		December 31, 2006	
	Options	**Weighted-Average Exercise Price**	Options	Weighted-Average Exercise Price
Outstanding at beginning of period	**721,500**	**$26.55**	646,000	$18.67
Options granted	**546,000**	**28.12**	447,000	29.18
Options exercised	**(47,000)**	**17.97**	(339,500)	15.20
Options cancelled	**(44,000)**	**27.92**	(32,000)	24.70
Outstanding at end of period	**1,176,500**	**$27.57**	721,500	$26.55
Options exercisable at end of period	**229,500**	**$24.56**	212,500	$22.62

The following table summarizes information about unit options outstanding at September 30, 2007:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 9/30/07	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable At 9/30/07	Weighted-Average Exercise Price
$22.45-$23.35	231,500	1.5 years	$23.32	194,500	$23.31
$24.20-$25.00	20,000	2.3 years	24.21	–	–
$26.60	5,000	2.3 years	26.60	–	–
$28.30-$28.75	880,000	2.2 years	28.49	15,000	28.72
$32.00-$33.75	40,000	2.2 years	33.55	20,000	33.55
$22.45-$33.75	1,176,500	2.1 years	$27.57	229,500	$24.56

The Trust records a compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants.

7. ACCUMULATED OTHER COMPREHENSIVE INCOME

Nine months ended September 30, 2007

	Opening	Other Comprehensive Income	Ending
Unrealized gains and losses on available-for sale financial assets	$1,566,000	$1,170,000	$2,736,000
Unrealized gains and losses on derivatives designated as cash flow hedges	814,000	(452,000)	362,000
	$2,380,000	$ 718,000	$3,098,000

8. RELATED PARTY TRANSACTIONS

The Trust received a management fee from Comaplex of $225,000 (2006 - $225,000) for management services, accounting services and office administration. This cost has been included as a recovery of general and administrative expenses. The above charge represents the fair value of the services rendered. At September 30, 2007 the Trust had an accounts receivable from Comaplex of $121,000 (December 31, 2006 - $38,000).

The Trust received a management fee from Pine Cliff Energy Ltd. (Pine Cliff) of $162,000 (2006 - $162,000) for management services, accounting services and office administration. This fee has been included as a recovery in general and administrative expenses. As at September 30, 2007 the Trust had no amounts for accounts receivable from or accounts payable to Pine Cliff. The above charge represents the fair value of the services rendered.

9. COMMITMENTS – FUTURE SALES AGREEMENTS

The Trust entered into the following commodity hedging contracts for a portion of its 2007 and 2008 production:

Period of Agreement	Commodity	Volume per day	Index	Price (Cdn.)
July 1, 2007 to December 31, 2007	Crude Oil	500 barrels	WTI	Floor of $75.00 and ceiling of $93.00 per barrel
July 1, 2007 to December 31, 2007	Crude Oil	500 barrels	WTI	Floor of $70.00 and ceiling of $80.06 per barrel
January 1, 2008 to June 30, 2008	Crude Oil	1,000 barrels	WTI	Floor of $73.00 and ceiling of $83.00 per barrel
July 1, 2008 to December 30, 2008	Crude Oil	500 barrels	WTI	Floor of $73.00 and ceiling of $80.68 per barrel
April 1, 2007 to October 31, 2007	Natural Gas	1,000 GJ's	AECO	Floor of $6.50 and ceiling of $9.20 per GJ
November 1, 2007 to March 31, 2008	Natural Gas	2,000 GJ's	AECO	Floor of $6.50 and ceiling of $10.37 per GJ

10. SUBSEQUENT EVENT – DISTRIBUTIONS

Subsequent to September 30, 2007, the Trust declared distributions of $0.22 per unit payable on October 31 and November 30, 2007 to Unitholders of record on October 15 and November 15, 2007 respectively. The distributions represent amounts related to September and October 2007 operations.

Bonterra
Energy Income Trust

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