



For Immediate Release
TSX: TUI.UN

TRUE ENERGY TRUST ANNOUNCES YEAR END 2008 FINANCIAL RESULTS

March 16, 2009 – (TSX: TUI.UN) True Energy Trust (“True,” “Company” or the “Trust”) announces its financial and operating results for the year ended December 31, 2008.

HIGHLIGHTS

	Years ended December 31,		
	2008	2007	
FINANCIAL (unaudited)			
<i>(CDN\$000s except unit and per unit amounts)</i>			
Revenue (before royalties and hedging ⁽¹⁾)	265,385	258,490	
Funds flow from operations ⁽²⁾	77,893	101,172	
Per basic trust unit	\$0.99	\$1.33	
Per diluted trust unit ⁽⁵⁾	\$0.98	\$1.33	
Net loss	(19,590)	(24,267)	
Per basic trust unit	\$(0.25)	\$(0.32)	
Per diluted trust unit ⁽⁵⁾	\$(0.25)	\$(0.32)	
Distributions declared	36,334	73,451	
Per unit	\$0.46	\$0.96	
Exploration and development	36,699	87,347	
Corporate and property acquisitions	6,303	1,505	
Capital expenditures – cash	43,002	88,852	
Property dispositions – cash	(44,340)	(31,808)	
Other – non-cash	3,710	(530)	
Total capital expenditures – net	2,372	56,514	
Long-term debt	132,388	168,475	
Convertible debentures ⁽³⁾	81,124	79,407	
Working capital deficiency	1,492	2,431	
Total net debt ⁽³⁾	215,004	250,313	
Total assets	736,117	880,252	
Unitholders' equity	406,461	462,780	
OPERATING			
Daily sales volumes			
Crude oil, condensate and NGLs	(bbls/d)	4,333	5,330
Natural gas	(mcf/d)	45,202	64,853
Total oil equivalent	(boe/d)	11,867	16,139
Average prices			
Crude oil, condensate and NGLs	(\$/bbl)	76.75	48.71
Crude oil, condensate and NGLs (including hedging ⁽¹⁾)	(\$/bbl)	64.24	47.74
Natural gas	(\$/mcf)	8.50	6.73
Natural gas (including hedging ⁽¹⁾)	(\$/mcf)	8.00	7.08
Total oil equivalent	(\$/boe)	60.42	43.13
Total oil equivalent (including hedging ⁽¹⁾)	(\$/boe)	53.92	44.23

		Years ended December 31,	
		2008	2007
Statistics			
Operating netback ⁽⁴⁾	(\$/boe)	30.91	22.21
Operating netback ⁽⁴⁾ (including hedging ⁽¹⁾)	(\$/boe)	24.41	23.31
Transportation	(\$/boe)	1.62	1.35
Production expenses	(\$/boe)	15.33	11.59
General & administrative	(\$/boe)	3.67	3.09
Royalties as a % of sales after transportation		21%	19%

TRUST UNITS

Trust units outstanding	78,496,581	79,216,046
Trust unit incentive rights outstanding	2,700,500	5,931,997
Units issuable for exchangeable shares	300,433	335,793
Units issuable for convertible debentures	5,390,625	5,390,625
Diluted trust units outstanding	86,888,139	90,874,461
Diluted weighted average trust units ⁽⁵⁾	78,985,481	75,792,488

TRUST UNIT TRADING STATISTICS

(CDN\$, except volumes) based on intra-day trading

High	4.69	7.47
Low	1.17	2.76
Close	1.20	3.35
Average daily volume	270,458	492,004

⁽¹⁾ The Trust has entered into various commodity risk management contracts which are considered to be economic hedges. Per unit metrics after hedging includes only the realized portion of gains or losses on commodity contracts.

Effective January 1, 2007 on adoption of CICA handbook sections 3855 and 3865, the Trust no longer applies hedge accounting to these contracts. As such, these contracts are revalued to fair value at the end of each reporting date. This results in recognition of unrealized gains or losses over the term of these contracts which is reflected each reporting period until these contracts are settled, at which time realized gains or losses are recorded. These unrealized gains or losses on commodity contracts are not included for purposes of per unit metrics calculations disclosed.

⁽²⁾ The highlights section contains the term "funds flow from operations" (or as commonly referred to as "cash flow from operations"), which should not be considered an alternative to, or more meaningful than cash flow from operating activities as determined in accordance with Canadian generally accepted accounting principles ("GAAP") as an indicator of the Trust's performance. Therefore reference to diluted funds flow from operations or funds flow from operations per trust unit may not be comparable with the calculation of similar measures for other entities. Management uses funds flow from operations to analyze operating performance and leverage and considers funds flow from operations to be a key measure as it demonstrates the Trust's ability to generate the cash necessary to fund future capital investments and to repay debt. The reconciliation between funds flow from operations and cash flow from operating activities can be found in the Management Discussion and Analysis ("MD&A"). Funds flow from operations per trust unit is calculated using the weighted average number of trust units for the period.

⁽³⁾ Net debt includes the net working capital deficiency (excess) before short-term commodity contract assets and liabilities and short-term future income tax assets and liabilities. Total net debt also includes the liability component of convertible debentures and excludes asset retirement obligations and the future income tax liability.

⁽⁴⁾ Operating netbacks are calculated by subtracting royalties, transportation, and operating costs from revenues.

⁽⁵⁾ In computing weighted average diluted earnings per trust unit for the year ended December 31, 2008 a total of 2,700,500 (2007: 5,931,997) trust incentive units, 300,433 (2007: 335,793) exchangeable shares and 5,390,625 (2007: 5,390,625) trust units issuable pursuant to the conversion of convertible debentures were excluded from the calculation for the years ended December 31, 2008 and 2007 as they were not dilutive.

To calculate weighted average diluted funds flow from operations for the year ended December 31, 2008, a total of 300,433 (2007: nil) exchangeable shares were added to the denominator, resulting in diluted weighted average trust units of 79,285,914 and funds flow from operations per diluted trust unit of \$0.98 under this calculation. Under this calculation, a total of 2,700,500 (2007: 5,931,997) trust incentive units and 5,390,625 (2007: 5,390,625) trust units issuable pursuant to the conversion of convertible debentures were excluded from the calculation for the years ended December 31, 2008 and 2007 as they were not dilutive.

REPORT TO UNITHOLDERS

True's Management and directors recognized, in 2006, the vulnerability inherent with a weak balance sheet and set a goal of reducing the Company's total net debt to ensure the Trust's long term financial flexibility. The successful corporate strategy employed included divesting a segment of the company's production base coupled with reducing distributions to \$0.04 per unit effective December 2007. These efforts culminated in the Trust decreasing total net debt from \$275.8 million in December 2006 by \$60.8 million exiting 2008 with total net debt of \$215.0 million. Unfortunately throughout the second half of 2008 industry witnessed fierce erosion of commodity pricing with an ensuing severe energy bear equity market. As a consequence the Trust further decreased distributions in December 2008 to \$0.02 per unit, diminishing annual cash distribution paid in 2008 to \$0.46 per unit.

Further on February 9, 2009 as economic conditions continued to deteriorate driven by significant declining crude oil prices, a weakening outlook for natural gas demand and heightened risk in the credit markets, the Company deemed it prudent to suspend its distribution as of February 2009 to maintain corporate liquidity during the current financial turmoil and prevailing commodity price environment. Distributions continue to be reviewed monthly in context of commodity prices, among other factors, and are subject to revision by our Board of Directors.

True continues to also tighten the cost structure of our business with forecasted cuts from 2008 levels of approximately 30% to total operating expenses which includes general and administrative costs (G&A) and lease operating costs in 2009. The Trust's capital program has been restricted to \$15 million and the Company is forecasting 2009 production volumes to average approximately 10,000 boe/d.

Additional protection of the cash flow forecasts was achieved by hedging approximately 60% of True's estimated 2009 natural gas production for the period of March 1, 2009 to September 30, 2009 and 49% for the fourth quarter of 2009 at a combined average fixed price of \$6.42 CAD per GJ (\$7.06/mcf), and approximately 18% of True's estimated natural gas production is hedged for the first half of 2010 at an average price of \$7.25 CAD per GJ (\$7.96/mcf). The addition of a recent crude oil price collar effectively hedges approximately 13% of True's estimated 2009 crude oil production. True maintains an active commodity price risk management program focused on maintaining sufficient cash flow to fund its operations.

True's operating forecast for 2009 which assumes a CAD\$/US\$ exchange rate of \$0.82, West Texas Intermediate ("WTI") oil price ranging from US\$50.00/bbl to US\$55.00/bbl, AECO natural gas price ranging from CAD\$5.00/GJ (\$5.50/mcf) to CAD\$5.92/GJ (\$6.50/mcf) and average annual production of approximately 10,000 boe/d generates cash flow from operations ranging from \$30 million to \$40 million, after deducting royalties, all operating costs, G&A and debt servicing costs. Based on the foregoing assumptions and assuming 2009 distributions of \$1.6 million coupled with the planned capital budget of \$15 million the Trust would utilize approximately 55% of the Trust's forecasted cash flow from operations on the low side case ensuring liquidity if commodity prices continue to weaken.

Financial

Highlights:

1. Total net proceeds from the sale of properties in 2008 were \$44.3 million; which was used to pay down debt.
2. True's total net debt including the liability component of its convertible debentures, excluding unrealized commodity contract assets and liabilities, future income taxes and asset retirement obligations, as at December 31, 2008 was \$215.0 million, down from \$250.3 million as at December 31, 2007 and \$275.8 million as at December 31, 2006. The convertible debentures have a maturity date of June 30, 2011.
3. As at December 31, 2008, True has approximately \$132.4 million drawn on its extendible, revolving bank credit facility leaving \$19.6 million available to assist in managing our operations and capital program.
4. The Trust and operating subsidiaries of the Trust have approximately \$495 million in tax pools available for deduction against future income.

Funds flow from operations for the 2008 year was \$77.9 million on gross sales of \$265.4 million compared to funds flow from operations of \$101.2 million on gross sales of \$258.5 million for the same period in 2007. The decrease in funds flow for the 2008 year compared to 2007 was primarily the result of lower sales volumes and higher realized hedging losses in 2008, despite improved commodity pricing and operating netbacks.

Funds flow from operations for the 2008 fourth quarter was \$5.9 million on gross sales of \$41.0 million compared to funds flow from operations of \$19.5 million on gross sales of \$61.8 million for the same period in 2007. This was reflective of lower commodity prices, lower sales volumes and higher costs in 2008. Overall commodity prices for the fourth quarter of 2008 decreased significantly from that seen earlier in 2008 in connection with the current global

economic crisis. Crude oil prices in the month of December 2008 declined to a low of under US\$40 WTI, a level not seen since 2004. Fourth quarter 2008 funds flow from operations also includes \$1.0 million of charges associated with severance costs.

True maintains a commodity price risk management program to provide a measure of stability to funds flow from operations. Unrealized mark-to-market gains or losses are non-cash adjustments to the current fair market value of the contract over its entire term and are included in the calculation of net loss.

The net loss for the 2008 year was \$19.6 million compared to a net loss of \$24.3 million for 2007. The decrease in the net loss from 2007 to 2008 was primarily due to reduced non-cash charges for depletion, depreciation and accretion, higher unrealized gains on commodity contracts, offset by a reduced future income tax recovery and lower funds flow from operations. The net loss for the 2008 fourth quarter was \$9.5 million compared to a net loss of \$0.4 million in the same period in 2007. The net loss for the 2008 fourth quarter was impacted by reduced funds flow from operations, partly offset by a \$7.4 million unrealized mark-to-market gain on commodity contracts.

Liquidity

As an oil and gas business, the Trust has a declining asset base and therefore relies on ongoing development and acquisitions to replace production and add additional reserves. Future oil and natural gas production and reserves are highly dependent on the success of exploiting the Trust's existing asset base and in acquiring additional reserves. To the extent the Trust is successful or unsuccessful in these activities; funds flow could be increased or reduced.

The Trust generally relies on operating cash flows and the bank loan to fund capital requirements and provide liquidity. From time to time, the Trust accesses capital markets to meet its additional financing needs and to maintain flexibility in funding its capital programs. Future liquidity depends primarily on cash flow generated from operations, existing credit facilities and the ability to access debt and equity markets.

The Trust's capital structure includes a revolving bank credit facility and unsecured subordinated convertible debentures. The 7.5% unsecured convertible debentures represents approximately 37% of the Trust's total net debt and these debentures are due July 2011. Upon maturity or redemption of these debentures, the Trust can be pay the outstanding principal or premium (if any) in cash or, subject to regulatory approval, through the issuance of additional Trust units at 95% of a weighted average trading price of the Trust units. True's extendible, revolving bank credit facility was renewed on June 27, 2008 with an authorized loan amount of \$152 million and consists of a \$15 million demand operating facility and a \$137 million extendible revolving term syndicated credit facility. True's authorized loan amount was confirmed at \$152 million effective September 30, 2008 with the next borrowing base review scheduled for March 31, 2009. The borrowing base will be subject to the lending syndicate's determination which is based upon the latest reserves information, their internal commodity price decks and other factors. In the event the borrowing base is lowered below the drawn credit facility at that time, any shortfall would be required to be repaid within 60 days of notification, or as otherwise agreed by the lending syndicate, and this funding would currently be expected to come from alternative sources of debt or equity financing or the proceeds from asset dispositions as available. The revolving period ends on June 26, 2009, unless extended for a further 364 day period. Should the facilities not be renewed they convert to a 366 day non-revolving credit facility. \$12.5 million of the syndicated facility is with a US bank which may be required to be repaid or reallocated to one or more of the other four current members of the syndicate or a new member on June 28, 2009. As at December 31, 2008, True had approximately \$19.6 million available under the facility to assist in managing our operations and capital program. True is fully compliant with all of its debt covenants.

True's total net debt, excluding unrealized commodity contract assets and liabilities, future income taxes and asset retirement obligations, as at December 31, 2008, was \$215.0 million, representing \$132.4 million outstanding on the credit facility, \$81.1 million in convertible debentures (liability component) and a \$1.5 million working capital deficiency.

Combined funding requirements for distributions declared and True's capital expenditures represented approximately 102% of funds flow from operations in the twelve months ended December 31, 2008. Budgeted reduced capital spending and distributions during the year mitigated the reduced annual cash flows, primarily as a result of crude oil price declines experienced in the later half of 2008.

There are currently no capital commitments, other than those associated with the Trust's credit facilities outlined above and its 2009 drilling and exploration program of \$3 million for the first half of 2009. The Trust continually monitors its capital spending program in light of the recent volatility with respect to commodity prices and Canadian dollar exchange rates with the aim of ensuring the Trust will be able to meet future anticipated obligations incurred from normal ongoing operations with funds flow from operations and draws on the Trust's syndicated facility, as necessary.

In August 2008, the Trust announced approval of the renewal of its normal course issuer bid ("NCIB") program to repurchase up to 7.8 million of its outstanding trust units during the period August 28, 2008 through August 27, 2009, subject to certain restrictions. As of December 31, 2008, the Trust has purchased 615,100 trust units at a weighted average price of \$2.74 per trust unit under the NCIB renewed on August 28, 2008. This purchase is in response to True's belief that the current market price for Trust units does not reflect the underlying value of the Trust and the cancellation of the above purchased Trust units will increase the proportionate interest of, and be advantageous to, all remaining unitholders. Future repurchases will be dependent on excess cash available after consideration of the Trust's priority uses of cash and the trading price of the Trust's units relative to the net asset value of the Trust.

In November 2008, the Trust received Toronto Stock Exchange approval for its normal course issuer bid program to repurchase up to 10% of the issued and outstanding 7.50% convertible unsecured subordinated debentures of the Trust ("Debentures") from December 1, 2008 to November 30, 2009. True believes that, from time to time, the market price of the Debentures may not fully reflect the underlying value of the Debentures and that at such times the purchase of the Debentures would be in the best interests of the Trust. Such purchases will increase the proportionate interest of, and may be advantageous to, all remaining holders of Debentures as well as holders of Trust units. To date, there have been no repurchases of the Debentures under this NCIB.

True does not hold any Asset-Backed Commercial Paper investments. As a non-operating working interest owner, True has a minor exposure of approximately \$70,000 from oil sales marketed through SemCanada Crude Company, which filed for CCAA protection on July 22, 2008. True does not have any exposure to Lehman Brothers, which filed for Chapter 11 bankruptcy protection in the United States. To the best of True's knowledge, the Trust does not have any exposure to other US financial institutions.

True maintains an active commodity price risk management program. The Trust will continue its hedging strategies focusing on maintaining sufficient cash flow to fund True's operations.

In addition to the Trust's financial commodity risk management contracts, the Trust has entered into a natural gas physical delivery sales contract to sell 5,275 GJ/day at a fixed price of \$7.29/GJ and \$7.90/GJ for the third and fourth quarter of 2009, respectively.

Property Acquisition and Dispositions

On October 1, 2008, True closed the purchase of further working interests in the Mantario, Saskatchewan area for \$4.3 million in cash after adjustments. Effective October 1, 2008 this tuck-in acquisition added approximately 225 bbls/d of heavy oil production for metrics of \$19,100/boe/d and \$8.60/boe.

During the first quarter of 2008, True was successful in completing the divestiture of a non-core property in Northeast Alberta for net proceeds of \$5.8 million. During the second quarter of 2008, True disposed of its Dodsland-Stranraer property located in Saskatchewan for net proceeds of \$38.5 million. Total net proceeds from the sale of properties in the 2008 were \$44.3 million; the net proceeds from the dispositions were used to pay down debt.

Reserves and Production

Highlights from True's December 31, 2008 reserves include:

1. True's net asset value, based on GLJ Petroleum Consultants Ltd. ("GLJ") reserve report evaluation at a 10% discount rate, equates to \$4.98 per unit and \$4.96 per fully diluted unit.
2. The Trust's reserves life index has extended to 6.4 years for proved reserves and 10.1 years for proved plus probable reserves.
3. The Trust recorded all-in annual Finding, Development and Acquisition ("FD&A") cost of \$18.20 per barrel of oil equivalent ("boe") in 2008 before consideration of future development capital ("FDC") for proved reserves category. This is a 51 percent reduction from the \$37.30 per boe FD&A cost realized in 2007. Including FDC, the FD&A cost was \$20.90 per boe. The three year average FD&A cost is \$36.70 per boe for the proved category before FDC; including FDC, the three year average FD&A cost is \$30.40 per boe.
4. The Trust established a recycle ratio, after hedging and excluding future development costs, of 1.34x on a proved basis and 0.77x on a proved and probable basis.
5. Total proved plus probable Company Interest Reserves, including all royalties receivable but before deducting royalty burdens, as evaluated by GLJ at December 31, 2008 were 39,488 mboe (gas converted 6:1).

6. Based on the reserves information and other data as at December 31, 2008, the Trust has performed ceiling test calculations in accordance with the requirements of CICA AcG 16 "Oil and Gas Accounting – Full Cost." No ceiling test impairment of oil and gas properties was identified for accounting purposes as at December 31, 2008.

For additional information please refer to the reserves news release dated February 9, 2009 (posted on www.sedar.com).

For the 2008 year, sales volumes averaged 11,867 boe/d compared to 14,937 boe/d that was produced in Q4 of 2007. The reduction in average sales volumes is a result of natural production decline, minimal 2008 capital spending and the impact of dispositions totaling approximately 1,000 boe/d that were closed during the first half of 2008. Effective October 1, 2008, True closed the purchase of further working interests in the Mantario, Saskatchewan area for \$4.3 million in cash after adjustments. This tuck in acquisition added approximately 225 bbls/d of heavy oil production for metrics of \$19,100 per boe/d.

2008 fourth quarter sales volumes averaged 10,750 boe/d. True's production and operations have been negatively impacted by the extreme weather conditions experienced in western Canada in December 2008 and extending into January 2009.

Based on minimal capital spending, and normal production declines, 2009 production volumes are anticipated to average approximately 10,000 boe/d.

Drilling

During the 2008 year, True had an interest in a total of 38 (17.1 net) wells drilled, which resulted in 7.1 net natural gas wells, 4.0 net light oil wells, 0.8 net heavy oil well and 1.0 net water disposal well. 4.2 net wells were dry and abandoned.

Included in the above were nine gross natural gas wells that evaluated True land at no cost to the Company. In eight True has an overriding royalty; in the other True has no capital cost to drill, complete and tie in, retaining a 20% working interest from first production. True has over 377,000 net acres of undeveloped mineral leases in Alberta, British Columbia and Saskatchewan as of December 31, 2008. An integral component of our growth strategy is to aggressively farmout our interest in non core areas.

During the fourth quarter of 2008, True drilled or participated in 10 (5.1 net) wells including 3.1 net natural gas wells, and 2.0 net light oil wells. Fourth quarter drilling was focused on the Kerrobert Viking horizontal light oil wells in Kindersley and conventional natural gas drilling at Saddle Lake in North East Alberta. 1.0 net wells from the Saddle Lake drilling program are expected to be tied in during the first quarter of 2009.

During the fourth quarter of 2008, True was successful in farming out its interest in 12,700 net acres located in British Columbia. The arrangement will see True carried through the drilling and completion phases of the program with the ability to retain a small working interest and remain involved in a key high impact, high cost Montney play.

Disposition of Working Interest in Block 126 Peru

As announced on November 24, 2008, True and Petrominerales Ltd. (TSX:PMG), a 76.4% owned subsidiary of Petrobank Energy and Resources Ltd., have entered into an agreement whereby Petrominerales will acquire True's 10% working interest and will be designated the operator of Block 126 located in the Ucayali Basin of east central Peru. A wholly-owned subsidiary of True held the 10% working interest and is the operator in a partnership with Veraz Petroleum Ltd. ("Veraz"). Closing of this transaction is subject to the consent of Perupetro S.A, the private law state company responsible for promoting the investment of hydrocarbon exploration and exploitation activities in Peru and receipt of the purchase price according to the agreement. True continues to have a minor investment in Veraz.

2009 Outlook

The global economic contraction has caused oil and gas prices to plummet producing both, a sector wide severe bear equity market and substantially decreasing cash flow. The consequences are being felt industry wide with slashed capital programs coupled with suppressed expense budgets. True has adopted a very cautious outlook with material reductions in its operating cost base.

True has targeted reductions in general and administrative expenses early in 2009 and we will continue to focus on opportunities to reduce operating costs. As part of the general and administrative cost reductions, True has

streamlined its operations and reduced head office staffing levels by a third. True has forecasted cuts of 30% to total operating expenses, which includes general and administrative costs and lease operating costs, in 2009. Cost reductions in combination with limiting our capital spending in the first half of 2009 will add to our financial flexibility and better position True to operate in the current difficult economic environment.

True does not intend to drill any operated wells in the first half of 2009. Furthermore, capital spending will be limited to \$3 million during the first six months of 2009. In addition to focusing on increasing production from existing wells through continued optimization, and performing necessary maintenance programs, the first half 2009 capital spending will be limited to the tie-in of two gross (1 net) Saddle Lake area natural gas wells drilled in the fourth quarter of 2008. Non-operated projects will continue to be closely scrutinized against internal opportunities. True's total 2009 capital program is not expected to exceed \$15 million and will reflect our future view of commodity pricing and cash flow, available business opportunities, and industry costs trends.

The Company has reorganized its senior management with the appointment of myself as President and CEO, Mr. Russell G. Oicle as Vice President, Exploration and Mr. Duncan A. Chisholm, as Vice President, Operations. This group brings in excess of 100 years of experience and expertise to True as successful full cycle explorationists and production optimization specialists.

With a cautious bias to cost control, the Company will proceed in 2009 to explore its quality land base while high grading the plethora of low risk development opportunities.

A conference call to discuss True's annual financial and reserves results will be held on March 17, 2009 at 2:00 PM MDT/4:00 PM EDT. To participate, please call toll-free 1-800-731-5774 or 416-644-3423. The conference call will also be recorded and available by calling 1-877-289-8525 or 416-640-1917 and entering passcode 21295355 followed by the pound sign.

True's annual general meeting is scheduled for 3:00pm on May 20, 2009 in the Herald Doll Room at the Hyatt Regency in Calgary.

Raymond G. Smith, P. Eng.
President and CEO
March 16, 2009

MANAGEMENT'S DISCUSSION AND ANALYSIS

March 16, 2009 – The following Management's Discussion and Analysis of financial results as provided by the management of True Energy Trust ("True" or the "Trust") should be read in conjunction with the audited consolidated financial statements of the Trust for the years ended December 31, 2008 and 2007. This commentary is based on information available to, and is dated as of, March 16, 2009. The financial data presented is in accordance with Canadian generally accepted accounting principles ("GAAP") in Canadian dollars, except where indicated otherwise.

CONVERSION: The term barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 mcf/bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in this report are derived from converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil.

NON-GAAP MEASURES: This Management's Discussion and Analysis contains the term "funds flow from operations" (or also commonly referred to as "cash flow from operations"), which should not be considered an alternative to, or more meaningful than "cash flow from operating activities" as determined in accordance with Canadian GAAP as an indicator of the Trust's performance. Therefore reference to funds flow from operations or funds flow from operations per unit may not be comparable with the calculation of similar measures for other entities. Management uses funds flow from operations to analyze operating performance and leverage and considers funds flow from operations to be a key measure as it demonstrates the Trust's ability to generate the cash necessary to fund future capital investments and to repay debt. The reconciliation between funds flow from operations and cash flow from operating activities can be found in the Management's Discussion and Analysis. Funds flow from operations per unit is calculated using the weighted average number of units for the period.

This Management's Discussion and Analysis also contains other terms such as total net debt and operating netbacks, which are not recognized measures under Canadian GAAP. Total net debt is calculated as long-term debt plus the liability component of the convertible debentures and the net working capital deficiency (excess) before short-term commodity contract assets and liabilities and short-term future income tax assets and liabilities. Operating netbacks are calculated by subtracting royalties, transportation, and operating expenses from revenues. Management believes these measures are useful supplemental measures of firstly, the total amount of current and long-term debt and secondly, the amount of revenues received after transportation, royalties and operating expenses. Readers are cautioned, however, that these measures should not be construed as an alternative to other terms such as current and long-term debt or net income determined in accordance with GAAP as measures of performance. True's method of calculating these measures may differ from other entities, and accordingly, may not be comparable to measures used by other trusts or companies.

Additional information relating to the Trust, including the Trust's Annual Information Form, is available on SEDAR at www.sedar.com.

FORWARD LOOKING STATEMENTS: Certain information contained herein may contain forward looking statements including management's assessment of future plans and operations, drilling and tie-in plans and the timing thereof, plans regarding wells to be drilled, expected or anticipated production rates, hedging strategies, distributions and method of funding thereof, anticipated liquidity of the Trust and various matters that may impact such liquidity, timing of bringing production back on from certain wells, planned reductions in operating expenses in 2009 and expected operating expenses, expected production and transportation expenses and general and administrative expenses, expected levels of revenues and operating netbacks in 2009 compared to 2008, proportion of distributions anticipated to be taxable and non-taxable, maintenance of productive capacity and capital expenditures and the nature of capital expenditures and the timing and method of financing thereof, may constitute forward-looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources. The recovery and reserve estimates of True's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Events or circumstances may cause actual results to differ materially from those predicted, as a result of the risk factors set out and other known and unknown risks, uncertainties, and other factors, many of which are beyond the control of True. In addition, forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Included herein is an estimate of True's cash flow from operations in 2009 and the percentage that 2009 assumed distributions and its planned capital budget will be of such estimated funds flow from operations. Such financial outlook was approved by management of the Trust on February 9, 2009 and such financial outlook is included herein to provide an assessment of the ability of the Trust to generate the cash

necessary to fund future capital investments after assumed distribution and to repay debt. Although the Trust believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because the Trust can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified herein, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which the Trust operates; the timely receipt of any required regulatory approvals; the ability of the Trust to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Trust has an interest in to operate the field in a safe, efficient and effective manner; the ability of the Trust to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Trust to secure adequate product transportation; future commodity gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Trust operates; and the ability of the Trust to successfully market its oil and natural gas products. Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which have been used. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Additional information on these and other factors that could effect True's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), at True's website (www.trueenergytrust.com). Furthermore, the forward-looking statements contained herein are made as at the date hereof and True does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

The reader is further cautioned that the preparation of financial statements in accordance with GAAP requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based upon available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available, and as the economic environment changes.

Overview and Description of the Business

True Energy Trust is a Canadian trust, formed in 2005 via the reverse takeover of TKE Energy Trust. The Trust is involved in the exploration, development and production of petroleum and natural gas in western Canada. The Trust has a significant multi-year drilling inventory of locations in Alberta, Saskatchewan and British Columbia.

True's Trust units and convertible debentures are listed on the Toronto Stock Exchange under the symbols TUI.UN and TUI.DB, respectively.

Fourth Quarter 2008

Funds flow from operations during the fourth quarter of 2008 was \$5.9 million, a decrease of 70% compared to \$19.5 million for the fourth quarter of 2007. This was reflective of lower commodity prices, lower sales volumes and higher costs in 2008. Overall commodity prices for the fourth quarter of 2008 decreased significantly from that seen earlier in 2008 in connection with the current global economic crisis. Crude oil prices in the month of December 2008 declined to a low of under US\$40 WTI, a level not seen since 2004. Fourth quarter 2008 funds flow from operations also includes \$1.0 million of charges associated with severance costs. By comparison, in the last quarter of 2008, True had a net loss of \$9.5 million compared to a net loss of \$0.4 million in the fourth quarter of 2007.

Sales volumes for the three months ended December 31, 2008 averaged 10,750 boe/d, down 28% from the 14,937 boe/d produced in the fourth quarter of 2007. Fourth quarter 2008 sales volumes were lower than the same period in 2007 due to natural production declines, decreased production due to property dispositions during 2008, extreme weather conditions, and minimal capital spending.

In the fourth quarter of 2008, average sales volumes decreased 5% from the third quarter 2008 average volumes of 11,263 boe/d. True's production and operations were impacted by the extreme weather conditions and commodity price erosion experienced in western Canada in December 2008 and extending into January 2009. True realized the loss of an estimated 950 boe/d which was directly related to both weather and True's ongoing review of profitability. True continues to apply good winter operating practices to remedy the offline production, however, an estimated 250

boe/d will be reactivated upon receiving improved commodity prices. Natural gas sales averaged 38.4 Mmcf/d during the last quarter of 2008, compared to 57.4 Mmcf/d in the fourth quarter of 2007. The Trust's natural gas sales reduction was in part attributed to a Saskatchewan asset divestiture. The weighting toward natural gas averaged 60% in the fourth quarter, compared to 64% in the corresponding period of 2007. Crude oil, condensate and NGL sales volumes averaged 4,347 bbls/d in the fourth quarter of 2008 compared to 5,370 bbls/d during the same period of 2007.

During the fourth quarter of 2008, True spent \$11.0 million on capital projects, excluding corporate and asset acquisitions and dispositions, compared to \$15.5 million in 2007. In the fourth quarter of 2008, True drilled or participated in 10 (5.1 net) wells including 3.1 net natural gas wells, and 2.0 net light oil wells. Fourth quarter drilling was focused on the Kerrobert Viking horizontal light oil wells in Kindersley and conventional natural gas drilling at Saddle Lake in North East Alberta. 1.0 net well from the Saddle Lake drilling program is expected to be tied in during the first quarter of 2009. Also, during the fourth quarter of 2008, True was successful in farming out its interest in 12,700 net acres located in British Columbia. The arrangement will see True carried through the drilling and completion phases of the program with the ability to retain a small working interest and remain involved in a key Montney formation play.

During the fourth quarter of 2008, True experienced an overall decrease of 41% in commodity prices, based on decreases in crude oil, condensate and NGL pricing, as compared to the same period in 2007. The average daily and monthly AECO indices for natural gas during this quarter was 9% and 13%, respectively, higher than in the same period in 2007. For the three months ending December 31, 2008, True received an average natural gas price, before transportation and hedging, of \$6.98/Mcf, 9% higher than \$6.40/Mcf in the same period in 2007 and 22% lower than \$8.97/Mcf in the third quarter of 2008. For heavy crude oil, True received an average price before transportation of \$36.52/bbl during the fourth quarter of 2008, 8% less than \$39.72/bbl in the same period in 2007 and 61% less than \$92.51/bbl in the third quarter of 2008. In comparison, the average reference price for Hardisty Heavy crude in the fourth quarter of 2008 was 12% less than the average 2007 price in the same period. For light oil, condensate and NGLs, True received an average price of \$45.96/bbl before transportation and hedging during the last quarter of 2008, 41% less than the average price of \$78.42/bbl received in the same period of 2007, compared to a 27% decrease in the Edmonton par reference price. The average price for light oil, condensate and NGLs for True was 57% lower than the \$107.55/bbl for the third quarter of 2008. During the fourth quarter of 2008, revenue before other income and hedging of \$40.2 million was 33% lower than the corresponding 2007 period.

In the fourth quarter of 2008, the Trust paid \$9.0 million in royalties, compared to \$12.6 million in the same period in 2007. As a percentage of pre-hedge sales (after transportation costs), royalties were 23% in the fourth quarter of 2008 compared to 22% in the same period in 2007. In this same period of 2008, operating costs totaled \$17.9 million, compared to \$16.5 million recorded in the same period of 2007. During the fourth quarter of 2008, operating costs averaged \$18.11/boe, up from the \$12.01/boe incurred during the fourth quarter of 2007. The increase was due to a number of factors including incremental unanticipated prior period cost adjustments from non-operated properties and additional workover and other costs from earlier in 2008. Also, fuel gas costs associated with steam generation at the Kerrobert facility contributed \$1.57/boe in the fourth quarter of 2008, whereas these costs were capitalized in 2007 during initial steaming period for the project expansion. In addition, the fixed component of certain operating costs combined with reduced sales volumes between comparable periods has contributed to the increase in costs on a per boe basis. In comparison, operating costs for the third quarter of 2008 averaged \$14.95/boe. True is targeting operating costs of approximately \$48.8 million (\$13.40/boe) in 2009. This is based upon assumptions of estimated production of approximately 10,000 boe/d and planned cost reductions. During the fourth quarter of 2008, company field operating netbacks decreased by 40% to \$12.31/boe compared to 2007, driven primarily by decreased overall commodity prices and increased operating costs. In comparison, the company field operating netback for the third quarter of 2008 was \$38.31/boe. Field operating netbacks for natural gas before hedging during the fourth quarter of 2008 of \$2.35/Mcf were 15% less than the 2007 netbacks, reflecting higher royalties and production costs, somewhat offset by higher commodity prices and reduced transportation costs. In comparison, the field operating netback for

natural gas for the third quarter of 2008 was \$5.50/Mcf. Field operating netbacks before hedging for crude oil, condensate and NGLs during the fourth quarter of 2008 averaged \$9.68/bbl, down from \$27.34/bbl during the fourth quarter of 2007, primarily as a result of a significant decrease in the overall commodity price received, and with higher production expenses partially offset by a reduction in royalties. In comparison, the field operating netback for crude oil, condensate and NGLs for the third quarter of 2008 was \$48.07/bbl.

In the fourth quarter of 2008, the net cost of general and administrative expenses was \$4.1 million, compared to \$4.7 million in the comparable 2007 period reflecting a reduction of the number of salaried personnel on staff and other efforts to reduce costs. Fourth quarter 2008 general and administrative costs include \$1.0 million of charges associated with severance costs. True is forecasting general and administrative costs of approximately \$11.5 million (\$3.15/boe) in 2009 based on the cost reduction initiatives applied in early January and estimated 2009 production volumes of approximately 10,000 boe/d. This represents an approximate 30% reduction over 2008 costs.

Depletion, depreciation and accretion expense for the fourth quarter of 2008 was \$29.4 million, compared to \$39.8 million in 2007, which reflects reduced carrying costs in 2008, combined with lower production volumes in fourth quarter 2008 versus 2007.

2008 Annual Financial and Operational Results

Net Loss and Funds Flow from Operations

True generated funds flow from operations of \$77.9 million (\$0.98 per diluted unit) for the year ended December 31, 2008, down 23% from \$101.2 million (\$1.33 per diluted unit) for the 2007 year. The decrease in funds flow for the 2008 year compared to 2007 was primarily the result of lower sales volumes and higher realized hedging losses, despite improved commodity pricing and operating netbacks.

True maintains a commodity price risk management program to provide a measure of stability to funds flow from operations. Unrealized mark-to-market gains or losses are non-cash adjustments to the current fair market value of the contract over its entire term and are included in the calculation of net loss.

The net loss for the 2008 year was \$19.6 million (\$0.25 per diluted unit) compared to a net loss of \$24.3 million (\$0.32 per diluted unit) in 2007. The decrease in the net loss from 2007 to 2008 was primarily due to reduced non-cash charges for depletion, depreciation and accretion, higher unrealized gains on commodity contracts, offset by a reduced future income tax recovery and lower funds flow from operations.

Funds Flow From Operations and Net Loss

<i>(\$000s, except per unit amounts)</i>	Years Ended December 31,	
	2008	2007
Funds flow from operations	77,893	101,172
Basic (\$/unit)	0.99	1.33
Diluted (\$/unit)	0.98	1.33
Net loss	(19,590)	(24,267)
Basic (\$/unit)	(0.25)	(0.32)
Diluted (\$/unit)	(0.25)	(0.32)

Reconciliation of Funds Flow from Operations and Cash Flow from Operating Activities

<i>(\$000s, except per unit amounts)</i>	Years ended December 31,	
	2008	2007
Funds flow from operations	77,893	101,172
Asset retirement costs incurred	(2,603)	(835)
Change in non-cash working capital	3,494	(18,131)
Cash flow from operating activities	78,784	82,206

Sales Volumes

Sales volumes for the year ended December 31, 2008 averaged 11,867 boe/d compared to 16,139 boe/d for the same period in 2007, representing a 26% decrease.

In addition to natural production decline and minimal 2008 capital spending, year over year production volumes were impacted by dispositions totalling approximately 1,000 boe/d that were closed during the first half of 2008. Also, approximately 950 boe/d was affected in the fourth quarter of 2008 (approximately 240 boe/d annualized) due to extreme weather conditions causing delayed servicing and freeze offs.

On October 1, 2008, True closed the purchase of further working interests in the Mantario, Saskatchewan area for \$4.3 million in cash after adjustments. Effective October 1, 2008 this tuck-in acquisition adds approximately 225 bbls/d of heavy oil production for metrics of \$19,100/boe/d and \$8.60/boe.

Sales Volumes

		Years ended December 31,	
		2008	2007
Natural gas	(mcf/d)	45,202	64,853
Heavy oil	(bbls/d)	2,897	3,450
Light oil and condensate	(bbls/d)	999	1,289
NGLs	(bbls/d)	437	591
Total crude oil and NGLs	(bbls/d)	4,333	5,330
Total boe/d	(6:1)	11,867	16,139

During the 2008 year, True had an interest in a total of 38 wells (17.1 net) drilled, which resulted in 7.1 net natural gas wells, 4.0 net light oil wells, 0.8 net heavy oil well and 1.0 net water disposal well. 4.2 net were dry and abandoned.

Included in the above were nine gross natural gas wells that evaluated True land at no cost to the Company. In eight True has an overriding royalty; in the other True has no capital cost to drill, complete and tie in, retaining a 20% working interest from first production. True has over 377,000 net acres of undeveloped mineral leases in Alberta, British Columbia and Saskatchewan as of December 31, 2008. An integral component of our growth strategy is to aggressively farmout our interest in non core areas.

By comparison, True drilled or participated in 40 (27.3 net) working interest wells in 2007.

For the year ended December 31, 2008, the weighting towards natural gas sales averaged 63% compared to 67% for the 2007 year. Heavy oil sales made up 24% of total production for the 2008 year compared to 21% in 2007.

Sales of natural gas averaged 45.2 Mmcf/d for 2008, compared to 64.9 Mmcf/d in 2007, a decrease of 30%. Crude oil and NGL sales for 2008 decreased 19% averaging 4,333 bbls/d compared to 2007 average sales of 5,330 bbls/d.

2009 production volumes are anticipated to average approximately 10,000 boe/d. The forecast of 2009 production volumes is based upon a number of assumptions, including normal production declines and expenditures under the current planned capital budget of \$15 million.

Commodity Prices

Average Commodity Prices

	Years ended December 31,		
	2008	2007	% Change
Exchange rate (US\$/Cdn\$)	0.9372	0.9390	-%
Natural gas:			
NYMEX (US\$/mmbtu)	8.89	7.14	25%
AECO daily index (CDN\$/Mcf)	8.13	6.44	26%
AECO monthly index (CDN\$/Mcf)	8.12	6.61	23%
True's average price (\$/mcf)	8.50	6.73	26%
True's average price (including hedging ⁽¹⁾) (\$/mcf)	8.00	7.08	13%
Crude oil:			
WTI (US\$/bbl)	99.73	74.25	34%
Edmonton par – light oil (\$/bbl)	102.85	77.06	33%
Bow River – medium/heavy oil (\$/bbl)	83.85	53.16	58%
Hardisty Heavy – heavy oil (\$/bbl)	76.32	44.77	70%
True's average prices (\$/bbl)			
Light crude oil, condensate, and NGLs	88.42	64.60	37%
Heavy crude oil	70.96	40.05	77%
Total crude oil and NGLs	76.75	48.71	58%
Total crude oil and NGLs (including hedging ⁽¹⁾)	64.24	47.74	35%

⁽¹⁾Per unit metrics including hedging include realized gains or losses on commodity contracts and exclude unrealized gains or losses on commodity contracts.

True's natural gas sales are priced with reference to the daily or monthly AECO indices. During 2008, the AECO daily and monthly reference price increased by 26% and 23%, respectively, compared to the same period in 2007. Similarly, True's average sales price before hedging for 2008 increased by 26% compared to the same period in 2007. True's natural gas price after including hedging for 2008 was \$8.00/mcf compared to \$7.08/mcf for 2007.

The Trust has entered into a natural gas physical delivery sales contract to sell 5,275 GJ/day at a fixed price of \$7.29/GJ and \$7.90/GJ for the third and fourth quarter of 2009, respectively.

For heavy crude oil, True received an average price before transportation of \$70.96/bbl for 2008, an increase of 77% over prices in the 2007 year. The Bow River reference price increased by 58% and the Hardisty Heavy reference price increased by 70% over the same period. The majority of True's heavy crude oil density ranges between 11 and 16 degrees API consistent with the Hardisty Heavy reference price, although all of True's heavy oil production is sold at Saskatchewan delivery points. During 2008, the blending costs for condensate were lower which has also contributed to higher pricing received

For light oil, condensate and NGLs, True recorded an average \$88.42/bbl before hedging during 2008, 37% higher than the average price received in the 2007 year. In comparison, the Edmonton par price increased by 33% over the same period. The average WTI crude oil US dollar based price increased 34% from 2007 to 2008. True's realized price after including hedging was \$126.14/bbl for 2008 compared to \$45.22/bbl for the same period in 2007. Although oil prices achieved record highs throughout 2008, peaking in July at US\$147.27 per barrel of for WTI and averaging US\$99.73 per barrel for the full year, the sharp decline in oil prices during the fourth of 2008 has resulted in exit 2008 oil prices at their lowest level since 2004. The full impact of the price decline will not be realized until the first quarter of 2009. The average US\$/Cdn\$ foreign exchange rate was 0.94 for the full year of 2008; however, a sharp decline in the fourth quarter resulted in the U.S. dollar closing at 0.83 per Canadian dollar on December 31, 2008. The negative correlation between the Canadian dollar and U.S. dollar denominated WTI oil prices should

lessen the impact on the Trust of any future declines in the price of oil, however, crude oil prices have remained depressed in the early part of 2009 and investors should expect that revenues in 2009 will be significantly lower than those recorded in 2008.

WTI crude oil prices varied greatly throughout 2008, increasing significantly to a high of US\$147/bbl in July and dramatically falling during the fourth quarter of 2008 with December 2008 prices of under US\$40/bbl. The pricing outlook in 2009 for crude oil and natural gas remains uncertain given the current global economic environment.

Revenue

Revenue before other income and hedging for the year ended December 31, 2008 was \$262.4 million, 3% higher than the \$254.0 million in the same period in 2007. The higher revenue for the 2008 period was the result of significantly higher commodity prices, despite lower sales volumes.

(\$000s)	Years ended December 31,	
	2008	2007
Light crude oil, condensate and NGLs	46,485	44,325
Heavy oil	75,241	50,436
Crude oil and NGLs	121,726	94,761
Natural gas	140,701	159,278
Total revenue before other	262,427	254,039
Other ⁽¹⁾	2,958	4,451
Total revenue before royalties and hedging	265,385	258,490

⁽¹⁾ Other revenue primarily consists of processing and other third party income.

Revenues for 2009 are currently expected to be lower than 2008 due to lower commodity prices and average estimated 2009 production of approximately 10,000 boe/d.

Commodity Price Risk Management

The Trust has a formal risk management policy which permits management to use specified price risk management strategies for up to 50% of crude oil, natural gas and NGL production including fixed price contracts, collars and the purchase of floor price options and other derivative financial instruments and physical delivery sales contracts to reduce the impact of price volatility and ensure minimum prices for a maximum of eighteen months beyond the current date. The program is designed to provide price protection on a portion of the Trust's future production in the event of adverse commodity price movement, while retaining significant exposure to upside price movements. By doing this, the Trust seeks to provide a measure of stability to funds flow from operations, as well as, to ensure True realizes positive economic returns from its capital developments and acquisition activities. The Trust will continue its hedging strategies focusing on maintaining sufficient cash flow to fund True's operations. Any remaining unhedged production is realized at market prices.

A summary of the financial hedge volumes and average prices by quarter currently outstanding as of March 16, 2009 is shown in the following tables:

Natural gas

Average Volumes (GJ/d)

	Q1 2009	Q2 2009	Q3 2009	Q4 2009
Fixed	15,544	20,050	19,500	15,000
	Q1 2010	Q2 2010	Q3 2010	Q4 2010
Fixed	10,000	5,000	-	-
Call option (ceiling price)	5,000	5,000	5,000	5,000
Total GJ/d	15,000	10,000	5,000	5,000

Average Price (\$/GJ AECO C)

	Q1 2009	Q2 2009	Q3 2009	Q4 2009
Fixed	6.94	6.01	5.97	6.75

	Q1 2010	Q2 2010	Q3 2010	Q4 2010
Fixed	7.58	6.59	-	-
Call option (ceiling price)	8.05	8.05	8.05	8.05

Crude oil and liquids**Average Volumes (bbls/d)**

	Q1 2009	Q2 2009	Q3 2009	Q4 2009
Costless collars	172	500	500	500
Total bbls/d	172	500	500	500

Average Price (US\$/bbl WTI)

	Q1 2009	Q2 2009	Q3 2009	Q4 2009
Collar ceiling price	65.60	65.60	65.60	65.60
Collar floor price	42.50	42.50	42.50	42.50

Included in the above natural gas table is a fixed price contract of \$5.90/GJ at 5,000 GJ/d for the Q2 2009 to Q4 2009 periods which was funded by selling a call option of 5,000 GJ/d at \$8.05 for the 2010 year.

As of December 31, 2008, the fair value of True's outstanding commodity contracts is an unrealized asset of \$3.7 million as reflected in the financial statements. The fair value or mark-to-market value of these contracts is based on the estimated amount that would have been received or paid to settle the contracts as at December 31, 2008 and may be different from what will eventually be realized. Changes in the fair value of the commodity contracts are recognized in the Consolidated Statements of Loss within the financial statements.

Strong commodity prices throughout most of 2008 had a significant impact on the Trust's revenue; however, these strong prices resulted in realized cash losses of \$19.8 million and \$8.4 million for the Trust's oil and natural gas risk management contracts, respectively.

The following is a summary of the gain (loss) on commodity contracts for the years ended December 31, 2008 and 2007 as reflected in the Consolidated Statements of Loss in the financial statements:

Commodity contracts

(\$000s)	Crude Oil & Liquids	Natural Gas	2008 Total
Realized cash loss on contracts	(19,835)	(8,387)	(28,222)
Unrealized gain on contracts ⁽²⁾	11,404	2,664	14,068
Total loss on commodity contracts	(8,431)	(5,723)	(14,154)

(\$000s)	Crude Oil & Liquids	Natural Gas	2007 Total
Realized cash gain (loss) on contracts ⁽¹⁾	(1,891)	8,382	6,491
Unrealized gain (loss) on contracts ⁽²⁾	(11,404)	1,061	(10,343)
Total gain (loss) on commodity contracts	(13,295)	9,443	(3,852)

⁽¹⁾ Includes the crude oil and natural gas commodity contract premium expenses and the amortization of prior year crude oil and natural gas commodity contract premiums of a total \$3.7 million for the year ended December 31, 2007.

⁽²⁾ Unrealized gain (loss) commodity contracts represent non-cash adjustments for changes in the fair value of these contracts during the period.

Royalties

For the year ended December 31, 2008, total royalties were \$54.6 million, compared to \$47.0 million incurred in 2007. Overall royalties as a percentage of revenue (after transportation costs) in 2008 were 21%, compared with 19% in 2007. Royalties were lower by approximately \$5.5 million in 2007 due to the reversal of certain prior period over accruals for light and heavy crude oil royalties; excluding these adjustments, the average royalty rate for the year ended December 31, 2007 would have been 20%.

Royalties by Commodity Type (\$000s, except where noted)	Years ended December 31,	
	2008	2007
Light crude oil, condensate and NGLs	11,211	9,772
\$/bbl	21.33	14.24
Average light crude oil, condensate and NGLs royalty rate (%)	25	22
Heavy Oil	14,060	6,867
\$/bbl	13.26	5.45
Average heavy oil royalty rate (%)	20	14
Natural Gas	29,291	30,365
\$/mcf	1.77	1.28
Average natural gas royalty rate (%)	21	20
Total	54,562	47,004
\$/boe	12.56	7.98
Average total royalty rate (%)	21	19

Royalties, by Type

(\$000s)	Years ended December 31,	
	2008	2007
Crown royalties	30,354	20,799
Indian Oil and Gas Canada royalties	6,479	5,927
Freehold & GORR	17,729	20,278
Total	54,562	47,004

Expenses

(\$000s)	Years ended December 31,	
	2008	2007
Production	66,573	68,282
Transportation	7,047	7,938
General and administrative	15,958	18,186
Interest and financing charges	14,822	18,108
Unit-based compensation	1,395	2,001

Expenses per boe

(\$ per boe)	Years ended December 31,	
	2008	2007
Production	15.33	11.59
Transportation	1.62	1.35
General and administrative	3.67	3.09
Interest and financing charges	3.41	3.07
Unit-based compensation	0.32	0.34

Production Expenses

For the year ended December 31, 2008, production expenses totaled \$66.6 million (\$15.33/boe), compared to \$68.3 million (\$11.59/boe) recorded in 2007. The increase in production expenses in 2008 on a boe basis is due to a number of factors. Repairs and operating workovers for 2008 were approximately \$15.6 million (\$3.59/boe)

compared to \$19.1 million (\$3.24/boe) in 2007. Also, fuel gas costs associated with steam generation at the Kerrobert facility contributed \$1.91/boe in 2008, whereas these costs were capitalized in late 2007 during initial steaming period for the project expansion. In addition, the fixed component of certain production expenses combined with reduced sales volumes between comparable periods has contributed to the increase in costs on a per boe basis. True is targeting operating costs of approximately \$48.8 million (\$13.40/boe) in 2009. This is based upon assumptions of estimated production of approximately 10,000 boe/d and planned cost reductions.

Production Expenses, by Commodity Type

(\$000s, except where noted)	Years ended December 31,	
	2008	2007
Light crude oil, condensate and NGLs \$/bbl	10,155 19.32	9,906 14.44
Heavy oil \$/bbl	22,672 21.38	18,301 14.53
Natural gas \$/mcf	33,746 2.04	40,075 1.69
Total \$/boe	66,573 15.33	68,282 11.59
Total	66,573	68,282
Processing and other third party income ⁽¹⁾	(2,958)	(4,451)
Total after deducting processing and other third party income \$/boe	63,615 14.65	63,831 10.84

(1) Processing and other third party income is included within petroleum and natural gas sales on the statement of income.

Transportation

Transportation expenses have historically been approximately 2% to 3% of gross revenues. For the years ended December 31, 2008 and 2007, transportation expenses averaged approximately 3%.

Operating Netback

For the 2008 year, corporate field operating netback (before hedging) was \$30.91/boe compared to \$22.21/boe in fiscal 2007. This was the result of increased overall commodity prices, partially offset by higher transportation, royalties and operating costs experienced in 2008. After including hedging activities, the corporate field operating netback for 2008 was \$24.41/boe compared to \$23.31/boe in 2007.

Field Operating Netback – Corporate (before hedging)

(\$/boe)	For the years ended December 31,	
	2008	2007
Sales	60.42	43.13
Transportation	(1.62)	(1.35)
Royalties	(12.56)	(7.98)
Production expense	(15.33)	(11.59)
Field operating netback	30.91	22.21

Overall, corporate operating netbacks for 2009 are currently expected to be lower than 2008 due to anticipated lower commodity prices.

Field operating netback for natural gas in 2008 increased 30% to \$4.52/mcf, compared to \$3.47/mcf in 2007, reflecting stronger natural gas prices experienced, the effects of which were partially offset by higher royalties and transportation expenses. After including hedging activities, field operating netback for natural gas for fiscal 2008 was \$4.02/mcf compared to \$3.83/mcf in the same period in 2007.

Field Operating Netback – Natural Gas (before hedging)

(\$/mcf)	Years ended December 31,	
	2008	2007
Sales	8.50	6.73
Transportation	(0.17)	(0.29)
Royalties	(1.77)	(1.28)
Production expense	(2.04)	(1.69)
Field operating netback	4.52	3.47

Field operating netback for crude oil, condensate and NGLs averaged \$37.46/bbl for 2008, up 50% compared to \$25.01/bbl for 2007. This compares to a 58% increase in the crude oil, condensate and NGLs sales price combined with an increase in overall expenses over the same period. After including hedging activities, field operating netback for crude oil and NGLs for 2008 was \$24.96/boe compared to \$24.04/boe in 2007.

Field Operating Netback – Crude Oil, Condensate and NGLs (before hedging)

(\$/bbl)	Years ended December 31,	
	2008	2007
Sales	76.75	48.71
Transportation	(2.66)	(0.65)
Royalties	(15.93)	(8.55)
Production expense	(20.70)	(14.50)
Field operating netback	37.46	25.01

General and Administrative

Net general and administrative (“G&A”) expenses for 2008 were \$16.0 million compared to \$18.2 million for 2007. The decrease in the G&A expense for the year ended December 31, 2008 from the same period in 2007 reflects a reduction of the number of salaried personnel on staff and other efforts to reduce costs. G&A costs for the year includes \$1.0 million of charges associated with severance costs in the fourth quarter of 2008. The reduction in amounts of capitalized G&A for 2008 is consistent with a lower capital program. On a per boe basis, G&A expenses for fiscal 2008 were \$3.67/boe compared to \$3.09/boe for fiscal 2007. The increase in G&A on a per boe basis is consistent with reduced sales volumes experienced in 2008 compared to 2007.

True had targeted reductions in G&A expenses in early 2009. As part of the G&A cost reductions, True has streamlined its operations and reduced head office staffing levels and costs by approximately one third. For 2009, the Trust is anticipating G&A costs to be approximately \$11.5 million (\$3.15/boe) based on the cost reduction initiatives applied in early January 2009 and estimated 2009 production volumes of approximately 10,000 boe/d.

General and Administrative Expenses

(\$000s, except where noted)	Years ended December 31,	
	2008	2007
Gross expenses	20,197	24,191
Capitalized	(2,419)	(3,881)
Recoveries	(1,820)	(2,124)
Net expenses	15,958	18,186
Net expenses, per unit (\$/boe)	3.67	3.09

Interest and Financing Charges

True recorded \$14.8 million of interest and financing charges for the year ended December 31, 2008 compared to \$18.1 million in 2007. True's total net debt at December 31, 2008 of \$215.0 million includes the \$81.1 million liability portion of convertible debentures, \$132.4 million of bank debt and the net balance of working capital. The convertible debentures have a maturity date of June 30, 2011.

Interest and Financing Charges

(\$000s, except where noted)	Years ended December 31,	
	2008	2007
Interest and financing charges	14,822	18,108
Interest and financing charges (\$/boe)	3.41	3.07
Debt to funds flow from operations ratio annualized		
Total net debt ⁽¹⁾ at year end	215,004	250,313
Total net debt to periods funds flow from operations ratio annualized ⁽²⁾	9.2x	3.2x
Net debt ⁽¹⁾ (excluding convertible debentures) at year end	133,880	171,006
Net debt to periods funds flow from operations ratio annualized ⁽²⁾	5.7x	2.2x
Debt to funds flow from operations ratio		
Total net debt ⁽¹⁾ at year end	215,004	250,313
Total net debt to funds flow from operations ratio	2.8x	2.5x
Net debt ⁽¹⁾ (excluding convertible debentures) at year end	133,880	171,006
Net debt to funds flow from operations ratio	1.7x	1.7x

⁽¹⁾ Net debt includes the net working capital deficiency (excess) before short-term commodity contract assets and liabilities and short-term future tax assets and liabilities. Total net debt also includes the liability component of convertible debentures and excludes asset retirement obligations and the future income tax liability.

⁽²⁾ Debt to funds flow from operations ratio annualized is calculated based upon fourth quarter funds flow from operations annualized.

Unit-Based Compensation

Non-cash unit-based compensation expense for the year ended December 31, 2008 was \$1.4 million compared to \$2.0 million in 2007. The 2008 expense reflects a reduction in the estimated weighted average fair value of incentive rights granted for more recent options and a reduction to the 2008 expense of \$0.5 million for a reversal of prior year unit-based compensation expense for 2008 forfeitures of unvested incentive rights and reduced incentive rights being granted in 2008 compared to the 2007 period, offset by \$0.5 million of additional compensation expense for the incentive units voluntarily surrendered and cancelled in the year.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion expense for 2008 was \$128.9 million (\$29.68/boe), compared to the \$171.5 million (\$29.11/boe) in 2007, which reflects lower production volumes combined with reduced carrying costs in the 2008 period as compared to 2007.

For the year ended December 31, 2008, True has included \$62.8 million for future development costs in the depletion calculation and excluded from the depletion calculation \$31.3 million for undeveloped land and \$42.5 million for estimated salvage.

Depletion, Depreciation and Accretion Costs

(\$000s, except where noted)	Years ended December 31,	
	2008	2007
Depletion and Depreciation	126,773	169,347
Accretion	2,159	2,137
Total	128,932	171,484
Per unit (\$/boe)	29.68	29.11

Special Meeting Costs

On January 15, 2007, the Trust announced its proposal to convert into an intermediate exploration and production company (the "Reorganization"). Pursuant to the Reorganization, it was contemplated that holders of Trust units of the Trust would receive an equal number of common shares of a newly formed corporation that would hold the assets previously held directly or indirectly by the Trust. The exchangeable shares were also to be exchanged for common shares based on the conversion ratio thereof. The Reorganization was subject to all required regulatory approvals and securityholder approval by at least 66 2/3% of the votes cast by unitholders of the Trust and holders of the exchangeable shares. At the Special and Annual Meeting held on March 30, 2007, the special resolution related to the Reorganization was not approved. As a result, the Reorganization was not completed.

The Trust incurred \$3.8 million in costs for legal, financial advisory, accounting, unitholder solicitation services, printing, mailing and other expenses that are included as special meeting costs within the statement of income for the year ended December 31, 2007.

Capital Expenditures

True invested \$36.7 million on exploration and development activities during 2008, compared to \$87.3 million in 2007.

During the 2008 year, True had an interest in a total of 38 wells (17.1 net) drilled, which resulted in 7.1 net natural gas wells, 4.0 net light oil wells, 0.8 net heavy oil well and 1.0 net water disposal well. 4.2 net were dry and abandoned.

Included in the above were nine gross natural gas wells that evaluated True land at no cost to the Company. In eight True has an overriding royalty; in the other True has no capital cost to drill, complete and tie in, retaining a 20% working interest from first production. True has over 377,000 net acres of undeveloped mineral leases in Alberta, British Columbia and Saskatchewan as of December 31, 2008. An integral component of our growth strategy is to aggressively farmout our interest in non core areas.

Capital Expenditures

(\$000s)	Years ended December 31,	
	2008	2007
Lease acquisitions and retention	1,244	2,084
Geological and geophysical	318	4,275
Drilling and completion costs	19,008	64,638
Facilities and equipment	16,129	15,294
Other Capital ⁽²⁾	-	1,056
Exploration and development ⁽¹⁾	36,699	87,347
Corporate and property acquisitions	6,303	1,505
Total capital expenditures – cash	43,002	88,852
Property dispositions – cash	(44,340)	(31,808)
Total net capital expenditures – cash	(1,338)	57,044
Other – non-cash ⁽³⁾	3,710	(530)
Total net capital expenditures ⁽¹⁾	2,372	56,514

(1) Excludes capitalized costs related to asset retirement obligation expenditures incurred during the year.

(2) Other capital for 2007 includes natural gas input costs incurred during the initial "warm-up" phase at the Kerrobert SAGD expansion project.

(3) Other includes non-cash adjustments for current period's asset retirement obligations and unit based compensation capitalized. For 2007, it also includes a \$(0.8 million) initial fair value adjustment for marketable securities acquired.

The \$43.0 million capital program for the year ended December 31, 2008, was financed entirely with funds flow from operations.

During the first quarter of 2008, True was successful in completing the divestiture of a non-core property in Northeast Alberta for net proceeds of \$5.8 million. During the second quarter of 2008, True disposed of its Dodsland-Stranraer property located in Saskatchewan for net proceeds of \$38.5 million. Total net proceeds from the sale of properties in the 2008 were \$44.3 million; the net proceeds from the dispositions were used to pay down debt.

On October 1, 2008 True closed the purchase of further working interests in the Mantario, Saskatchewan area for \$4.3 million in cash after adjustments.

Based on the current economic conditions and True's operating forecast for 2009, the Trust budgets a capital program of \$15 million.

True holds an extensive land base. At December 31, 2008, True had approximately 377,763 net undeveloped acres of land of its total developed and undeveloped net acreage position of 677,216 net acres in Saskatchewan, Alberta, and British Columbia.

Ceiling Test

The Trust calculates a ceiling test quarterly and annually to place a limit on the aggregate carrying value of its capitalized costs, which may be amortized against revenues of future periods. The ceiling test is performed in accordance with the requirements of the Canadian Institute of Chartered Accountants ("CICA") AcG-16 "Oil and Gas Accounting – Full Cost", a two step process.

The Trust performed a ceiling test calculation at December 31, 2008 resulting in undiscounted cash flows from proved reserves and the undeveloped properties not exceeding the carrying value of oil and gas assets. Consequently, True performed stage two of the ceiling test assessing whether discounted future cash flows from the production of proved plus probable reserves plus the carrying cost of undeveloped properties, net of any impairment allowance, exceeds the carrying value of its petroleum and natural gas properties. No impairment in oil and gas assets was identified as at December 31, 2008.

The ceiling test calculation will be updated in 2009 on a quarterly and annual basis based upon the latest available data, including but not limited to an updated annual external reserve engineering report which incorporates a full evaluation of reserves or internal reserve updates at quarterly periods, and the latest commodity pricing deck. Estimating reserves is very complex, requiring many judgments based on available geological, geophysical, engineering and economic data. Changes in these judgments could have a material impact on the estimated reserves. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available and as the economic environment changes.

Asset Retirement Obligations

As at December 31, 2008, the Trust has recorded an Asset Retirement Obligation ("ARO") of \$33.7 million, compared to \$28.4 million at December 31, 2007, for future abandonment and reclamation of the Trust's properties. For the year ended December 31, 2008, the ARO increased by \$5.3 million total as a result of liabilities incurred through corporate acquisitions of \$0.3 million, accretion expense of \$2.2 million, and \$8.7 million net changes in estimates and liabilities incurred on development activities, offset by \$3.3 million of liabilities released on dispositions and \$2.6 million of liabilities settled during the year.

Income Taxes

For the year ended December 31, 2008, the Trust has recorded capital tax expense of \$2.0 million compared to \$2.0 million expensed in 2007. Capital taxes are based on debt and equity levels of the Trust at the end of the year in addition to a resource surcharge component of Saskatchewan provincial taxes calculated as a percentage of revenues.

Future income taxes arise from differences between the accounting and tax bases of the Trust's assets and liabilities. For the year ended December 31, 2008, the Trust recognized a future income tax recovery of \$20.4 million compared to a recovery of \$59.8 million in 2007.

Under our current structure, the operating entities make interest and royalty payments to the Trust, which transfers taxable income to the Trust to eliminate income subject to corporate and other income taxes in the operating entities.

Under the SIFT legislation (as referred to below), such amounts transferred to the Trust could be taxable beginning in 2011 as distributions will no longer be deductible for income tax purposes. At that time, True could claim discretionary tax deductions in its operating companies, reduce the income transferred to the Trust, and pay all or a portion of distributions as a return of capital. Until 2011, under the terms of its trust indenture, the Trust is required to distribute amounts at least equal to its taxable income. In the event that the Trust has undistributed taxable income in a taxation year (prior to 2011), an additional special taxable distribution, subject to certain withholding taxes for non-resident holders, would be required under the trust indenture.

The SIFT legislation is not expected to directly affect our cash flow levels and distribution policies until 2011 at the earliest.

Enactment of the Tax on Income Trusts

On June 22, 2007, the legislation implementing a new tax (the "SIFT tax") on publicly traded income trusts and limited partnerships, referred to as "Specified investment flow-through" ("SIFTs") entities (Bill C-52) received Royal Assent. As a result, the SIFT tax was considered to be enacted for accounting purposes in June 2007, which resulted in a \$1.2 million future income tax recovery amount being recorded in 2007 to reflect current temporary differences between the book and tax basis of assets and liabilities expected to be remaining in the Trust in 2011. The SIFT tax announcement and the related future income tax recovery did not affect cash flow or distributions and is not expected to affect distribution policies until 2011 at the earliest.

SIFTs are certain publicly traded income and royalty trusts and limited partnerships including True. For SIFTs in existence on October 31, 2006 the SIFT tax will be effective in 2011, unless certain rules related to "undue expansion" are not adhered to. Under the guidance provided, True can increase its equity by approximately \$737 million between 2006 and 2011 without prematurely triggering the SIFT tax.

In June 2008, Bill C-50, which contained legislation to adjust the deemed provincial component of the tax rate on distributions from income and royalty trusts expected to apply to the Trust commencing in 2011, received Royal Assent. Under proposed regulations, instead of basing the provincial component of the SIFT tax on a flat rate of 13%, the provincial component will instead be based on the general provincial corporate income tax rate in each province in which the SIFT has a permanent establishment. For purposes of calculating this component of the tax, the general corporate taxable income allocation formula will be used. Specifically, the Trust's taxable distributions will be allocated to two provinces by taking half of the aggregate of:

- that proportion of the Trust's taxable distributions for the year that the Trust's wages and salaries in the province are of its total wages and salaries in Canada; and
- that proportion of the Trust's taxable distributions for the year that the Trust's gross revenues in the province are of its total gross revenues in Canada.

Under the proposed regulations, the Trust would be considered to have a permanent establishment only in Alberta, where the provincial tax rate in 2011 is expected to be 10%. As the regulations were not substantively enacted for accounting purposes as at December 31, 2008, the 13% flat rate is used for financial statement purposes.

On July 14, 2008, the Department of Finance released proposed amendments (the "Conversion Rules") to the Income Tax Act (Canada) to facilitate the conversion of existing income trusts into corporations. In general, the proposed amendments will permit a conversion to be tax deferred for both the unitholders and the income trust if completed before 2013. These rules were subsequently revised and introduced as part of Bill C-10 as part of the Budget Implementation Act, 2009 on February 6, 2009. Further revisions are expected as it is debated in the House of Commons.

The True Board of Directors and Management continue to review the impact of this tax on business strategy as well as the Conversion Rules in considering alternatives available. At the present time, True believes some or all of the following actions will or could result due to the enactment of the SIFT tax:

- If structural or other similar changes are not made, the distribution yield net of the SIFT tax in 2011 and beyond to taxable Canadian investors will remain approximately the same; however, the distribution yield to tax-deferred Canadian investors (RRSPs, RRIFs, pension plans, etc.) would fall by an estimated 26.5 percent in 2011 and 25.0 percent in 2012 and beyond. For U.S. investors, the distribution yield net of the SIFT and withholding taxes would fall by an estimated 25.3 percent in 2011 and 25.1 percent in 2012 and beyond;
- A portion of True's cash flow could be allocated to the payment of the SIFT tax, or other forms of tax, and would not be available for distribution or re-investment;
- True could convert to a corporate structure to facilitate investing a higher proportion or all of its cash flow in exploration and development projects. Such a conversion and change to capital programs could result in a significant reduction to or elimination of distributions and/or dividends;
- True might determine that it is more economic to remain in the trust structure, at least for a period of time, and shelter its taxable income using discretionary tax deductions and pay all or a portion of its distributions (if any) on a return of capital basis, likely at a lower payout ratio.

The Trust is reviewing all organizational structures and alternatives to minimize the impact of the SIFT tax on our unitholders. While there can be no assurance that the negative effect of the tax can be minimized or eliminated, True and its advisors will continue to work diligently on these issues.

As at December 31, 2008, the operating subsidiaries and the Trust itself have a total net future income tax liability balance of \$43.9 million. Canadian GAAP requires that a future income tax liability be recorded when the book value of assets exceeds the balance of tax pools.

At December 31, 2008, the Trust and operating subsidiaries of the Trust had approximately \$495 million in tax pools available for deduction against future income as follows:

(\$000s)	Trust	Operating subsidiaries	Total
Intangible resource pools	15,000	306,000	321,000
Undepreciated capital cost	-	128,000	128,000
Loss carryforwards (expire through 2027)	-	40,000	40,000
Unit issue costs	4,000	2,000	6,000
	19,000	476,000	495,000

Distributions

Trust unitholders who held their trust units throughout 2008 received distributions of \$0.46 per unit. For the year ended December 31, 2008 the Trust declared distributions as follows:

(\$000s, except per unit amount)	Distribution Per Unit	Total
Year ended December 31, 2008		
Distributions declared	\$ 0.46	\$ 36,334

Distribution Paid History ⁽¹⁾

Distributions comprise a taxable portion and a return of capital portion (tax deferred). The return of capital component reduces the cost basis of the trust units held, as described below. For additional information, please see our website at www.trueenergytrust.com.

Calendar Year	Distributions per unit	Taxable Portion	Return of Capital
2005 (two months) ⁽²⁾	\$ 0.480	\$ 0.456	\$ 0.024
2006	\$ 2.640	\$ 2.033	\$ 0.607
Cumulative to Dec. 31, 2006	\$ 3.120	\$ 2.489	\$ 0.631
2007 year	\$ 0.960	\$ 0.960	-
Cumulative to Dec. 31, 2007	\$ 4.080	\$ 3.449	\$ 0.631
2008 year	\$ 0.460	\$ 0.460	-
Cumulative to December 31, 2008 ⁽³⁾	\$ 4.540	\$ 3.909	\$ 0.631
2009 year to date (one month) ⁽⁴⁾	\$ 0.020		
Cumulative to January 31, 2009	\$ 4.560		

⁽¹⁾ Applies to unitholders who are residents of Canada and hold their trust units as capital property.

⁽²⁾ Based upon the distributions paid in the 2005 calendar year, after the November 2, 2005 Arrangement with TKE Energy Trust.

⁽³⁾ For Canadian tax purposes, 2008 distributions were determined to be 100% taxable.

In consultation with its U.S. tax advisors, True believes that its Trust units should be "qualified dividends" for U.S. federal purposes. As such, the portion of distributions made during 2008 that are considered dividends for U.S. federal purposes should qualify for the reduced rate of tax applicable to long-term capital gains. Unitholders or potential unitholders should consult their own legal or tax advisors as to their particular income tax consequences of holding True units. Please review our February 19, 2009 press release addressing this.

⁽⁴⁾ It is currently estimated that the approximate taxable portion of the January 2009 distribution to Canadian unitholders will be 100%. Any non-taxable amounts will be treated as a tax deferred return of capital, or an adjustment to the cost base of the units. Actual taxable amounts may vary depending on actual distributions and are dependent upon production, commodity prices and funds flow from operations experienced throughout the year.

Monthly Distributions

Actual distributions paid and declared per Trust unit along with relevant payment dates for 2008 and 2009 to date are as follows:

Ex-distribution Date	Record Date	Payment Date	Distribution per unit
December 27, 2007	December 31, 2007	January 15, 2008	\$ 0.08
January 29, 2008	January 31, 2008	February 15, 2008	0.04
February 27, 2008	February 29, 2008	March 17, 2008	0.04
March 27, 2008	March 31, 2008	April 15, 2008	0.04
April 28, 2008	April 30, 2008	May 15, 2008	0.04
May 28, 2008	May 30, 2008	June 16, 2008	0.04
June 26, 2008	June 30, 2008	July 15, 2008	0.04
July 29, 2008	July 31, 2008	August 15, 2008	0.04
August 27, 2008	August 29, 2008	September 15, 2008	0.04
September 26, 2008	September 30, 2008	October 15, 2008	0.04
October 29, 2008	October 31, 2008	November 17, 2008	0.04
November 26, 2008	November 28, 2008	December 15, 2008	0.04
December 29, 2008	December 31, 2008	January 15, 2009	0.02
January 28, 2009	January 30, 2009	February 17, 2009	0.02

During 2008, funding requirements for distributions declared was 47% of funds flow from operations.

As announced on February 9, 2009, due to the continued deterioration in economic conditions, including the significant decline in crude oil prices, a weakening outlook for natural gas demand and heightened risk in the credit markets at the start of 2009, True has deemed it prudent to suspend March 2009 distributions to maintain corporate

liquidity during the current financial turmoil and prevailing commodity price environment. Accordingly, no distributions will be paid in March 2009 to unitholders of record as at February 27, 2009.

Distributions are to be reviewed monthly in the context of commodity prices, among other factors, and are subject to revision by the Board of Directors.

Foreign Ownership Update

Based on information from Trust records and information provided by intermediaries holding Trust units for others, the Trust estimates that, as of February 20, 2009 approximately 25 percent of unitholders are non-Canadian residents with the remaining 75 percent being Canadian residents.

In order that the Trust maintain its status as a "mutual fund trust" under the Income Tax Act (Canada), certain provisions of the Income Tax Act (Canada) require that the trust not be established or maintained primarily for the benefit of non-residents of Canada ("non-residents"). The trust indenture for the Trust provides that if the Trust or its administrator becomes aware that the activities of the Trust and ownership of Trust units by non-residents may threaten the status of the Trust under the Income Tax Act (Canada) as a "unit trust" or "mutual fund trust", the Trust is authorized to take action as may be necessary to maintain the status of the Trust as a unit trust and a mutual fund trust, including the imposition or restrictions on the issuance by the Trust, or the transfer of any unitholder, of Trust units to a non-resident.

Liquidity and Capital Resources

As an oil and gas business, the Trust has a declining asset base and therefore relies on ongoing development and acquisitions to replace production and add additional reserves. Future oil and natural gas production and reserves are highly dependent on the success of exploiting the Trust's existing asset base and in acquiring additional reserves. To the extent the Trust is successful or unsuccessful in these activities, funds flow could be increased or reduced.

Global financial markets have recently experienced severe turmoil. This economic crisis has spread resulting in a tightening of credit markets characterized by a decline in liquidity and higher borrowing costs. Access to capital markets has become constrained and significantly more expensive for the Trust along with other oil and gas entities. The current global economic environment has also created volatility in commodity prices, tempered somewhat by the growing US to Canadian dollar exchange rate. Given the current uncertain economic conditions, the Trust revised the level of capital spending for 2009 and suspended its March 2009 distribution. The Trust plans to continue to monitor forecasted debt levels to manage its operations within forecasted cash flow. In addition, the Trust will continue to monitor developments within the global economic environment to consider the impacts on current or future lending arrangements.

Liquidity risk is the risk that the Trust will not be able to meet its financial obligations as they fall due. The Trust actively manages its liquidity through daily and longer-term cash, debt and equity management strategies. Such strategies encompass, among other factors: having adequate sources of financing available through its bank credit facilities, estimating future cash generated from operations based on reasonable production and pricing assumptions, analysis of economic hedging opportunities, and maintaining sufficient cash flows for compliance with debt covenants.

The Trust generally relies on operating cash flows and its credit facilities to fund capital requirements and provide liquidity. Future liquidity depends primarily on cash flow generated from operations, existing credit facilities and the ability to access debt and equity markets. From time to time, the Trust accesses capital markets to meet its additional financing needs and to maintain flexibility in funding its capital programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Trust. The inability of the Trust to access sufficient capital for its operations could have a material adverse effect on the Trust's business financial condition, results of operations and prospects.

Credit risk is the risk of financial loss to the Trust if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Trust's trade receivables from joint venture partners, petroleum and natural gas marketers, and financial derivative counterparties.

A substantial portion of the Trust's accounts receivable are with customers and joint interest partners in the petroleum and natural gas industry and are subject to normal industry credit risks. The Trust sells substantially all of its production to eight primary purchasers under standard industry sale and payment terms. Purchasers of the Trust's natural gas, crude oil and natural gas liquids are subject to a periodic internal credit review to minimize the risk of non-payment. The Trust has continued to closely monitor and reassess the creditworthiness of its counterparties, including financial institutions. This has resulted in the Trust reducing or mitigating its exposures to certain counterparties where it is deemed warranted and permitted under contractual terms.

The Trust may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Trust, such failures may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Trust's ongoing capital program, potentially delaying the program and the results of such program until the Trust finds a suitable alternative partner.

The Trust does not hold any Asset-Backed Commercial Paper investments. As a non-operating working interest owner, True has a minor exposure of approximately \$70,000 from oil sales marketed through SemCanada Crude Company, which filed for CCAA protection on July 22, 2008. True does not have any exposure to Lehman Brothers, which filed for Chapter 11 bankruptcy protection in the United States. To the best of True's knowledge, the Trust does not have any exposure to other US financial institutions.

During 2008 and in 2009, the Trust has been executing several strategies for dealing with these uncertain times.

True's corporate thrust in 2008 was to improve the Trust's balance sheet by reducing total outstanding debt and streamlining its operating cost structure. This strategy resulted in a reduced 2008 capital program of \$43 million, from \$88.9 million in 2007, and strategic divestitures which were expected to negatively impact reserves and production.

The consequence of this planned activity was total net debt levels decreased by \$35.3 million from \$250.3 million at December 31, 2007 to \$215.0 million at December 31, 2008. Total net debt excludes unrealized commodity contract assets and liabilities, future income taxes and asset retirement obligations. The accompanying reduction posted in reserves and production was within the planned parameters. Combined funding requirements for distributions declared and True's capital expenditures represented 102% of funds flow from operations in 2008. Since December 31, 2006, the Trust has managed to reduce total net debt by approximately \$60.8 million.

As a result of the continued deterioration in economic conditions, including the significant decline in crude oil prices, a weakening outlook for natural gas demand and a heightened risk in the credit markets at the start of 2009, True has deemed it prudent to suspend distributions to maintain corporate liquidity during the current financial turmoil and prevailing commodity price environment. Accordingly, no distributions will be paid in March 2009 to unitholders of record as at February 27, 2009. Distributions are to be reviewed monthly in the context of commodity prices, among other factors, and are subject to revision by the Board of Directors.

True continues to tighten its cost structure in the current economically challenging climate with forecasted cuts from 2008 levels of 30% to total operating expenses which includes general and administrative costs ("G&A") and lease operating costs in 2009.

As stated in the press release dated January 20, 2009 True has further reduced its capital budget in 2009 to \$15 million. True is not planning to drill any operated wells in the first half of 2009 and will limit capital spending to \$3 million in the first six months of 2009. The first half 2009 capital spending will be limited to the tie-in of two successful Saddlelake natural gas wells drilled in the fourth quarter of 2008, performing necessary maintenance programs

required due to extreme winter conditions in Alberta and Saskatchewan and focusing on increasing production from existing wells through workovers. True believes that industry costs currently do not reflect commodity prices and netback realizations. Our capital program for 2009 which is not expected to exceed \$15 million will reflect our future view of commodity pricing, available acquisition opportunities, and trends in operating costs. True is forecasting 2009 production volumes to average approximately 10,000 boe/d

True's operating forecast for 2009 which assumes a CAD\$/US\$ exchange rate of \$0.82, WTI oil price ranging from US\$50.00/bbl to US\$55.00/bbl, AECO natural gas price ranging from CAD\$5.46/GJ (\$6.00/mcf) to CAD\$5.92/GJ (\$6.50/mcf) and average annual production of approximately 10,000 boe/d generates cash flow from operations ranging from \$30 million to \$40 million, after deducting royalties, all operating costs (as reduced as discussed herein), G&A and debt servicing costs. Based on the foregoing assumptions and assuming 2009 distributions of \$1.6 million coupled with the planned capital budget of \$15 million the Trust would utilize between 40% - 60% of the Trust's forecasted funds flow from operations.

As an added layer of protection of its cash flow forecast, True has hedged approximately 60% of its estimated 2009 natural gas production for the period of March 1, 2009 to September 30, 2009 and 49% is hedged for the fourth quarter of 2009 at a combined fixed price of \$6.42 CAD per GJ (\$7.06/mcf). Approximately 18% of True's estimated natural gas production is hedged for the first half of 2010 at an average price of \$7.25 CAD per GJ (\$7.96/mcf). For the period of March 1, 2009 to December 31, 2009, True has entered into a crude oil collar to effectively hedge approximately 13% of its estimated 2009 crude oil production with a floor price of USD \$42.50/bbl and a ceiling price of USD \$65.60/bbl. True maintains an active commodity price risk management program focused on maintaining sufficient cash flow to fund its operations.

True's revolving term credit facility was renewed on June 27, 2008 and consists of a \$15 million demand operating facility provided by one Canadian bank and a \$137 million extendible revolving credit facility syndicated by two Canadian chartered banks, a Canadian financial institution, one institutional lender and a U.S. bank. \$12.5 million of the syndicated facility is with a US bank which may be required to be repaid or reallocated to one or more of the other four current members of the syndicate or a new member on June 28, 2009. The revolving period on the revolving term credit facility ends on June 26, 2009, unless extended for a further 364 day period. Should the facilities not be renewed they convert to 366 day non-revolving facilities on the renewal date. The borrowing base was renewed effective September 30, 2008 and is currently scheduled for review by March 31, 2009. The borrowing base will be subject to the lending syndicate's determination which is based upon the latest reserves information, their internal commodity price decks and other factors. In the event the borrowing base is lowered below the drawn credit facility at that time, any shortfall would be required to be repaid within 60 days of notification, or as otherwise agreed by the lending syndicate, and this funding would currently be expected to come from alternative sources of debt or equity financing or the proceeds from asset dispositions as available. As at December 31, 2008, there was approximately \$19.6 million not drawn (and was available) under these facilities.

There are currently no capital commitments, other than those associated with the Trust's credit facilities outlined above and its 2009 capital program of \$3 million for the first half of 2009. The Trust continually monitors its capital spending program in light of the recent volatility with respect to commodity prices and Canadian dollar exchange rates with the aim of ensuring the Trust will be able to meet future anticipated obligations incurred from normal ongoing operations with funds flow from operations and draws on the Trust's syndicated facility, as necessary. As announced on February 9, 2009, no Trust unit distributions will be paid in March 2009 to unitholders of record as at February 27, 2009. Distributions are to be reviewed monthly in the context of commodity prices, among other factors, and are subject to revision by the Board of Directors.

On June 15, 2006 the Trust completed a bought deal public offering of 86,250 7.5% convertible unsecured subordinated debentures at a price of \$1,000 per debenture for aggregate gross proceeds of \$86,250,000. The debentures have a face value of \$1,000 per debenture and a maturity date of June 30, 2011. The debentures bear interest at an annual rate of 7.50% payable semi-annually on June 30 and December 31 in each year commencing

December 31, 2006. The debentures are convertible at anytime at the option of the holders into Trust units of the Trust at a conversion price of \$16.00 per trust unit. The Trust will have the right to redeem all or a portion of the debentures at a price of \$1,050 per debenture after June 30, 2009 and on or before June 30, 2010 and at a price of \$1,025 per debenture after June 30, 2010 and before the maturity date. Upon maturity or redemption of the debentures, the Trust may, subject to notice and regulatory approval, pay the outstanding principal and premium (if any) on the debentures in cash or through the issue of additional Trust units at 95% of the weighted average trading price of the Trust units.

In November 2008, the Trust received Toronto Stock Exchange approval for its normal course issuer bid ("NCIB") program to repurchase up to 10% of the issued and outstanding 7.50% convertible unsecured subordinated debentures of the Trust ("Debentures") from December 1, 2008 to November 30, 2009. True believes that, from time to time, the market price of the Debentures may not fully reflect the underlying value of the Debentures and that at such times the purchase of the Debentures would be in the best interests of the Trust. Such purchases will increase the proportionate interest of, and may be advantageous to, all remaining holders of Debentures as well as holders of Trust units. To date, no repurchases of the Debentures have been made under this NCIB.

In August 2008, the Trust announced approval of the renewal of its normal course issuer bid program to repurchase up to 7.8 million of its outstanding Trust units during the period August 28, 2008 through August 27, 2009, subject to certain restrictions. As of December 31, 2008, the Trust has purchased 615,100 Trust units at a weighted average price of \$2.74 per Trust unit under the NCIB renewed on August 28, 2008. No further repurchases have been made in 2009 to date. This purchase is in response to True's belief that the current market price for Trust units does not reflect the underlying value of the Trust and the cancellation of the above purchased Trust Units will increase the proportionate interest of, and be advantageous to, all remaining unitholders. Future repurchases will be dependent on excess cash available after consideration of the Trust's priority uses of cash and the trading price of the Trust units.

As at February 27, 2009, the Trust had outstanding a total of 2,107,993 incentive units exercisable at an average exercise price of \$3.83 per unit, 294,026 exchangeable shares (convertible, as at February 27, 2009 into an aggregate of 312,467 Trust units, subject to further adjustments based on distributions made on Trust units), \$86.25 million principal amount of debentures convertible into trust units (at a conversion price of \$16.00 per Trust unit) and 78,496,581 Trust units. The details of the Trust's unit incentive rights outstanding for the year ended December 31, 2008 are summarized in note 9(b) of the financial statements.

Related Party Transactions

The Trust received legal services from a law firm in which a current director and corporate secretary is a partner. The fees charged are based on standard rates and time spent on matters pertaining to the Trust and its subsidiaries. The services provided were in the normal course of operations and have been recorded at the exchange amount. For the year ended December 31, 2008, legal fees received from the related party totaled \$0.6 million (2007: \$1.2 million).

Commitments

The Trust has committed to various corporate sponsorships extending to June 2011 at an estimated combined cost of up to \$228,000.

Off-Balance Sheet Arrangements

The Trust has certain lease agreements, including primarily office space leases, which were entered into in the normal course of operations. All leases have been treated as operating leases whereby the lease payments are included in operating expenses or G&A expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases in the balance sheet as of December 31, 2008.

The Trust is committed to payments under operating leases for office space as follows:

(\$000s) Year	Gross Amount	Expected Recoveries	Net amount
2009	1,824	1,034	790
2010	2,146	883	1,263
2011	2,207	897	1,310
2012	2,218	737	1,481
2013	2,218	737	1,481

Business Prospects and 2009 Year Outlook

The Trust continues to develop its core assets and conduct some exploration programs utilizing its large inventory of geological prospects. In addition, the Trust will continue to explore potential acquisition opportunities. Currently, the Trust's producing properties are located in Saskatchewan, Alberta and British Columbia.

The Trust continues to maintain a large undeveloped land base of approximately 586,087 (377,763 net) acres containing a significant multi-year drilling inventory.

True continues to tighten its cost structure in the current economically challenging climate with forecasted cuts of approximately 30% to total operating expenses which includes general and administrative costs ("G&A") and lease operating costs in 2009. As stated in the press release dated January 20, 2009 True has further reduced its capital budget in 2009 to \$15 million and is forecasting 2009 production volumes to average approximately 10,000 boe/d.

As an added layer of protection of its cash flow forecast, True has hedged approximately 60% of its estimated 2009 natural gas production for the period of March 1, 2009 to September 30, 2009 and 49% is hedged for the fourth quarter of 2009 at a combined fixed price of \$6.42 CAD per GJ (\$7.06/mcf). Approximately 18% of True's estimated natural gas production is hedged for the first half of 2010 at an average price of \$7.25 CAD per GJ (\$7.96/mcf). For the period of March 1, 2009 to December 31, 2009, True has entered into a crude oil collar to effectively hedge approximately 13% of its estimated 2009 crude oil production with a floor price of USD \$42.50/bbl and a ceiling price of USD \$65.60/bbl.

True's operating forecast for 2009 which assumes a CAD\$/US\$ exchange rate of \$0.82, WTI oil price ranging from US\$50.00/bbl to US\$55.00/bbl, AECO natural gas price ranging from CAD\$5.46/GJ (\$6.00/mcf) to CAD\$5.92/GJ (\$6.50/mcf) and average annual production of approximately 10,000 boe/d generates cash flow from operations ranging from \$30 million to \$40 million, after deducting royalties, all operating costs (as reduced as discussed herein), G&A and debt servicing costs. Based on the foregoing assumptions and assuming 2009 distributions of \$1.6 million coupled with the planned capital budget of \$15 million the Trust would utilize between 40% - 60% of the Trust's forecasted cash flow from operations.

True's 2009 capital program is not expected to exceed \$15 million and will limit the first half 2009 capital program to \$3 million. Given the nature of True's lands and their inherent advantage of year round access, True currently plans to spread its 2009 capital program evenly through the full year of 2009 to take advantage of reduced service costs during non-peak times. True will focus on increasing its farm-out activity in non-core areas. If the 2009 outlook for commodity prices improves, True would plan to increase its capital spending in third and fourth quarters of 2009 dependant upon cash flow.

Financial Reporting Update

Capital disclosures

The CICA issued a new accounting standard, Section 1535 "Capital Disclosures", which requires the disclosure of both qualitative and quantitative information that provides users of financial statements with information to evaluate the entity's objective, policies and processes for managing capital. This new section is effective for the Trust beginning January 1, 2008. Refer to note 18 of the financial statements for additional disclosure for this new section.

Financial instruments

Two new accounting standards were issued by the CICA, Section 3862 “Financial Instruments – Disclosures”, and Section 3863 “Financial Instruments – Presentation”. These sections replaced Section 3861 “Financial Instruments – Disclosure and Presentation” as adopted. The objective of Section 3862 is to provide users with information to evaluate the significance of the financial instruments on the entity’s financial position and performance, the nature and extent of risks arising from financial instruments, and how the entity manages those risks. The provisions of Section 3863 deal with the classification of financial instruments, related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset. These new sections are effective for the Trust beginning January 1, 2008. The additional disclosures required under these sections are included in note 18 of the financial statements.

Goodwill and intangible assets

In February 2008, the CICA issued a new accounting standard, Section 3064 – Goodwill and Intangible Assets, which replaces Section 3062 – Goodwill and Other Intangible Assets, and Section 3450 – Research and Development costs. The new section establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The section is effective for the Trust beginning January 1, 2009. Application of the new section is not currently expected to have any impact on the Trust’s financial statements.

International Financial Reporting Standards (“IFRS”)

On February 13, 2008 the CICA Accounting Standards Board announced that Canadian public reporting issuers will be required to report under International Financial Reporting Standards (“IFRS”), which will replace Canadian generally accepted accounting principles (“GAAP”) for years beginning on or after January 1, 2011. The transition date of January 1, 2011 will require restatement for comparative purposes, of amounts reported by the Trust for its year ended December 31, 2010, and of the opening balance sheet as at January 1, 2010. An internal project team has been set up to manage this transition and to ensure successful implementation within the required time frame. Current economic conditions may require re-allocation of resources available for the IFRS conversion project. The Trust has completed a high level analysis to determine the areas impacted by the conversion and is assessing the financial reporting impacts on the adoption of IFRS and, at this time, the impact on future financial position and results of operations has not yet been determined. True is also monitoring industry discussion regarding the replacement of the CICA’s Accounting Guideline 16, which is expected to have major implications for True’s current full cost accounting policies. The Trust anticipates a significant increase in disclosures resulting from the adoption of IFRS and is continuing to assess the level of this disclosure required and any necessary systems changes to gather and process the information. We will continue to monitor any changes in the adoption of IFRS and will update plans as necessary.

Business Risks and Uncertainties

General

True’s production and exploration activities are concentrated in the Western Canadian Sedimentary Basin, where activity is highly competitive and includes a variety of different sized companies ranging from smaller junior producers to the much larger integrated petroleum companies.

True is subject to the various types of business risks and uncertainties including:

- Finding and developing oil and natural gas reserves at economic costs;
- Production of oil and natural gas in commercial quantities; and
- Marketability of oil and natural gas produced.

In order to reduce exploration risk, the Trust strives to employ highly qualified and motivated professional employees with a demonstrated ability to generate quality proprietary geological and geophysical prospects. To help maximize drilling success, True combines exploration in areas that afford multi-zone prospect potential, targeting a range of low to moderate risk prospects with some exposure to select high-risk with high-reward opportunities. True also explores in areas where the Trust has significant drilling experience.

The Trust mitigates its risk related to producing hydrocarbons through the utilization of the most appropriate technology and information systems managed by qualified personnel. In addition, True seeks to maintain operational control of the majority of its prospects.

Oil and gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. In order to mitigate such risks, True conducts its operations at high standards and follows safety procedures intended to reduce the potential for personal injury to employees, contractors and the public at large. The Trust maintains current insurance coverage for general and comprehensive liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect changing corporate requirements, as well as industry standards and government regulations. True may periodically use financial or physical delivery hedges to reduce its exposure against the potential adverse impact of commodity price volatility, as governed by formal policies approved by senior management subject to controls established by the Board.

Environmental Regulations and Risks

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Environmental legislation in the Province of Alberta has been consolidated into the Environmental Protection and Enhancement Act (Alberta) (the "EPEA"), which came into force on September 1, 1993, and the Oil and Gas Conservation Act (Alberta) (the "OGCA"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the Climate Change and Emissions Management Amendment Act came into effect on July 1, 2007 ("CCEMAA"). Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund (the "Fund"). Industries can either choose one of these options or a combination thereof. Pursuant to CCEMAA and the Specified Gas Emitters Regulation, companies were obliged to reduce their emission intensity by 12% by March 31, 2008. Alberta industries have achieved 2.6 million tonnes of actual reduction, due to changes in operations and investing on verified offset projects. In addition, certain companies contributed \$40 million to the Fund. The Trust will be committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment, and will be taking such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which it

operates. The Trust believes that it is in material compliance with applicable environmental laws and regulations. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

On January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for in situ oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating carbon dioxide from other emissions supporting carbon capture and storage. In addition to this action plan, the Provincial Energy Strategy unveiled on December 11, 2008 is expected to, among other things, support the upgrading, refining and petrochemical clusters existing in the Province, market Alberta's energy internationally, review the emission targets and carbon charges applied to large facilities, and promote the innovation of energy technology by encouraging investment in research and development.

British Columbia's Environmental Assessment Act became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process. On February 27, 2007 the Government of British Columbia unveiled the Energy Plan outlining the Province's strategy towards the environment and which includes targeting for zero net greenhouse gas emissions, promoting new investments in innovation, and becoming the world's leader in sustainable environmental management. For this purpose, on December 18, 2007 proposals were sought for applications to the Innovative Clean Energy Fund, in order to attract new technologies that will help solve energy and environmental issues. With regards to the oil and gas industry the objective is to achieve clean energy through conservation and energy efficient practices, whilst competitiveness is advocated in order to attract investment for the development of the oil and gas sector. Among the changes to be implemented are: (i) a new of Net Profit Royalty Program; (ii) the creation of a Petroleum Registry; (iii) the establishment of an infrastructure royalty program (combining roads and pipelines); (iv) the elimination of routine flaring at producing wells; (v) the creation of policies and measures for the reduction of emissions; (vi) the development of unconventional resources such as tight gas and coal bed gas; and (vii) new the Oil and Gas Technology Transfer Incentive Program that encourages the research, development and use of innovative technologies to increase recoveries from existing reserves and promotes responsible development of new oil and gas reserves. Furthering these initiatives, the Provincial Government introduced on July 1, 2008, revenue-neutral carbon tax legislation that is applied to all fossil fuels used in the Province. The tax would be phased in, and the initial rate would be based on CO₂e of \$10 per tonne for the first six months of 2009 and \$15 per tonne for the last six months of 2009, following \$5 per tonne increases on July of every year until 2012. Tax credits and reductions will be used in order to offset the tax revenues that the Government would receive otherwise. On April 3, 2008, the Government of British Columbia introduced the Greenhouse Gas Reduction (Cap and Trade) Act which will allow the Province to participate in the Western Climate Initiative cap and trade systems being developed. The system establishes a limit on emissions, and allows regulated emitters to buy/sell emission allowances or offset emits. The emitter is obliged to obtain emission allowances (compliance units) equal to the amount of greenhouse gases emitted within a certain period of time, and that are supposed to be surrendered to the Government as compliance proof.

In December 2002, the Government of Canada ratified the Kyoto Protocol ("Kyoto Protocol"). The Kyoto Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. It is questionable, based on the Updated Action Plan announced by the Federal Government (see below), that the Kyoto Protocol target of 6% below 1990 emission levels will be enforced in Canada. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007. On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan") also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers

not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

In order to strengthen the Action Plan, on March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the "Updated Action Plan") which provides some additional guidance with respect to the Government's plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050. Details of the Updated Action Plan are provided in the Trust's Annual Information Form for the year ended December 31, 2007.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on the Trust and its operations and financial condition at this time.

Alberta Royalty Regime

On January 1, 2009, the Alberta Government implemented changes to royalty rates under a New Royalty Framework ("NRF") previously announced on October 25, 2007. In 2008, the Alberta Government also announced, but not yet enacted as of December 31, 2008, provisions that allow for transitional royalties ("Transitional Royalties") to the NRF for certain wells. These Transitional Royalties are not reflected in December 31, 2008 reserve report of the Trust's independent reserves evaluator, GLJ Petroleum Consultants Ltd. ("GLJ"). However, in conjunction with the 2008 year-end reserve evaluation, GLJ did provide analysis of the sensitivity calculation in respect of the Transitional Royalties for forecast drilling, utilizing the Consultants' Consensus Methodology recommended by the Society of Petroleum Engineers, Calgary Chapter (the "Consensus Methodology"). Based on public information available when the Trust's reserves were evaluated, the net present value of future net revenue of proved and proved plus probable reserves based on a 10% discount rate using the Consultants' Methodology taking into account the Transitional Royalties utilizing Consensus Methodology Prices would represent an increase of less than 0.5%, in each case, as compared to the existing royalty rules which exclude the Transitional Royalties. The proposed royalty changes are very sensitive to production rate and natural gas prices.

The majority of True's current Alberta wells are in the 500m to 1,000m depth range and typically produce at lower rates. The overall impact of the NRF is mitigated by the Trust's current Saskatchewan properties and the lower shallow gas Alberta natural gas rate royalty production in True's Alberta conventional oil and gas production portfolio. The NRF will impact future drilling decisions in order for the Trust to maintain acceptable rates of return on its capital deployed.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and are continuing in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns.

Substantial Capital Requirements

The Trust anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As the Trust's revenues may decline as a result of decreased commodity pricing, it may be required to reduce capital expenditures. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Trust to additional access to capital risk. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Trust. The inability of the Trust to access sufficient capital for its operations could have a material adverse effect on the Trust's business financial condition, results of operations and prospects.

Third Party Credit Risk

The Trust may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Trust, such failures may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Trust's ongoing capital program, potentially delaying the program and the results of such program until the Trust finds a suitable alternative partner.

Critical Accounting Estimates

The reader is advised that the critical accounting estimates, policies, and practices as described in the Trust's Management's Discussion and Analysis continue to be critical in determining True's financial results.

The reader is cautioned that the preparation of financial statements in accordance with GAAP requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. The following discussion outlines accounting policies and practices that are critical to determining True's financial results.

Reserves

The Trust uses the full cost method of accounting for oil and gas properties. Generally, all costs of exploring and developing oil and natural gas reserves are capitalized and depleted against associated oil and natural gas production using the unit-of-production method based on the estimated proved reserves using forecast pricing. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based upon available geological, geophysical, engineering and economic data. Estimated reserves are also utilized by True's bank in determining credit facilities. Reserves affect net income through depletion and the ceiling test calculation. Estimating reserves is very complex, requiring many judgments based on available geological, geophysical, engineering and economic data. Changes in these judgments could have a material impact on the estimated reserves. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available, and as the economic environment changes. Changes in these judgments and estimates could have a material impact on the financial results and financial condition.

Asset retirement obligations

The discounted, expected future cost of statutory, contractual or legal obligations to retire long-lived assets are recorded as an Asset Retirement Obligation ("ARO") liability with a corresponding increase to the carrying amount of the related asset. The recorded ARO liability increases over time to its future amount through accretion charges to

earnings. Revisions to the estimated amount or timing of the obligations are reflected as increases or decreases to the ARO liability. Amounts capitalized to the related assets are amortized to income consistent with the depletion or depreciation of the underlying asset.

Unit based compensation

Units granted under the Trust Incentive Plan to employees and the Board of Directors is accounted for in accordance with the fair-value based method of accounting. Accordingly, the stock based compensation expense is measured at the grant date based on the fair value, using the Black-Scholes model, and is expensed over the vesting period of the units. Determination of the fair value of units granted at the grant date requires judgment, including the expected unit price volatility.

Fair value of derivatives

The fair value or mark-to-market value of commodity contracts is based on the estimated amount that would have been received or paid to settle the contracts as at December 31, 2008, and may be different from what will eventually be realized. Changes in the fair value of the commodity contracts are recognized in the Consolidated Statements of Loss within the financial statements. The actual gains and losses realized on eventual cash settlement can vary due to subsequent fluctuations in commodity prices.

Accounts receivable

The Trust employs judgment to estimate the carrying value of accounts receivable. After making assessments of credit risk from customers and joint venture partners, the Trust may provide for an allowance for doubtful accounts as required. Actual accounts receivable amounts collected in future periods may differ from these estimates.

Income taxes

In following the liability method of accounting for income taxes, related assets and liabilities are recognized for the estimated tax consequences between amounts included in the financial statements and their tax base using substantively enacted future income tax rates. Timing of future revenue streams and future capital spending changes can affect the timing of any temporary differences, and accordingly affect the amount of the future income tax liability calculated at a point in time. These differences could materially impact earnings.

Litigation outcomes

The Trust is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Trust's favor, the Trust does not currently believe that the outcome of adverse decisions in any pending or threatened proceeding related to these and other matters or any amount which it may be required to pay by reason thereof would have a material adverse impact on its financial position or results of operations.

With the above risks and uncertainties the reader is cautioned that future events and results may vary substantially from that which True currently foresees.

Legal, Environmental Remediation and Other Contingent Matters

The Trust reviews legal, environmental remediation and other contingent matters to both determine whether a loss is probable based on judgment and interpretation of laws and regulations and determine that the loss can reasonably be estimated. When the loss is determined, it is charged to earnings. The Trust's management monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by the circumstances.

Controls and Procedures

Disclosure Controls and Procedures

The Trust's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Trust is made known to the Trust's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Trust in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Trust's disclosure controls and procedures at the financial year end of the Trust and have concluded that the Trust's disclosure controls and procedures are effective at the financial year end of the Trust for the foregoing purposes.

Internal Control over Financial Reporting

The Trust's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal control over financial reporting to provide reasonable assurance regarding the reliability of the Trust's financial reporting and the preparation of financial statements for external purposes in accordance with the Canadian GAAP. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Trust's internal control over financial reporting at the financial year end of the Trust and concluded that the Trust's internal control over financial reporting is effective, at the financial year end of the Trust, for the foregoing purpose.

The Trust is required to disclose herein any change in the Trust's internal control over financial reporting that occurred during the period beginning on October 1, 2008 and ended on December 31, 2008 that has materially affected, or is reasonably likely to materially affect, the Trust's internal control over financial reporting. No material changes in the Trust's internal control over financial reporting were identified during such period, that has materially affected, or are reasonably likely to materially affect, the Trust's internal control over financial reporting.

It should be noted that a control system, including the Trust's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Standardized Distributable Cash

The Canadian Securities Administrators revised and re-issued in July 2007 National Policy 41-201 "Income Trusts and Other Indirect Offerings", which includes disclosures regarding distributable cash for Income Trusts. Further, the Canadian Institute of Chartered Accountants ("CICA") issued the Interpretive Release "Standardized Distributable Cash in Income Trusts and Other Flow-Through Entities: Guidance on Preparation and Disclosure" (the "Release"). In the new guidance, sustainability concepts are discussed and standardized distributable cash is defined as cash flow from operating activities less adjustments for productive capacity maintenance, long-term unfunded contractual obligations and the effect of any foreseeable financing matters, related to debt covenants, which could impair True's ability to pay distributions or maintain productive capacity. This Management Discussion and Analysis is in all material respects in accordance with the recommendations provided in CICA's Release and NP 41-201.

(\$000s, except per unit amounts and ratios)	Years ended December 31,	
	2008	2007
Net loss	(19,590)	(24,267)
Cash flow from operating activities	78,784	82,206
Productive capacity maintenance ⁽¹⁾	(36,699)	(86,291)
Standardized distributable cash	42,085	(4,085)
Proceeds on sale of property, plant and equipment	44,340	31,808
Corporate and property acquisition and other capital expenditures	(6,303)	(2,561)
Net proceeds from issue of trust units	-	54,375
Repurchase of trust units under normal course issuer bid	(2,536)	(1,658)
Bank borrowings (debt repayment) and working capital changes and other	(41,252)	(4,428)
Cash Distributions declared	36,334	73,451
Accumulated distributions, beginning of year	215,167	141,716
Accumulated distributions, end of year	251,501	215,167
Standardized distributable cash per unit – basic	\$0.53	\$(0.05)
Standardized distributable cash per unit – diluted	\$0.53	\$(0.05)
Standardized distributable cash payout ratio ⁽²⁾	0.86	N/A
Distributions declared per unit for outstanding units in the period	0.46	0.96
Accumulated distributions per unit, beginning of year	4.08	3.12
Accumulated distributions per unit, end of year	4.54	4.08
Excess (shortfall) of net income over cash distributions declared	(55,924)	(97,718)
Excess of cash flow from operating activities over cash distributions declared	42,450	8,755

(1) Please refer to the discussion of productive capacity maintenance below

(2) Represents cash distributions declared divided by standardized distributable cash

True strives to fund both distributions and maintenance capital primarily from funds flow from operations. True's 2008 capital budget was initially set at approximately 40% to 60% of annual funds flow. Actual 2008 capital expenditures

represented 55% of 2008 funds flow, which was impacted by drastically lower prices in the fourth quarter of 2008. Property dispositions, equity issues or additional borrowings may be required from time to time to fund a portion of the distributions and/or capital expenditures to maintain or increase productive capacity may be required based on forecast levels of cash flow, capital efficiency and debt levels.

Productive capacity is the amount of capital funds required in a period for an enterprise to maintain its ability to generate future cash flow from operating activities at a constant level. As commodity prices can be volatile and short-term variations in production levels are often experienced in the oil and gas industry, True defines production capacity as production on a barrel of oil equivalent basis. A quantifiable measure for these short-term variations is not objectively determinable or verifiable due to various factors including the inability to distinguish natural production declines from the effect of production additions resulting from capital and optimization programs, and the effect of temporary production interruptions. As a result, the adjustment for productive capacity maintenance in True's calculation of standardized distributable cash is True's capital expenditures excluding the cost of any asset acquisition, corporate asset acquisitions or proceeds of any asset disposition. True believes that its capital programs based on 40% to 60% of forecasted funds flow including its current view of True's assets and opportunities and True's outlook for commodity prices and industry conditions in the medium term, should be sufficient to maintain True's productive capacity in the medium term. True sets its hurdle rates for evaluating potential development and optimization projects according to these parameters. Due to the risks inherent in the oil and natural gas industry, particularly True's exploration and development activities and inherent variations in commodity prices, there can be no assurance that capital programs, whether limited to excess of cash flow over distributions or not, will be sufficient to maintain or increase True's production levels or cash flow from operating activities. True's capital expenditures and production can be impacted by the timing of the capital program and spring break up associated with certain operating areas of its properties. As True strives to maintain sufficient credit facilities and appropriate levels of bank debt, this seasonality is not expected to influence True's distribution policies.

True's calculation of standardized distributable cash has no adjustment for long-term unfunded contractual obligations. True's only material long-term unfunded contractual obligation at this time is for asset retirement obligations. True's abandonment obligations are being funded on an annual basis with cash flow from operating activities. Cash flow from operating activities, used in our standardized distributable cash calculation, includes a deduction for abandonment expenditures incurred in the year. True currently has no financing restrictions on distributions arising from compliance with its debt covenants. True regularly monitors its current forecast debt levels to ensure debt covenants are not exceeded.

Distributions typically exceed net income as a result of non-cash items such as unit-based compensation, depletion, depreciation and accretion, unrealized loss (gain) on commodity contracts, and future income tax expense (recovery). These non-cash items generally result in a reduction to net income, with no impact to cash flow from operating activities. Therefore, distributions will exceed net income in most periods. In the event distributions exceed cash flow from operating activities and the requirements of True's capital program, the shortfall will typically be funded by a combination of available bank facilities, equity or debt issues, or the sale proceeds from non-core assets.

The Board of Directors and management regularly review the level of distributions. The board considers a number of factors, including expectations of future current commodity prices, hedge positions, production volumes, capital expenditure requirements, market conditions, the availability of debt and equity capital and other factors. As a result of the volatility in commodity prices, changes in production levels and capital expenditure requirements, there can be no certainty that True will be able to maintain current levels of distributions and distributions can and may fluctuate in the future.

Further to the announcement on February 9, 2009, as a result of the continued deterioration in economic conditions, including the significant decline in crude oil prices, a weakening outlook for natural gas demand and heightened risk in the credit markets at the start of 2009, the Trust has suspended its March 2009 distribution. Distributions are to be

reviewed monthly in the context of commodity prices, among other factors, and are subject to revision by the Board of Directors.

<i>(\$000s, except ratios)</i>	To December 31, 2008
Cumulative distributable cash from operations ⁽¹⁾	66,433
Proceeds on sale of property, plant and equipment	100,662
Corporate and property acquisitions and other capital expenditures	(26,186)
Net proceeds from issue of trust units	54,375
Proceeds from issue of convertible debentures, net of issue costs	82,261
Repurchase of trust units under normal course issuer bid	(4,194)
Funding from DRIP	42,909
Bank borrowings (debt repayment) and working capital changes and other	(64,759)
Cumulative cash distributions declared ⁽¹⁾	251,501
Standardized distributable cash payout ratio ⁽²⁾	3.79

(1) Subsequent to the November 2, 2005 reverse takeover of TKE Energy Trust

(2) Represents cumulative distributions declared divided by cumulative standardized distributable cash

Sensitivity Analysis

The table below shows sensitivities to funds flow as a result of product price and operational changes. This is based on actual average prices received for the fourth quarter of 2008 and average production volumes of 10,750 boe/d during that period, as well as the same level of debt outstanding at December 31, 2008. Diluted weighted average trust units is based upon the fourth quarter of 2008. These sensitivities are approximations only, and not necessarily valid under other significantly different production levels or product mixes. Hedging activities can significantly affect these sensitivities. Changes in any of these parameters will affect funds flow as shown in the table below:

Sensitivity Analysis	Funds Flow from Operations (annualized) (\$000s)	Funds Flow from Operations Per Diluted Unit (\$)
Change of US \$1/bbl WTI	1,400	0.02
Change of \$0.10/ mcf	1,100	0.01
Change of US \$0.01 Cdn/ US exchange rate	550	-
Change in prime of 1%	1,300	0.02

Selected Quarterly Consolidated Information

The following table sets forth selected consolidated financial information of the Trust for the eight most recently completed quarters at the end of 2008.

2008 – Quarter ended (unaudited) (\$000s, except per unit amounts)	March 31	June 30	Sept. 30	Dec. 31
Revenues before royalties and hedging	70,033	82,074	72,225	41,053
Funds flow from operations ⁽¹⁾	24,233	26,304	21,491	5,865
Funds flow from operations per unit ⁽¹⁾				
Basic	\$0.31	\$0.33	\$0.27	\$0.07
Diluted	\$0.30	\$0.33	\$0.27	\$0.07
Net income (loss)	(18,621)	(21,374)	29,939	(9,534)
Net income (loss) per unit				
Basic	\$(0.24)	\$(0.27)	\$0.38	\$(0.12)
Diluted	\$(0.24)	\$(0.27)	\$0.38	\$(0.12)
Net capital expenditures (cash)	2,862	(34,450)	13,779	16,471
Distributions declared	9,507	9,505	9,474	7,848
Distributions per unit	\$0.12	\$0.12	\$0.12	\$0.10
2007 – Quarter ended (unaudited) (\$000s, except per unit amounts)	March 31	June 30	Sept. 30	Dec. 31
Revenues before royalties and hedging	71,196	74,991	50,547	61,756
Funds flow from operations ⁽¹⁾	29,988	34,192	17,478	19,514
Funds flow from operations per unit ⁽¹⁾				
Basic	\$0.43	\$0.47	\$0.22	\$0.25
Diluted	\$0.42	\$0.45	\$0.22	\$0.25
Net income (loss)	(8,571)	1,741	(17,003)	(434)
Net income (loss) per unit				
Basic	\$(0.12)	\$0.02	\$(0.21)	\$(0.01)
Diluted	\$(0.12)	\$0.02	\$(0.21)	\$(0.01)
Net capital expenditures (cash)	27,915	6,739	7,562	14,828
Distributions declared	16,866	18,376	19,132	19,077
Distributions per unit	\$0.24	\$0.24	\$0.24	\$0.24

⁽¹⁾Refer to “Non-GAAP Measures” in respect of the term “funds flow from operations” and “funds flow from operations per unit”.

The quarterly results for 2008 compared to 2007 were impacted by dispositions, fluctuating commodity prices, higher operating costs and reduced capital spending.

During the first half of 2008, True was successful in completing the divestiture of its Doddsland-Stranraer property located in Saskatchewan and other non-core properties in Alberta for net proceeds of \$44.3 million; the net proceeds from the dispositions were used to pay down debt. The dispositions reduced production volumes by approximately 1,000 boe/d. In the fourth quarter of 2008, True closed the purchase of further working interests in the Mantario, Saskatchewan area for \$4.3 million in cash after adjustments. The tuck-in acquisition added approximately 225 bbls/d of heavy oil production. 2007 production volumes reflected the acquisitions of Shellbridge and Prairie Schooner completed in 2006, as well as dispositions made throughout the year, totaling approximately \$31.8 million in net proceeds.

In 2007, True invested \$87.3 million in exploration and development of which approximately 70% was spent by the first half of the year. This compares to True's expenditures in exploration and development in 2008 of \$36.7 million of which approximately 66% was spent in the second half of the year.

True's revenues, net loss, and funds flow from operations in 2007 and 2008 reflect its production base after considering the above noted acquisitions and dispositions, results of exploration and development expenditures, timing of plant turnarounds and other operational challenges, as well as fluctuations in commodity prices. In 2007, natural gas prices increased through to the second quarter; and after declining in the third quarter, natural gas prices were on the rise again. Crude oil prices in 2007 experienced increases throughout the year. In 2008, natural gas prices increased in the first and second quarters and experienced a down turn in the third and fourth quarters of

2008. Crude oil prices in 2008 experienced significant increases up to the third quarter before decreasing to lows not experienced since 2004.

The fluctuation in commodity prices, and production volumes over these periods resulted in a corresponding increase or decrease in the Trust's petroleum and natural gas revenue, net income and funds flow from operations in the respective periods. The net loss for 2007 reflects an increase in DD&A rates due to acquisitions closed in 2006 in conjunction with increased production volumes as well as a loss on commodity contracts largely composed of unrealized losses arising from fair value accounting as commodity prices increased in the fourth quarter. In 2008, the net loss reflects a decrease in the DD&A rates due to dispositions closed in 2007 and 2008 in combination with lower production volumes. The loss on commodity contracts increased in 2008 due to the strong commodity prices experienced in the year.

Selected Annual Information

Years ended December 31, (\$000s, except per unit amounts) (unaudited)	2008	2007	2006
Revenues before royalties and hedging	265,385	258,490	220,913
Funds flow from operations ⁽¹⁾	77,893	101,172	90,391
Funds flow from operations per unit ⁽¹⁾			
Basic	\$0.99	\$1.33	\$1.91
Diluted	\$0.98	\$1.33	\$1.87
Net loss	(19,590)	(24,267)	(233,564)
Net loss per unit			
Basic	\$(0.25)	\$(0.32)	\$(4.95)
Diluted	\$(0.25)	\$(0.32)	\$(4.95)
Net capital expenditures (cash)	(1,338)	57,094	91,498
Total assets	736,117	880,252	1,016,658
Total net debt ⁽²⁾	215,004	250,313	275,816
Long-term financial liabilities			
Future income taxes	42,777	67,366	123,861
Asset retirement obligations	33,682	28,373	26,605
Exchangeable shares of subsidiary	2,887	3,922	4,153
Production (boe/d)	11,867	16,139	13,861
Distributions declared	36,334	73,451	124,355
Distributions per unit ⁽³⁾	\$0.46	\$0.96	\$2.64

⁽¹⁾ Refer to "Non-GAAP Measures" in respect of the term "funds flow from operations" and "funds flow from operations per unit".

⁽²⁾ Net debt includes the net working capital deficiency before short-term commodity contract assets and liabilities and short-term future income tax assets and liabilities. Total net debt also includes the liability component of convertible debentures and excludes asset retirement obligations and the future income tax liability.

⁽³⁾ Restated for changes in accounting policies and to reflect the consolidation of units effective November 2, 2005.

TRUE ENERGY TRUST
CONSOLIDATED BALANCE SHEETS

As at December 31 (unaudited)

(\$000s)	2008	2007
ASSETS		
Current assets		
Accounts receivable	\$ 27,845	\$ 48,522
Marketable securities (note 4)	120	850
Deposits and prepaid expenses	5,969	6,096
Capital taxes recoverable	274	626
Commodity contract asset (note 18)	3,726	1,061
Future income taxes (note 13)	-	3,116
	<u>37,934</u>	<u>60,271</u>
Property, plant and equipment (note 5)	698,183	819,981
Total assets	<u>\$ 736,117</u>	<u>\$ 880,252</u>
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	\$ 34,128	\$ 52,188
Distribution payable to unitholders	1,570	6,337
Commodity contract liability (note 18)	-	11,404
Future income taxes (note 13)	1,100	-
	<u>36,798</u>	<u>69,929</u>
Long-term debt (note 6)	132,388	168,475
Convertible debentures (note 7)	81,124	79,407
Asset retirement obligations (note 8)	33,682	28,373
Future income taxes (note 13)	42,777	67,366
Total liabilities	<u>326,769</u>	<u>413,550</u>
NON-CONTROLLING INTEREST		
Exchangeable shares of subsidiary (note 9)	2,887	3,922
UNITHOLDERS' EQUITY		
Unitholders' capital (note 10)	917,012	925,573
Equity component of convertible debentures	5,119	5,119
Contributed surplus (note 11)	28,240	19,454
Accumulated other comprehensive income	(620)	-
Deficit	(543,290)	(487,366)
	<u>(543,910)</u>	<u>(487,366)</u>
Total unitholders' equity	<u>406,461</u>	<u>462,780</u>
Total liabilities and unitholders' equity	<u>\$ 736,117</u>	<u>\$ 880,252</u>

COMMITMENTS (note 17)

See accompanying notes to the consolidated financial statements.

TRUE ENERGY TRUST
CONSOLIDATED STATEMENTS OF LOSS AND COMPREHENSIVE LOSS
For the years ended December 31 (unaudited)

<u>(\$000s)</u>	<u>2008</u>	<u>2007</u>
REVENUES		
Petroleum and natural gas sales	\$ 265,385	\$ 258,490
Royalties	(54,562)	(47,004)
Loss on commodity contracts (note 18)	(14,154)	(3,852)
	<u>196,669</u>	<u>207,634</u>
EXPENSES		
Production	66,573	68,282
Transportation	7,047	7,938
General and administrative	15,958	18,186
Interest and financing charges	14,822	18,108
Unit-based compensation (notes 10 and 11)	1,395	2,001
Depletion, depreciation and accretion	128,932	171,484
Special meeting costs (note 14)	-	3,805
	<u>234,727</u>	<u>289,804</u>
LOSS BEFORE TAXES	(38,058)	(82,170)
TAXES		
Capital taxes	2,025	2,039
Future income tax recovery (note 13)	(20,410)	(59,847)
	<u>(18,385)</u>	<u>(57,808)</u>
NET LOSS BEFORE NON-CONTROLLING INTEREST	(19,673)	(24,362)
Non-controlling interest	(83)	(95)
NET LOSS	<u>(19,590)</u>	<u>(24,267)</u>
Net changes in cash flow hedges (net of tax of \$1.8 million) (note 18)	-	(3,749)
Unrealized loss on available for sale marketable securities (net of tax recovery of \$0.1 million) (note 4)	(620)	-
	<u>(620)</u>	<u>(3,749)</u>
COMPREHENSIVE LOSS	<u>\$ (20,210)</u>	<u>\$ (28,016)</u>
Net loss per trust unit		
Basic	\$(0.25)	\$ (0.32)
Diluted	\$(0.25)	\$ (0.32)

See accompanying notes to the consolidated financial statements.

TRUE ENERGY TRUST
CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY

For the years ended December 31 (unaudited)

(\$000s)	2008	2007
UNITHOLDERS' CAPITAL		
Balance, beginning of year	\$ 925,573	\$ 876,904
Issued for cash (net of issue costs of \$3.1 million)	-	54,375
Repurchased under normal course issuer bid	(9,513)	(5,842)
Exchangeable shares converted	952	136
Balance, end of year	<u>917,012</u>	<u>925,573</u>
EQUITY COMPONENT OF CONVERTIBLE DEBENTURES		
Balance, beginning and end of year	<u>5,119</u>	<u>5,119</u>
CONTRIBUTED SURPLUS		
Balance, beginning of year	19,454	12,818
Unit-based compensation expense (note 10 and 11)	1,869	4,249
Incentive units voluntarily surrendered	466	-
Reversal of prior period unit-based compensation expense for forfeitures of unvested incentive units	(526)	(1,797)
Adjustment for repurchase of units under normal course issuer bid	6,977	4,184
Balance, end of year	<u>28,240</u>	<u>19,454</u>
DEFICIT		
Balance, beginning of year	(487,366)	(389,745)
Net loss	(19,590)	(24,267)
Impact of changes in accounting policy for financial instruments (net of tax of \$0.05 million) (note 7)	-	97
Distributions declared	(36,334)	(73,451)
Balance, end of year	<u>(543,290)</u>	<u>(487,366)</u>
ACCUMULATED OTHER COMPREHENSIVE INCOME		
Balance, beginning of year	-	-
Impact of new cash flow hedge accounting standards (net of tax of \$1.8 million) (note 18)	-	3,749
Reclassification to earnings of net hedging gains on commodity contracts (net of tax of \$1.8 million) (note 18)	-	(3,749)
Unrealized loss on available for sale marketable securities (net of tax recovery of \$0.1 million) (note 4)	(620)	-
Balance, end of year	<u>(620)</u>	<u>-</u>
TOTAL UNITHOLDERS' EQUITY	<u>\$ 406,461</u>	<u>\$ 462,780</u>

See accompanying notes to the consolidated financial statements.

TRUE ENERGY TRUST
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the years ended December 31 (unaudited)

<u>(\$000s)</u>	<u>2008</u>	<u>2007</u>
Cash provided by (used in):		
CASH FLOW FROM OPERATING ACTIVITIES		
Net loss	\$ (19,590)	\$ (24,267)
Items not involving cash:		
Non-controlling interest (note 9)	(83)	(95)
Depletion, depreciation and accretion	128,932	171,484
Unit-based compensation (notes 10 and 11)	1,395	2,001
Unrealized loss (gain) on commodity contracts (note 18)	(14,068)	10,343
Accretion on convertible debentures	1,717	1,553
Future income tax recovery (note 13)	(20,410)	(59,847)
	<u>77,893</u>	<u>101,172</u>
Asset retirement costs incurred (note 8)	(2,603)	(835)
Change in non-cash working capital (note 12)	3,494	(18,131)
	<u>78,784</u>	<u>82,206</u>
CASH FLOW FROM (USED IN) FINANCING ACTIVITIES		
Increase (decrease) in bank debt	(36,087)	11,591
Obligations under capital lease	-	(111)
Issue of trust units for cash	-	57,523
Unit issue costs	-	(3,148)
Repurchase of trust units under normal course issuer bid	(2,536)	(1,658)
Distributions declared	(36,334)	(73,451)
	<u>(74,957)</u>	<u>(9,254)</u>
Change in non-cash working capital (note 12)	(4,873)	(2,060)
	<u>(79,830)</u>	<u>(11,314)</u>
CASH FLOW FROM (USED IN) INVESTING ACTIVITIES		
Additions to property, plant and equipment	(43,002)	(88,852)
Proceeds on sale of property, plant and equipment	44,340	31,808
Purchase of marketable securities (note 4)	-	(50)
	<u>1,338</u>	<u>(57,094)</u>
Change in non-cash working capital (note 12)	(292)	(13,798)
	<u>1,046</u>	<u>(70,892)</u>
Change in cash	-	-
Cash, beginning of year	-	-
Cash, end of year	<u>\$ -</u>	<u>\$ -</u>

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

1. STRUCTURE OF THE TRUST

True Energy Trust (“True” or the “Trust”) is an open-ended, unincorporated investment trust governed by the laws of the Province of Alberta.

The purpose of the Trust is to indirectly explore for, develop and hold interests in petroleum and natural gas properties, through investments in securities of subsidiaries and net profits interests in oil and natural gas properties. The business of the Trust is carried on by True Energy Inc. and its indirect wholly owned subsidiary True Energy Peru S.A.C. The Trust owns, directly and indirectly, 100% of the common shares, (excluding the exchangeable shares – see note 9) of True Energy Inc. and True Energy Peru S.A.C. The activities of True Energy Inc. are financed through interest bearing notes from the Trust and third party debt as described in the notes to the financial statements.

Pursuant to the terms of Net Profit Interest Agreements (the “NPI Agreements”), the Trust is entitled to a payment from True Energy Inc. each month equal to the amount by which 99% of the gross proceeds from the sale of production exceed certain deductible expenditures (as defined). Under the terms of the NPI Agreements, deductible expenditures may include amounts, determined on a discretionary basis, to fund capital expenditures, to repay third party debt and to provide for working capital required to carry out the operations of True Energy Inc. as applicable.

The Trust will make distributions to the Unitholders in amounts equal to all or any part of the net income of the Trust earned from interest income on the notes and from the income generated under the NPI Agreements, and from any dividends paid on the common shares of True Energy Inc., less any expenses of the Trust including interest on the convertible debentures.

2. SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Trust have been prepared by management in accordance with generally accepted accounting principles in Canada. The preparation of consolidated financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Amounts recorded for depreciation, depletion and amortization, asset retirement costs and obligations and amounts used for ceiling test and impairment calculations are based on estimates of natural gas, and crude oil reserves and future costs required to develop those reserves. Actual results could differ from those estimates. The consolidated financial statements have, in management’s opinion, been properly prepared using careful judgment and reasonable limits of materiality and within the framework of the significant policies summarized below.

a. Principles of Consolidation

The consolidated financial statements include the accounts of the Trust and its subsidiaries. Any reference to the “Trust” throughout these consolidated financial statements refers to the Trust and its subsidiaries. All inter-entity transactions have been eliminated.

b. Revenue Recognition

Revenues from the sale of petroleum and natural gas are recorded when title to the products transfers to the purchasers based on volumes delivered and contracted delivery points and prices.

c. Joint Interests

A significant portion of the Trust's exploration and development activities are conducted jointly with others and, accordingly, the financial statements reflect only the Trust's proportionate interest in such activities.

d. Petroleum and Natural Gas Properties

The Trust follows the full cost method of accounting for petroleum and natural gas operations whereby all costs related to the exploration and development of petroleum and natural gas reserves are capitalized. These costs include land acquisition costs, geological and geophysical expenses, the costs of drilling both productive and non-productive wells, directly related overhead and estimated abandonment costs. Proceeds from the disposal of properties are deducted from the full cost pool without recognition of a gain or loss unless such a sale would significantly alter the rate of depletion and depreciation.

e. Depletion and Depreciation

Depletion of petroleum and natural gas properties is provided using the unit-of-production method based on production volumes before royalties in relation to total estimated proved reserves as determined annually by independent engineers and calculated in accordance with National Instrument 51-101. Natural gas reserves and production are converted at the energy equivalent of six thousand cubic feet to one barrel of oil.

Calculations for depletion and depreciation of production equipment are based on total capitalized costs plus estimated future development costs of proved undeveloped reserves less the estimated net realizable value of production equipment and facilities after the proved reserves are fully produced. The costs of acquiring and evaluating unproved properties are excluded from depletion calculations. These properties are assessed periodically to ascertain whether impairment has occurred. When the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion.

Depreciation of office furniture and equipment is provided for on a 20% declining balance basis.

f. Ceiling Test

The Trust applies a two-stage ceiling test on the aggregate carrying value of its capitalized costs, which may be amortized against revenues of future periods. The first stage of this process is to ensure that such costs do not exceed the undiscounted future cash flows from production of proved reserves. Undiscounted future cash flows are calculated based on management's best estimate of forward indexed prices applied to estimated future production of proved reserves plus the carrying cost of undeveloped properties, less estimated future operating costs, royalties, future development costs and abandonment costs. When the carrying amount of a cost centre is not recoverable, the second stage of the process will determine the impairment whereby the cost centre would be written down to its fair value. The second stage requires the calculation of discounted future cash flows from proved plus probable reserves plus the carrying cost of undeveloped properties net of any impairment allowance. The fair value of proved and probable reserves is estimated using accepted present value techniques, which incorporate risks and other uncertainties when determining expected cash flows.

The cost of undeveloped properties is excluded from the impairment test described above and subject to a separate impairment test.

g. Asset Retirement Obligations

The Trust recognizes a liability for the future retirement obligations associated with the Trust's property, plant, and equipment. The fair value of the asset retirement obligation is recorded on a discounted basis. This amount is also capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the Trust settles the obligation.

h. Environmental Liabilities

The Trust records liabilities on an undiscounted basis for environmental remediation efforts that are likely to occur and where the cost can be reasonably estimated. The estimates, including associated legal costs, are based on available information using existing technology and enacted laws and regulations. The estimates are subject to revision in future periods based on actual costs incurred or new circumstances. Any amounts expected to be recovered from other parties, including insurers, are recorded as an asset separate from the associated liability.

i. Unit-based Compensation Plan

The Trust accounts for its Trust Unit Incentive Plan issued to employees and the Board of Directors using the fair value method. The fair value of each trust unit incentive is estimated on the date of the grant using the Black-Scholes options pricing model and charged to earnings over the vesting period with a corresponding increase to contributed surplus.

j. Income Taxes

Income taxes are recorded using the liability method of tax allocation. Future income tax assets and liabilities are determined based on “temporary differences” and are measured using the current, or substantively enacted, tax rates and laws expected to apply when these differences reverse. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized.

The Trust is a taxable entity under the Income Tax Act (Canada) and is currently taxable only on income that is not distributed or distributable to the unitholders.

k. Exchangeable Shares of Subsidiary

The exchangeable shares can be traded privately, thereby allowing holders of the exchangeable shares to dispose of them without having to exchange them for trust units, and consequently, they must be classified as a non-controlling interest outside of Unitholders' Equity.

l. Financial Instruments

All financial instruments, including all derivatives, are recognized on the balance sheet initially at fair value. Subsequent measurement of all financial assets and liabilities except those held-for-trading and available for sale are measured at amortized cost determined using the effective interest rate method. Held-for-trading financial assets are measured at fair value with changes in fair value recognized in income. Available-for-sale financial assets are measured at fair value with changes in fair value recognized in comprehensive income and reclassified to income when derecognized or impaired. The Trust has the following classifications:

Financial Assets and Liabilities	Category
Accounts receivable	Loans and receivables
Marketable securities	Available-for-sale
Risk management contracts	Held-for-trading
Accounts payable and accrued liabilities	Other liabilities
Distribution payable	Other liabilities
Long-term debt	Other liabilities
Convertible debentures	Other liabilities

Transaction costs attributable to financial instruments classified as other than held-for-trading are included in the recognized amount of the related financial instrument and recognized over the life of the resulting financial instrument.

The Trust utilizes financial derivatives and non-financial derivatives, such as commodity sales contracts requiring physical delivery, to manage the price risk attributable to anticipated sale of petroleum and natural gas production and foreign exchange exposures. The Trust does not enter into derivative financial instruments for trading or speculative purposes.

The derivative financial instruments are initiated within the guidelines of the Trust's risk management policy. This includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions.

The Trust has elected to account for its commodity sales and purchase contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts on an accrual basis rather than as derivatives. As such, physical sales and purchase contracts are not recorded at fair value on the balance sheet with changes in fair value included in earnings.

Subsequent changes in fair value of derivatives that are not designated or do not qualify for hedge accounting or normal purchase, sale or usage contracts are recognized in net income as incurred. For derivatives that are designated and qualify for cash flow hedge accounting at inception or the date of adoption, the effective portion of the change in fair value is recognized in other comprehensive income as incurred with the remaining portion of the change in fair value recognized in net income as incurred in the same financial statement caption as the hedged transaction. Net derivative gains (losses) in accumulated other comprehensive income are reclassified to net income in the same financial statement caption and future periods as the hedged transactions affect net income.

m. Capital Disclosures

The Trust considers its capital structure to include unitholders' equity, bank debt, convertible debentures and working capital. Handbook Section 1535, "Capital Disclosures" specify the disclosure of (i) an entity's objectives, policies and processes for managing capital; (ii) quantitative data about what the entity regards as capital; (iii) whether the entity has complied with any capital requirements; and (iv) if it has not complied, the consequences of such non-compliance.

n. Basic and Diluted per Trust Unit Calculations

Basic per trust unit amounts are calculated using the weighted average number of trust units outstanding during the period. The Trust uses the treasury stock method to determine the dilutive effect of trust incentive units. Under the treasury stock method, only "in the money" dilutive instruments impact the diluted calculations in computing diluted per unit amounts. The Trust uses the "if-converted" method to determine the dilutive effect of exchangeable shares and convertible debentures.

o. Measurement Uncertainty

The amounts recorded for depletion, depreciation and accretion expense, asset retirement obligations and amounts used in the impairment test for property, plant and equipment are based on estimates. These estimates include petroleum and natural gas reserves, future petroleum and natural gas prices, future interest rates and future costs required to develop those reserves as well as other fair value assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material.

p. Financial Presentation and Disclosure

Certain prior year comparative figures have been restated to conform to the current year's presentation.

3. CHANGES IN ACCOUNTING POLICIES AND RECENT ACCOUNTING PRONOUNCEMENTS

Effective January 1, 2008, the Trust adopted the following new accounting standards:

a. Capital disclosures

The CICA issued a new accounting standard, Section 1535 "Capital Disclosures", which requires the disclosure of both qualitative and quantitative information that provides users of financial statements with information to evaluate the entity's objective, policies and processes for managing capital. This new section is effective for the Trust beginning January 1, 2008. Refer to note 18 for additional disclosure for this new section.

b. Financial instruments

Two new accounting standards were issued by the CICA, Section 3862 "Financial Instruments – Disclosures", and Section 3863 "Financial Instruments – Presentation". These sections replace Section 3861 "Financial Instruments – Disclosure and Presentation" and are effective for the Trust beginning January 1, 2008. The objective of Section 3862 is to provide users with information to evaluate the significance of the financial instruments on the entity's financial position and performance, the nature and extent of risks arising from financial instruments, and how the entity manages those risks. The provisions of Section 3863 deal with the classification of financial instruments, related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset. The additional disclosures required under these sections are included in note 18.

Goodwill and intangible assets

In February 2008, the CICA issued a new accounting standard, Section 3064 – "Goodwill and Intangible Assets", which replaces Section 3062 – "Goodwill and Other Intangible Assets", and Section 3450 – "Research and Development Costs". The new section establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The section is effective for the Trust beginning January 1, 2009. Application of the new section is not currently expected to have any impact on the Trust's financial statements.

International Financial Reporting Standards ("IFRS")

On February 13, 2008 the CICA Accounting Standards Board announced that Canadian public reporting issuers will be required to report under International Financial Reporting Standards ("IFRS"), which will replace Canadian generally accepted accounting principles for years beginning on or after January 1, 2011. Currently, we are assessing the effects of adoption and developing a plan accordingly. We will continue to monitor any changes in the adoption of IFRS and will update plans as necessary.

4. MARKETABLE SECURITIES

The Trust's investment in Veraz Petroleum Ltd. is classified as available-for-sale and has been recorded at fair value. Changes in the fair value of the marketable securities are recorded net of the income tax effect to other comprehensive income.

5. PROPERTY, PLANT AND EQUIPMENT

(\$000s)

December 31, 2008	Cost	Accumulated depletion and depreciation	Net book value
Petroleum and natural gas properties	\$ 1,375,331	\$ 679,196	\$ 696,135
Office furniture and equipment	3,955	1,907	2,048
	\$ 1,379,286	\$ 681,103	\$ 698,183
December 31, 2007			
Petroleum and natural gas properties	\$ 1,370,219	\$ 552,899	\$ 817,320
Office furniture and equipment	4,092	1,431	2,661
	\$ 1,374,311	\$ 554,330	\$ 819,981

The Trust has included \$62.8 million (2007: \$56.6 million) for future development costs and excluded \$31.3 million (2007: \$37.8 million) for undeveloped land and \$42.5 million (2007: \$47.6 million) for estimated salvage from the depletion calculation during the year ended December 31, 2008.

For the year ended December 31, 2008, the Trust capitalized \$2.4 million of general and administrative expenses and \$0.6 million, including the future tax effect thereon of \$0.1 million, of unit-based compensation expense directly related to exploration and development activities.

The Trust performed a ceiling test calculation at December 31, 2008 resulting in undiscounted cash flows from proved reserves and the undeveloped properties not exceeding the carrying value of oil and gas assets. Consequently, True performed stage two of the ceiling test assessing whether discounted future cash flows from the production of proved plus probable reserves plus the carrying cost of undeveloped properties, net of any impairment allowance, exceeds the carrying value of its petroleum and natural gas properties. No impairment in oil and gas assets was identified as at December 31, 2008 and 2007.

The prices used in the ceiling test evaluation of the Trust's crude oil and natural gas reserves at December 31, 2008 were based on the following benchmark price forecasts adjusted for quality and transportation differentials:

Year	Hardisty Heavy Crude Oil (\$/bbl)	Edmonton Light Sweet Crude Oil (\$/bbl)	AECO Natural Gas (\$/mmbtu)
2009	45.72	67.85	7.05
2010	53.48	78.24	7.46
2011	58.70	84.96	7.67
2012	63.59	90.46	7.92
2013	67.41	95.73	8.16
2014	68.80	97.68	8.18
2015	70.34	99.66	8.19
2016	71.77	101.66	8.18
2017	73.23	103.66	8.20
2018	74.70	105.78	8.22
2019	76.21	107.90	8.23
Percentage increase each year after 2019	2%	2%	nil

6. LONG-TERM DEBT

(\$000s)	2008	2007
Operating facility	\$ 7,388	\$ 10,475
Revolving term facility	125,000	158,000
Balance, end of year	\$ 132,388	\$ 168,475

The credit facility was renewed on June 27, 2008 and consists of a \$15 million demand operating facility provided by one Canadian bank and \$137 million extendible revolving term credit facility syndicated by two Canadian chartered banks, a Canadian financial institution, one institutional lender and a U.S. bank. Amounts borrowed under the credit facility bear interest at a floating rate based on the applicable Canadian prime rate, U.S. base rates, LIBOR rates, plus between 0.10% and 2.05%, depending on the types of borrowings and the Trust's debt to cash flow ratio. Security is provided by a \$400 million debenture containing a first ranking security interest on all of the Trust's assets. The credit facility is secured against all the assets of True Energy Inc., the Trust and all material subsidiaries. True has provided a negative pledge and undertaking to provide fixed charges over major petroleum and natural gas reserves in certain circumstances. A standby fee is charged on between 0.150% and 0.400% on the undrawn portion of the facility, depending on the Trust's debt to cash flow ratio.

As at December 31, 2008, approximately \$19.6 million was not drawn under the existing facilities.

The revolving period on the revolving term credit facility ends on June 26, 2009, unless extended for a further 364 day period. Should the facilities not be renewed they convert to 366 day non-revolving term facilities on the renewal date. The borrowing base was renewed effective September 30, 2008 and is currently scheduled for review on March 31, 2009. The borrowing base will be subject to the lending syndicate's determination which is based upon the latest reserves information, their internal commodity price decks and other factors. In the event the borrowing base is lowered below the drawn credit facility at that time, any shortfall would be required to be repaid within 60 days of notification, or as otherwise agreed by the lending syndicate, and this funding would currently be expected to come from alternative sources of debt or equity financing or the proceeds from asset dispositions as available.

Payment will not be required under the revolving term facility for more than 365 days from the balance sheet date as at December 31, 2008 as there is sufficient availability under the revolving term credit facility to also cover the operating facility and, as such, the entire credit facility has been classified as long-term. \$12.5 million of the syndicated facility is with a US bank which may be required to be repaid or reallocated to one or more of the other four current members of the syndicate or a new member on June 28, 2009, if not renewed by the US bank.

7. CONVERTIBLE DEBENTURES

On June 15, 2006, the Trust completed a public offering of 86,250 7.5% convertible unsecured subordinated debentures at a price of \$1,000 per debenture for aggregate gross proceeds of \$86,250,000.

The convertible debentures have a face value of \$1,000 per debenture and a maturity date of June 30, 2011. The convertible debentures bear interest at an annual rate of 7.50% payable semi-annually on June 30 and December 31 in each year. The debentures are convertible at anytime at the option of the holders into trust units of the Trust at a conversion price of \$16.00 per Trust unit. The Trust will have the right to redeem all or a portion of the debentures at a price of \$1,050 per debenture after June 30, 2009 and on or before June 30, 2010 and at a price of \$1,025 per debenture after June 30, 2010 and before the maturity date. Upon maturity or redemption of the debentures, the Trust may, subject to notice and regulatory approval, pay the outstanding principal and premium (if any) on the debentures in cash or through the issue of additional Trust units at 95% of a weighted average trading price of the Trust units.

The debentures were initially recorded at the fair value of the obligation without the conversion feature. This fair value to make future payments of principal and interest was initially determined to be \$81.1 million. The difference between the principal amount of \$86.3 million and the fair value of the obligation is \$5.1 million and has been recorded in unitholders' equity as the fair value of the conversion feature of the debentures. Issue costs of \$4.0 million were classified as deferred financing charges, and prior to January 1, 2007, were amortized on a straight-line basis over the term of the debentures. As a consequence of adopting new financial instruments standards effective January 1, 2007, the balance of deferred financing charges or transaction costs were recorded against the debt component of convertible debentures and restated as if the effective interest rate method had always been applied over the life of the debentures with a resulting \$0.1 million adjustment (net of tax of \$0.05 million) against the deficit. The adjustment to debentures is noted in the table below. The debt component of the convertible debentures will accrete up to the principal balance at maturity. The accretion and the interest paid are expensed as interest and financing charges in the consolidated statement of operations.

The following table shows the convertible debenture activities for the years ended December 31, 2008 and 2007:

Convertible debentures

	Number of Debentures	Debt Component (\$000s)	Equity Component (\$000s)
Balance, December 31, 2006	86,250	\$ 81,551	\$ 5,119
Impact of change in accounting policy for financial instruments on January 1, 2007	-	(3,697)	-
Accretion	-	1,553	-
Balance, December 31, 2007	86,250	\$ 79,407	\$ 5,119
Accretion	-	1,717	-
Balance, December 31, 2008	86,250	\$ 81,124	\$ 5,119

In November 2008, the Trust received Toronto Stock Exchange approval for its normal course issuer bid program ("NCIB") to repurchase up to 10% of the issued and outstanding 7.50% convertible unsecured subordinated debentures of the Trust from December 1, 2008 to November 30, 2009. As of December 31, 2008 there were no repurchases of convertible debentures under the NCIB.

8. ASSET RETIREMENT OBLIGATIONS

The Trust's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Trust estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations is approximately \$77.6 million which will be incurred between 2009 and 2053. A credit-adjusted risk-free rate of 8 percent and an inflation rate of 2.4 percent were used to calculate the fair value of the asset retirement obligation.

(\$000s)	2008	2007
Balance, beginning of year	\$ 28,373	\$ 26,605
Liabilities incurred on development activities	784	433
Changes in prior period estimates	8,302	960
Liabilities released on dispositions	(3,333)	(927)
Liabilities settled during the year	(2,603)	(835)
Accretion expense	2,159	2,137
Balance, end of year	\$ 33,682	\$ 28,373

9. EXCHANGEABLE SHARES OF SUBSIDIARY / NON-CONTROLLING INTEREST

Authorized:

Unlimited number of exchangeable shares, issuable in series of which the first series in an unlimited number is designated for Series A exchangeable shares.

	December 31, 2008		December 31, 2007	
	Number	Amount (\$000s)	Number	Amount (\$000s)
Balance, beginning of year	390,276	\$ 3,922	403,536	\$ 4,153
Non-controlling interest recovery	-	(83)	-	(95)
Exchanged for trust units	(96,250)	(952)	(13,260)	(136)
Balance, end of year	294,026	\$2,887	390,276	\$ 3,922

The Series A exchangeable shares are non-voting (but holders are entitled to equivalent voting rights in the Trust) and can be converted, at the option of the holder into trust units at any time. If the number of exchangeable shares outstanding is less than 180,000, the Trust can elect to redeem the exchangeable shares for trust units or an amount in cash equal to the amount determined by multiplying the exchangeable ratio on the last business day prior to the redemption date by the current market price of a trust unit on the last business day prior to such redemption date. The number of trust units issued upon conversion is based on the exchange ratio in effect on the date of conversion. The exchange ratio is calculated monthly based on the five day weighted average trust unit trading price preceding the monthly effective date. The exchangeable shares are not eligible for cash distributions; however cash distributions will increase the exchange ratio.

As at December 31, 2008, the exchange ratio was 1.0218 (2007 – 0.8604)

Retraction of Exchangeable Shares

Exchangeable shares may be redeemed at any time by delivering the share certificates to the Trustee, together with a properly completed retraction request. The retraction price will be satisfied with trust units equal to the amount determined by multiplying the exchange ratio on the last business day prior to the retraction date by the number of exchangeable shares redeemed.

Redemption of Exchangeable Shares

On January 15, 2010, the exchangeable shares will be redeemed by the Trust unless the Board of Directors of True Energy Inc. elects to extend the redemption period. The exchangeable shares generally will be redeemed issuing units for an amount equivalent to the value of the exchangeable shares at the current exchange ratio.

10. UNITHOLDERS' CAPITAL

a. Trust Units

The Trust Indenture provides that an unlimited number of trust units may be authorized and issued. Each trust unit is transferable, carries the right to one vote and represents an equal undivided beneficial interest in any distributions from the Trust and in the net assets of the Trust in the event of termination or winding-up of the Trust. All trust units are of the same class with equal rights and privileges. Trust units are redeemable at any time at the lesser of 90% of the market price (as determined in accordance with the Trust Indenture) and the closing price of the trust units on the date tendered for redemption to a maximum, unless waived, of \$250,000 per calendar month in which case the redemption price is payable by distributing notes of the Trust's subsidiary or notes of the Trust.

	2008		2007	
	Number	Amount (\$000s)	Number	Amount (\$000s)
Balance, beginning of year	79,216,046	\$ 925,573	70,275,703	\$ 876,904
Issued for cash (net of issue costs of \$3.1 million)	-	-	9,430,000	54,375
Repurchased under normal course issuer bid	(814,300)	(9,513)	(500,000)	(5,842)
Exchangeable shares converted	94,835	952	10,343	136
Balance, end of year	78,496,581	\$ 917,012	79,216,046	\$ 925,573

In August 2008, the Trust announced approval of the renewal of its normal course issuer bid ("NCIB") program to repurchase up to 7.8 million of its outstanding trust units during the period August 28, 2008 through August 27, 2009, subject to certain restrictions. As of December 31, 2008, the Trust has purchased 615,100 trust units at a weighted average price of \$2.74 per trust unit under the NCIB renewed on August 28, 2008.

b. Trust Unit Incentive Plan

The Trust has a trust unit incentive plan where the Trust may grant trust unit incentive rights to its directors, officers and employees. Under this plan, the exercise price of each trust unit incentive right initially equals the market price of the Company's stock on the date of grant. The maximum term of an incentive right is five years.

The grant price per Incentive Right ("Grant Price") shall be equal to the per trust unit closing price on the trading day immediately preceding the date of grant, unless otherwise permitted. Under the terms of the Incentive Plan, the exercise price of each Incentive Right is initially equal to the Grant Price and thereafter is reduced pursuant to a formula. This formula provides that the exercise price of each Incentive Right is reduced by any decreases in the daily closing price on the Toronto Stock Exchange of the Trust Units, provided, however, that such decrease in the exercise price will not exceed the amount of Trust unit distributions. In no case may the exercise price be less than \$0.001 per Trust Unit and a participant may elect to have the exercise price equal the Grant Price. Incentive Rights are non-transferable or assignable except in accordance with the Incentive Plan and the holding of Incentive Rights shall not entitle a holder to any rights as a Unitholder of True Energy Trust. Incentive rights, entitling the holder to purchase units from the Trust, have been granted to directors, officers, employees and service providers of the Trust. One third of the initial grant of trust unit incentive rights normally vest on each of the first, second, and third anniversary from the date of grant.

The following tables summarize information regarding trust unit incentive rights for the years ended December 31, 2008 and 2007:

Unit Rights Continuity

	Weighted Average Exercise Price ^(a)	Number
Balance, December 31, 2006	\$ 14.18	5,429,831
Granted	\$ 5.06	3,181,500
Forfeited and cancelled	\$ 12.50	(2,679,334)
Balance, December 31, 2007	\$ 9.18	5,931,997
Granted	\$ 2.89	578,500
Forfeited and cancelled ^(b)	\$ 11.35	(3,809,997)
Balance, December 31, 2008	\$ 3.97	2,700,500

(a) Exercise prices reflect grant prices less reduction in exercise prices.

(b) Total forfeited and cancelled in the year ended December 31, 2008 includes 2,191,250 incentive units which were voluntarily surrendered by existing employees, directors, and consultants of the Trust and were cancelled in July 2008.

Unit Rights Outstanding, December 31, 2008

Exercise Price Before Price Reductions	Exercise Price Net of Reductions	At Dec. 31, 2008	Outstanding		Exercisable	
			Weighted Average Exercise Price Net of Price Reductions	Weighted Average Remaining Contractual Life	At Dec. 31, 2008	Exercise Price Net of Price Reductions
\$ 1.68 - \$ 2.92	\$ 1.66 - \$ 2.49	1,018,000	\$ 2.30	4.2	252,981	\$ 2.49
\$ 3.02 - \$ 4.55	\$ 2.60 - \$ 4.31	279,500	\$ 3.54	4.5	-	-
\$ 4.98 - \$ 6.70	\$ 4.25 - \$ 5.59	1,378,000	\$ 5.06	3.4	459,316	\$ 5.06
\$20.40 - \$20.40	\$16.97 - \$16.97	25,000	\$ 16.97	1.9	25,000	\$ 16.97
\$ 1.68 - \$20.40	\$ 1.66 - \$16.97	2,700,500	\$ 3.97	3.8	737,297	\$ 3.73

Unit Rights Outstanding, December 31, 2007

Exercise Price Before Price Reductions	Exercise Price Net of Reductions	At Dec. 31, 2007	Outstanding		Exercisable	
			Weighted Average Exercise Price Net of Price Reductions	Weighted Average Remaining Contractual Life	At Dec. 31, 2007	Exercise Price Net of Price Reductions
\$ 2.92 - \$ 6.70	\$ 2.92 - \$ 6.13	2,745,000	\$ 4.56	4.6	-	N/A
\$10.58 - \$12.53	\$ 9.27 - \$11.12	914,998	\$ 9.56	3.8	361,648	\$ 9.54
\$13.74 - \$14.83	\$11.75 - \$12.92	527,166	\$ 12.11	3.5	213,497	\$ 12.17
\$15.92 - \$16.70	\$13.37 - \$14.28	92,500	\$ 13.74	3.3	48,334	\$ 13.80
\$18.25 - \$20.98	\$15.27 - \$18.22	1,652,333	\$ 15.46	2.9	1,620,665	\$ 15.41
\$ 2.92 - \$20.98	\$ 2.92 - \$18.22	5,931,997	\$ 9.18	3.9	2,244,144	\$ 14.12

c. Employee Trust Unit Savings Plan

Effective October 1, 2006, the Trust introduced an employee trust unit savings plan for the benefit of all employees. Under the savings plan, employees may elect to contribute up to 10 percent of their salary and contributions are used to fund the acquisition of trust units. The Trust matches employee contributions at a rate of \$1.00 for each \$1.00 contributed. Trust units are purchased in the open market by the plan administrator, an investment firm, on behalf of the participants in the plan. For the year ended December 31, 2008, the Trust matched \$0.5 million (2007 - \$0.5 million) under the plan. Effective for March 2009, the Trust has suspended matching contributions under the plan until further notice.

11. CONTRIBUTED SURPLUS

(\$000s)	2008	2007
Balance, beginning of year	\$ 19,454	\$ 12,818
Unit-based compensation expense	1,869	4,249
Incentive units voluntarily surrendered	466	-
Reversal of prior period unit-based compensation expense for forfeitures of unvested incentive units	(526)	(1,797)
Adjustment for repurchase of units under NCIB	6,977	4,184
Balance, end of year	\$ 28,240	\$ 19,454

Unit-based Compensation Expense

During the year ended December 31, 2008, the Trust granted 578,500 (2007: 3,181,500) unit incentive rights to employees. During the year ended December 31, 2008, the Trust recorded unit-based compensation of \$1.8 million, of which \$0.4 million was capitalized to property, plant and equipment.

The fair values of all incentive rights granted are estimated on the date of grant using the Black-Scholes option-pricing model. The weighted average fair market value of incentive rights granted during the years ended December 31, 2008 and 2007 and the assumptions used in their determination are as noted below:

	2008	2007
Assumptions:		
Risk free interest rate (%)	3	4
Expected life (years)	5	5
Expected volatility (%)	26-57	24-26
Results:		
Weighted average fair value of each incentive right granted	\$ 1.10	\$ 1.85

12. SUPPLEMENTAL CASH FLOW INFORMATION

Cash Interest and Taxes Paid

(\$000s)	2008	2007
Cash paid:		
Interest	\$ 14,041	\$ 16,566
Taxes (net of refunds)	\$ 1,409	\$ 4,378

Change in Non-cash Working Capital

(\$000s)	2008	2007
Changes in non-cash working capital items:		
Accounts receivable	\$ 20,677	\$ 24,677
Deposits and prepaid expenses	127	812
Accounts payable and accrued liabilities	(18,060)	(55,243)
Capital taxes recoverable	352	(2,139)
Distribution payable to unitholders	(4,767)	(2,096)
	\$ (1,671)	\$ (33,989)
Changes related to:		
Operating activities	\$ 3,494	\$ (18,131)
Financing activities	(4,873)	(2,060)
Investing activities	(292)	(13,798)
	\$ (1,671)	\$ (33,989)

13. INCOME TAXES

The Trust is a mutual fund trust as defined under the Income Tax Act (Canada). All taxable income earned by the Trust has been allocated to unitholders and such allocations are deducted for income tax purposes.

In June 2007, the government legislation implementing the new tax (the "SIFT tax") on publicly traded income trust and limited partnerships (Bill C-52) received third reading in the House of Commons and Royal Assent. For existing income trusts and limited partnerships, the SIFT tax will be effective in 2011 unless certain rules related to "undue expansion" are not adhered to. As such, the Trust would not be subject to the new measures until the 2011 taxation year provided the Trust continues to meet certain requirements.

In accordance with generally accepted accounting principles, prior to the enactment, the Trust did not record taxes on its temporary differences. As at December 31, 2008, the total "temporary difference" (tax basis exceeds accounting basis) in the Trust is \$9.8 million. As at December 31, 2008, the Trust's subsidiaries have a tax basis of approximately \$476 million that is available to shelter future taxable income. Included in this tax basis are estimated non-capital loss carry forwards of approximately \$39.7 million that expire in years through 2027. In addition, the Trust itself has approximately \$18.6 million of tax basis.

The provision for income taxes differs from the expected amount calculated by applying the combined Federal and Provincial corporate income tax rate of 30.10% (2007: 32.98%) to earnings before taxes. This difference results from the following items.

Years ended December 31 (\$000s)	2008	2007
Expected income tax expense (recovery)	\$ (11,456)	\$ (27,099)
Distributions deducted for tax purposes	(11,276)	(22,857)
Impact of SIFT legislation	-	(1,165)
Unit based compensation expense	420	660
Change in enacted tax rates	3,133	(9,444)
Other	(1,231)	58
Future income tax recovery	\$ (20,410)	\$ (59,847)

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

(\$000s)	2008	2007
Future income tax liabilities:		
Petroleum and natural gas properties	\$ (64,478)	\$ (87,564)
Commodity contract asset	(1,100)	-
Other	(565)	(565)
Future income tax assets:		
Future site restoration/asset retirement obligation	9,053	7,682
Share issue costs	656	1,345
Non-capital losses	11,331	10,502
Attributed Canadian Royalty Income	1,209	1,209
Commodity contract liability	-	3,116
Other	17	25
Net future income tax liability	\$ (43,877)	\$ (64,250)

14. SPECIAL MEETING COSTS

On January 15, 2007, the Trust announced its proposal to convert into an intermediate exploration and production company (the "Reorganization"). Pursuant to the Reorganization, it was contemplated that holders of Trust units of the Trust would receive an equal number of common shares of a newly formed corporation that would hold the assets previously held directly or indirectly by the Trust. The exchangeable shares were also to be exchanged for common shares based on the conversion ratio thereof. The Reorganization was subject to all required regulatory approvals and securityholder approval by at least 66 2/3% of the votes cast by unitholders of the Trust and holders of the exchangeable shares. At the Special and Annual Meeting held on March 30, 2007, the special resolution related to the Reorganization was not approved. As a result, the Reorganization was not completed. The Trust incurred \$3.8 million in costs for legal, financial advisory, accounting, unitholder solicitation services, printing, mailing and other expenses that are included as special meeting costs within the statement of income for the year ended December 31, 2007.

15. PER TRUST UNIT AMOUNTS

	2008	2007
Basic trust units outstanding, as at December 31	78,496,581	79,216,046
Dilutive effect of:		
Trust unit incentive rights outstanding	2,700,500	5,931,997
Units issuable for exchangeable shares	300,433	335,793
Units issuable for convertible debentures	5,390,625	5,390,625
Diluted trust units outstanding	86,888,139	90,874,461
Weighted average trust units outstanding	78,985,481	75,792,488
Dilutive effect of exchangeable shares, trust unit incentive plan and convertible debentures ⁽¹⁾	-	-
Diluted weighted average trust units outstanding	78,985,481	75,792,488

⁽¹⁾ A total of 2,700,500 (2007: 5,931,997) trust incentive units, 300,433 (2007: 335,793) exchangeable shares and 5,390,625 (2007: 5,390,625) trust units issuable pursuant to the conversion of convertible debentures were excluded from the calculation for the year ended December 31, 2008 as they were not dilutive.

16. RELATED PARTY TRANSACTIONS

During the year ended December 31, 2008, the Trust recorded fees of \$0.6 million (2007: \$1.2 million) for legal services provided by a firm in which a current director and corporate secretary is a partner. The services provided were made in the normal course of operations, on commercial terms, and therefore were recorded at the exchange amount. As at December 31, 2008, an amount due to this firm of \$0.1 million was included in accounts payable (2007: \$0.2 million).

17. COMMITMENTS

The Trust has committed to various corporate sponsorships extending to June 2011 at an estimated combined cost of up to \$228,000.

The Trust is committed to payments under operating leases for office space as follows:

(\$000s) Year	Gross Amount	Expected Recoveries	Net amount
2009	1,824	1,034	790
2010	2,146	883	1,263
2011	2,207	897	1,310
2012	2,218	737	1,481
2013	2,218	737	1,481

18. FINANCIAL RISK MANAGEMENT

a. Overview

The Trust has exposure to the following risks from its use of financial instruments:

- Credit risk
- Liquidity risk
- Market risk

This note presents information about the Trust's exposure to each of the above risks, the Trust's objectives, policies and processes for measuring and managing risk, and the Trust's management of capital. Further quantitative disclosures are included throughout these financial statements.

The Board of Directors has overall responsibility for the establishment and oversight of the Trust's risk management framework. The Board has implemented and monitors compliance with risk management policies.

The Trust's risk management policies are established to identify and analyze the risks faced by the Trust, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Trust's activities.

b. Credit risk

Credit risk is the risk of financial loss to the Trust if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Trust's trade receivables from joint venture partners, petroleum and natural gas marketers, and financial derivative counterparties.

A substantial portion of the Trust's accounts receivable are with customers and joint interest partners in the petroleum and natural gas industry and are subject to standard industry credit risks. The Trust sells substantially all of its production to eight primary purchasers under normal industry sale and payment terms. Purchasers of the Trust's natural gas, crude oil and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment.

The Trust has continued to closely monitor and reassess the creditworthiness of its counterparties, including financial institutions. This has resulted in the Trust reducing or mitigating its exposures to certain counterparties where it is deemed warranted and permitted under contractual terms.

Receivables from petroleum and natural gas marketers are normally collected on the 25th day of the month following production. The Trust's policy to mitigate credit risk associated with these balances is to establish marketing relationships with a range of medium to large purchasers and to conduct credit reviews of these parties on a regular basis. Joint venture receivables are typically collected within one to three months of the joint venture bill being issued to the partner. The Trust attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to expenditure. However, the receivables are from participants in the petroleum and natural gas sector, and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling, in addition further risk exists with joint venture partners as disagreements occasionally arise that increase the potential for non-collection. The Trust does not typically obtain collateral from petroleum and natural gas marketers or joint venture partners; however, in certain instances the Trust does have the ability to withhold production from joint venture partners in the event of non-payment.

As at December 31, 2008, accounts receivable was comprised of the following:

(\$000s)	
Trade accounts receivable	8,092
Accrued and other accounts receivable	19,753
	27,845

The carrying amount of accounts receivable and derivative assets represents the maximum credit exposure. The Trust has an allowance for doubtful accounts as at December 31, 2008 of \$0.5 million.

As at December 31, 2008 the Trust estimates its trade accounts receivables to be aged as follows:

Aging (\$000s)	
Not past due (less than 90 days)	3,128
Past due (90 or more days)	4,964
Total	8,092

After considering December 31, 2008 trade accounts payable from the same companies and cash receipts received subsequent to December 31, 2008, the Trust's trade receivables aged 90 or more days of approximately \$5.0 million are reduced to a net balance of approximately \$3.3 million.

Included in accrued and other accounts receivable are approximately \$6.9 million of amounts aged 90 or more days.

c. Liquidity risk

Liquidity risk is the risk that the Trust will not be able to meet its financial obligations as they are due. The Trust's approach to managing liquidity is to make reasonable efforts to sustain sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions without incurring unacceptable losses or risking harm to the Trust's reputation.

The Trust prepares annual capital expenditure budgets and determines unitholder distributions on a monthly basis. Capital expenditure budgets and levels of monthly unitholder distributions are regularly monitored and updated as considered necessary. Further, the Trust utilizes authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures. To facilitate the capital expenditure program, the Trust has a revolving reserve based credit facility, as outlined in note 6, which is at least reviewed annually by the lender. The Trust attempts to match its payment cycle with collection of petroleum and natural gas revenues on the 25th of each month. The Trust also mitigates liquidity risk by maintaining an insurance program to minimize exposure to insurable losses.

The following are the contractual maturities of financial liabilities as at December 31, 2008:

Financial liability (\$000s)	< 1 Year	1-2 Years	2-5 Years	Thereafter
Accounts payable and accrued liabilities	34,128	-	-	-
Distribution payable to unitholders	1,570	-	-	-
Bank debt – principal ⁽¹⁾	-	132,388	-	-
Convertible debentures – principal	-	-	86,250	-
Total	35,698	132,388	86,250	-

⁽¹⁾ Bank debt is based on a revolving term which is reviewed annually and converts to a 366 day non-revolving facility if not renewed.

The Trust's convertible debentures outstanding at December 31, 2008 bear interest at a coupon rate of 7.5%, which currently requires total annual interest payments of \$6.5 million. Interest due on the bank credit facility is calculated based upon floating rates.

d. Market risk

Market risk is the risk that changes in market prices, such as foreign exchange rates, commodity prices, and interest rates will affect the Trust's net earnings or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

Foreign currency exchange rate risk

Foreign currency exchange rate risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. Although substantially all of the Trust's petroleum and natural gas sales are denominated in Canadian dollars, the underlying market prices in Canada for petroleum and natural gas are impacted by changes in the exchange rate between the Canadian and United States dollar. As at December 31, 2008, if the Canadian/US dollar exchange rate had decreased by US\$0.01 with all other variables held constant, after tax net earnings for the year ended December 31, 2008 would have been approximately \$0.4 million lower.

An equal and opposite impact would have occurred to net earnings had the Canadian/US dollar exchange rate increased by US\$0.01.

The Trust had no forward exchange rate contracts in place as at or during the year ended December 31, 2008.

Commodity price risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by not only the relationship between the Canadian and United States dollar, as outlined above, but also world economic events that dictate the levels of supply and demand.

The Trust utilizes both financial derivatives and physical delivery sales contracts to manage commodity price risks. All such transactions are conducted in accordance with the risk management policy that has been approved by the Board of Directors.

The Trust's formal risk management policy permits management to use specified price risk management strategies for up to 50% of crude oil, natural gas and NGL production including fixed price contracts, costless collars and the purchase of floor price options, other derivative financial instruments, and physical delivery sales contracts to reduce the impact of price volatility and ensure minimum prices for a maximum of eighteen months beyond the current date. The program is designed to provide price protection on a portion of the Trust's future production in the event of adverse commodity price movement, while retaining significant exposure to upside price movements. By doing this, the Trust seeks to provide a measure of stability to funds flows from operations, as well as, to ensure True realizes positive economic returns from its capital developments and acquisition activities.

As at December 31, 2008, the Trust had entered into commodity price risk management arrangements as follows:

Type	Period	Volume	Price Floor	Price Ceiling	Index
Natural Gas fixed	Nov. 1, 2008 to March 31, 2009	5,275 GJ/day	\$ 7.61 CDN	\$ 7.61 CDN	AECO
Natural Gas fixed	Jan. 1, 2009 to March 31, 2009	5,275 GJ/day	\$ 7.86 CDN	\$ 7.86 CDN	AECO
Natural Gas fixed	April 1, 2009 to June 30, 2009	5,275 GJ/day	\$ 7.01 CDN	\$ 7.01 CDN	AECO
Natural Gas fixed	April 1, 2009 to June 30, 2009	5,275 GJ/day	\$ 7.015 CDN	\$ 7.015 CDN	AECO
Natural Gas fixed	July 1, 2009 to Sept. 30, 2009	5,000 GJ/day	\$ 7.49 CDN	\$ 7.49 CDN	AECO
Natural Gas fixed	Oct. 1, 2009 to Dec. 31, 2009	5,000 GJ/day	\$ 8.09 CDN	\$ 8.09 CDN	AECO
Natural Gas fixed	Jan. 1, 2010 to March 31, 2010	5,000 GJ/day	\$ 8.00 CDN	\$ 8.00 CDN	AECO

Subsequent to December 31, 2008, the Trust entered into commodity price risk management arrangements as follows:

Type	Period	Volume	Price Floor	Price Ceiling	Index
Natural Gas fixed	March 1, 2009 to June 30, 2009	5,000 GJ/day	\$ 4.89 CDN	\$ 4.89 CDN	AECO
Natural Gas fixed	March 1, 2009 to Sept. 30, 2009	4,500 GJ/day	\$ 5.00 CDN	\$ 5.00 CDN	AECO
Natural Gas fixed	March 1, 2009 to Dec. 31, 2009	5,000 GJ/day	\$ 5.90 CDN	\$ 5.90 CDN	AECO
Natural Gas fixed	July 1, 2009 to Sept. 30, 2009	5,000 GJ/day	\$ 5.41 CDN	\$ 5.41 CDN	AECO
Natural Gas fixed	Oct. 1, 2009 to Dec. 31, 2009	5,000 GJ/day	\$ 6.26 CDN	\$ 6.26 CDN	AECO
Natural Gas fixed	Jan. 1, 2010 to March 31, 2010	5,000 GJ/day	\$ 7.16 CDN	\$ 7.16 CDN	AECO
Natural Gas fixed	April 1, 2010 to June 30, 2010	5,000 GJ/day	\$ 6.59 CDN	\$ 6.59 CDN	AECO
Natural Gas call option	Jan. 1, 2010 to Dec. 31, 2010	5,000 GJ/day	-	\$ 8.05 CDN	AECO
Oil collar	March 1, 2009 to Dec. 31, 2009	500 bbl/d	\$ 42.50 US	\$ 65.60 US	WTI

For the years ended December 31, 2008 and 2007, the gain (loss) on commodity contracts was comprised of the following:

<i>(\$000s)</i>	2008	2007
Gain (loss) on commodity contracts		
Realized ⁽¹⁾	\$ (28,222)	\$ 6,491
Unrealized ⁽²⁾	14,068	(10,343)
	\$ (14,154)	\$ (3,852)

⁽¹⁾ Realized gains and losses on commodity contracts represent actual cash settlements and other amounts paid under these contracts.

⁽²⁾ Unrealized gains and losses on commodity contracts represent non-cash adjustments for changes in the fair value of these contracts during the period.

Effective January 1, 2007, True adopted accounting standards related to the new financial instruments accounting framework, which encompasses three new Canadian Institute of Chartered Accountant (“CICA”) Handbook Sections: 3855 “Financial Instruments – Recognition and Measurement”, 3865 “Hedges”, and 1530 “Comprehensive Income”.

On January 1, 2007, the Trust discontinued hedge accounting for all existing financial derivatives. As a result, a mark-to-market gain on the financial derivatives of \$3.7 million, net of existing unamortized deferred commodity contract premiums and the tax effect thereon was included in accumulated other comprehensive income as of January 1, 2007. These net derivative gains in accumulated other comprehensive income at January 1, 2007 were reclassified to income throughout 2007 as the original hedged transactions affected net earnings. From January 1, 2007 forward, the changes in fair value of such derivatives are recognized in net income when incurred.

The Trust has entered into a natural gas physical delivery sales contract to sell 5,275 GJ/day at a fixed price of \$7.29/GJ and \$7.90/GJ for the third and fourth quarter of 2009, respectively.

As at December 31, 2008, if oil and natural gas liquids prices had been US\$1 per barrel and natural gas prices \$0.10 per mcf lower, with all other variables held constant, after tax net earnings for the year ended December 31, 2008 would have been approximately \$1.8 million lower. An equal and opposite impact would have occurred to net earnings had oil and natural gas liquids prices been US\$1 per barrel and natural gas \$0.10 per mcf higher.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Trust is exposed to interest rate fluctuations on its bank debt which bears a floating rate of interest. As at December 31, 2008, if interest rates had been 1% lower with all other variables held constant, after tax net earnings for the year ended December 31, 2008 would have been approximately \$0.9 million higher, due to lower interest expense. An equal and opposite impact would have occurred to net earnings had interest rates been 1% higher.

The Trust had no interest rate swap or financial contracts in place as at or during the year ended December 31, 2008.

e. Capital management

The Trust's policy is to maintain a strong capital base so as to maintain investor, creditor and market confidence and to sustain the future development of the business. The Trust manages its capital structure and makes adjustments to it in the light of changes in economic conditions and the risk characteristics of the underlying petroleum and natural gas assets. The Trust considers its capital structure to include unitholders' equity, bank debt, convertible debentures and working capital. In order to maintain or adjust the capital structure, the Trust may from time to time issue trust units, adjust its capital spending, and/or dispose of certain assets to manage current and projected debt levels.

The Trust monitors capital based on the ratio of total net debt to annualized funds flow (the "ratio"). This ratio is calculated as total net debt, defined as outstanding bank debt, plus the liability component of convertible debentures, plus or minus working capital (excluding commodity contract assets and liabilities and future income tax assets or liabilities), divided by funds flow from operations (cash flow from operating activities before changes in non-cash working capital and deductions for asset retirement costs) for the most recent calendar quarter, annualized (multiplied by four). The total net debt to annualized funds flow ratio may increase at certain times as a result of acquisitions, fluctuations in commodity prices, timing of capital expenditures and other factors. In order to facilitate the management of this ratio, the Trust prepares annual capital expenditure budgets and sets unitholder distributions on a monthly basis. Capital expenditure budgets and levels of monthly unitholder distributions are reviewed and updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets and monthly unitholder distributions are approved by the Board of Directors.

Given the current uncertain economic conditions, the Trust revised the level of capital spending for 2009 and suspended its March 2009 distribution in order to increase financial flexibility. The Trust plans to continue to monitor forecasted debt levels to manage its operations within forecasted funds flow. The Trust expects the total net debt to annualized funds flow ratio to reflect the economic burdens experienced as a result of the recent downturn in the global economic environment. The Trust will continue to monitor developments within the global economic environment to consider the impacts on the current or future lending arrangements.

The Trust's long-term strategy, under a more stable economic environment, is to target a total net debt to annualized funds flow ratio of 2.0 times. As at December 31, 2008, the Trust's ratio of total net debt to annualized funds flow based on fourth quarter results and annual funds flow was 9.2 times and 2.8 times, respectively. The total net debt to annualized funds flow ratio as at December 31, 2008 increased from that at September 30, 2008 of 2.3 times due to lower funds flow from operations in the fourth quarter, which was significantly impacted by the decline in commodity prices, in addition to slightly higher total net debt due partially to the timing of the capital program in the second half of 2008. The Trust expects this ratio to decrease through 2009 as total net debt levels are reduced; True continues to take a balanced approach to the priority use of funds flows. The Debentures have a maturity date of June 30, 2011, upon maturity, the Trust may settle the principal in cash or issuance of additional Trust units. Excluding Debentures, net debt to annualized funds flow based on fourth quarter results and annual funds flow was 5.7 times and 1.7 times, respectively.

The calculation of total net debt and total net debt to cash flow is as follows:

(\$000s, except where noted)	Years ended December 31,	
	2008	2007
Long-term debt	132,388	168,475
Convertible debentures (liability component)	81,124	79,407
Working capital deficiency	1,492	2,431
Total net debt ⁽¹⁾ at year end	215,004	250,313
Debt to funds flow from operations ratio annualized		
Funds flow from operations annualized ⁽²⁾	23,460	78,056
Total net debt to periods funds flow from operations ratio annualized	9.2x	3.2x
Net debt ⁽¹⁾ (excluding convertible debentures)		
at quarter end	133,880	171,006
Net debt to periods funds flow from operations ratio annualized ⁽²⁾	5.7x	2.2x
Debt to funds flow from operations ratio		
Total net debt ⁽¹⁾ at year end	215,004	250,413
Funds flow from operations for the year	77,893	101,172
Total net debt to funds flow from operations ratio for the year	2.8x	2.5x
Net debt ⁽¹⁾ (excluding convertible debentures)		
at year end	133,880	171,006
Net debt to funds flow from operations ratio	1.7x	1.7x

⁽¹⁾ Net debt includes the net working capital deficiency (excess) before short-term commodity contract assets and liabilities and short-term future income tax assets and liabilities. Total net debt also includes the liability component of convertible debentures and excludes asset retirement obligations and the future income tax liability.

⁽²⁾ Debt to funds flow from operations ratio annualized is calculated based upon fourth quarter funds flow from operations annualized.

The Trust's credit facility is based on petroleum and natural gas reserves (see note 6). The credit facility outlines limitations on percentages of forecasted production, from external reserve engineer data, which may be hedged through financial commodity risk management contracts. The Trust also has outstanding normal course issuer bids for its convertible debentures and trust units, as detailed in note 7 and 10, respectively.

The Trust's ability to issue trust units is subject to external restrictions as a result of the Specified Investment Flow-Through Entities Legislation (the "SIFT tax") whereby the Trust may lose the benefit of a four year grandfathering period if the Trust exceeds the limits on the issuance of new trust units and convertible debt that constitute normal growth during the grandfathering period (subject to certain exceptions). The normal growth limits are calculated as a percentage of the Trust's market capitalization of approximately \$737 million on October 31, 2006, which the Trust may currently issue in additional equity without offending the normal growth guidelines between now and 2011. The normal growth restriction on trust unit issuance is monitored by management as part of the overall capital management objectives. The Trust is in compliance with the normal growth restrictions.

f. Fair value of financial instruments

The Trust's financial instruments as at December 31, 2008 include accounts receivable, deposits, marketable securities, commodity contract liability, accounts payable and accrued liabilities, distributions payable, long-term debt and convertible debentures. The fair value of accounts receivable, accounts payable and accrued liabilities and distributions payable approximate their carrying amounts due to their short-terms to maturity.

The fair value of commodity contracts is determined by discounting the difference between the contracted price and published forward price curves as at the balance sheet date, using the remaining contracted petroleum and natural gas volumes.

Long-term bank debt bears interest at a floating market rate and accordingly the fair market value approximates the carrying value.

The fair value of the convertible debentures of \$58.9 million is based on exchange traded values.

ADDITIONAL INFORMATION

Oil and Gas Working Interest ⁽¹⁾ Gross Reserves

Reconciliation of Proved Reserves ⁽²⁾

	Crude oil & NGL (mdbl)	Coal bed methane (mmcf)	Natural gas (mmcf)	Equivalent units (mboe)
December 31, 2007	10,778	1,812	99,036	27,587
Revision of previous estimates	100	41	4,200	806
Discoveries, extensions, infill drilling and improved recovery	489	52	4,768	1,291
Dispositions, net of acquisitions	82	-	(12,878)	(2,064)
Production	(1,581)	(249)	(16,157)	(4,314)
December 31, 2008	9,868	1,656	78,969	23,306
Proved plus probable reserves				
December 31, 2008	17,781	2,090	126,892	39,278
December 31, 2007	18,862	2,398	156,866	45,405

⁽¹⁾ "Working interest" refers to the Trust's working interest (operated or non-operated) share before deduction of royalties and without including any royalty interests of the Trust. Also referred to as Company Gross under NP 51-101.

⁽²⁾ Forecast prices before royalties.

True Energy Trust is a Calgary-based oil and natural gas trust. True is an open-ended, incorporated investment trust governed by the laws of the Province of Alberta. The purpose of the Trust is to indirectly explore for, develop and hold interests in petroleum and natural gas properties, through investments in securities of subsidiaries and net profits interests. The trust structure allows individual unitholders to participate in the cash flow of the business. Cash flow is realized from the Trust's subsidiaries' ownership of natural gas and petroleum properties and related facilities. Trust units and convertible debentures of True trade on the Toronto Stock Exchange ("TSX") under the symbols TUI.UN and TUI.DB, respectively. For further information, please contact:

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