



**For Immediate Release**  
**TSX: TUI.UN**

## **TRUE ENERGY TRUST ANNOUNCES FIRST QUARTER 2007 FINANCIAL RESULTS**

May 9, 2007 – (TSX: TUI.UN) True Energy Trust (“True” or the “Trust”) is pleased to announce its financial and operating results for the three months ended March 31, 2007. Highlights from the quarter include:

- During the first quarter of 2007, True achieved a 97% success rate in the drilling or participation in 34 (24.0 net) wells, resulting in 16 (8.6 net) natural gas wells, 15 (12.9 net) oil wells, 2 (2.0 net) stratagraphic test oil wells and 1 (0.5 net) dry holes. True successfully participated in or drilled 20 (10.4 net) wells in Alberta, and 14 (13.1 net) wells in Saskatchewan. The focus of True’s drilling program for the first quarter was on the West Central Alberta area and the further execution of True’s steam assisted gravity drainage (“SAGD”) project in the Kerrobert, Saskatchewan heavy oil area.
- Further to our press release dated March 15, 2007, we announced a restructuring of our senior management team for May 2007. We are pleased to announce that effective May 14, 2007 Wayne M. Chorney will join True in the capacity of President and Chief Operating Officer, bringing with him 23 years of industry experience.
- True generated average sales volumes for the 2007 first quarter of 18,461 boe per day, a 58% increase from 11,672 boe per day in the first quarter of 2006. Sales volumes decreased 7% from the fourth quarter 2006 volumes. This takes into account the impact of curtailment in production at the Trust’s Kerrobert project during offset drilling of additional wells necessary for further implementation of the SAGD project and reduced volumes of approximately 420 boe per day at the Trust’s Mantario heavy oil project due to reservoir performance. True is reviewing strategies to mitigate continued impact during the remainder of the year.
- Cash flow from operations\* for the first quarter was \$30.0 million on gross sales of \$71.2 million compared to cash flow from operations\* of \$19.0 million on gross sales of \$46.4 million for the same period in 2006. The increase in cash flow for the 2007 first quarter was the result of higher production volumes offset by lower natural gas prices. True’s realized natural gas prices in the 2007 first quarter averaged \$7.26/mcf compared to \$7.89/mcf for the first quarter of 2006.
- Total capital expenditures for 2007 first quarter, excluding corporate and property acquisitions and dispositions, were \$45.8 million compared to \$22.6 million in 2006. This increase reflects the execution of True’s successful drilling program in the quarter.
- Property dispositions were closed at the end of the first quarter for net proceeds of \$18.4 million.
- True recently entered into two new commodity price risk management contracts: 1) a oil put option with a West Texas Intermediate (“WTI”) reference crude oil price floor of US\$60.00 per barrel on 2,000 barrels per day for the third quarter of 2007; and 2) an additional WTI reference crude oil costless collar with a floor price of US\$65.00 per barrel and a ceiling price of US\$75.00 per barrel on 2,000 barrels per day for the fourth quarter of 2007 and the first quarter of 2008. True has currently hedged approximately 36% of current natural gas production for the second quarter and third quarters of 2007 and approximately 17% is hedged for the fourth quarter. Approximately 34% of current oil and NGL volume is hedged in the second quarter and 31% is hedged in each of the third and fourth quarters of 2007 and the first quarter of 2008.
- True maintains a large undeveloped land base of 1.0 million (0.7 million net) acres.

\* Refer to note (2) in the highlights section of the first quarter report in respect of the term “cash flow from operations”.

True’s first quarter report is presented below.

## HIGHLIGHTS

	Three months ended March 31	
	2007	2006
<b>FINANCIAL</b> <i>(unaudited)</i>		
<i>(CDN\$000s except unit and per unit amounts)</i>		
Revenue (before royalties and hedging <sup>(1)</sup> )	71,196	46,396
Cash flow from operations <sup>(2)</sup>	29,988	18,995
Per basic trust unit	\$0.43	\$0.52
Per diluted trust unit <sup>(3)</sup>	\$0.42	\$0.52
Net income (loss)	(8,571)	3,259
Per basic trust unit	\$(0.12)	\$0.09
Per diluted trust unit <sup>(3)</sup>	\$(0.12)	\$0.09
Distributions paid	16,866	26,150
Per unit	\$0.24	\$0.72
Payout ratio before DRIP <sup>(4) (5)</sup>	35%	246%
Payout ratio after DRIP <sup>(4) (5)</sup>	35%	234%
Exploration and development	45,841	22,451
Corporate and property acquisitions	705	124
Capital expenditures - cash	46,546	22,585
Property dispositions - cash	(18,443)	-
Other - non-cash	624	635
Total capital expenditures - net	28,727	23,220
Long-term debt	178,379	-
Convertible debentures	78,243	-
Bank debt	-	109,853
Working capital deficiency	32,450	29,758
Total net debt	289,072	139,611
Total assets	979,160	734,489
Unitholders' equity	481,547	375,189
<b>OPERATING</b>		
Daily sales volumes		
Crude oil and NGLs	(bbls/d)	6,472
Natural gas	(mcf/d)	71,931
Total oil equivalent	(boe/d)	18,461
Average prices		
Crude oil and NGLs	(\$/bbl)	41.26
Crude oil and NGLs (including hedging <sup>(1)</sup> )	(\$/bbl)	43.59
Natural gas	(\$/mcf)	7.26
Natural gas (including hedging <sup>(1)</sup> )	(\$/mcf)	7.15
Total oil equivalent	(\$/boe)	42.74
Total oil equivalent (including hedging <sup>(1)</sup> )	(\$/boe)	43.15
Statistics		
Operating netback	(\$/boe)	24.36
Operating netback (including hedging <sup>(1)</sup> )	(\$/boe)	24.76
Production expenses	(\$/boe)	9.01
General & administrative	(\$/boe)	2.95
Royalties as a % of sales after transportation		21%
		23%

	<b>Three months ended March 31</b>	
	<b>2007</b>	<b>2006</b>
<b>TRUST UNITS</b>		
Trust units outstanding	70,276,890	36,399,240
Trust unit incentive rights outstanding	5,227,333	3,273,165
Units issuable for exchangeable shares	303,547	334,372
Units issuable for convertible debentures	5,390,625	-
Diluted trust units outstanding	81,198,395	40,006,777
Diluted weighted average trust units <sup>(3)</sup>	70,579,317	36,630,699

#### **TRUST UNIT TRADING STATISTICS**

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

High	7.47	21.30
Low	4.87	12.99
Close	5.85	15.57
Average daily volume	601,721	388,648

<sup>(1)</sup> The Trust has entered into various commodity risk management contracts which are considered to be economic hedges. As disclosed in note 3 of the unaudited interim financial statements, effective January 1, 2007 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 in income for the period.

<sup>(2)</sup> The Management Discussion and Analysis ("MD&A") contains the term "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 cash flow from operations or cash flow from operations per trust unit may not be comparable with the calculation of similar measures for other entities. Management uses cash flow from operations to analyze operating performance and leverage and considers cash 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 cash flow from operations and cash flow from operating activities can be found in the MD&A. Cash flow from operations per trust unit is calculated using the diluted weighted average number of trust units for the period.

<sup>(3)</sup> In computing weighted average diluted earnings per trust unit for the three month period ended March 31, 2007 303,547 (2006: 334,372) trust units were added to the 70,275,770 (2006: 36,296,327) weighted average number of trust units outstanding during the period for the dilutive effect of exchangeable shares. A total of 5,227,333 (2006: 3,273,165) trust incentive units and 5,390,625 (2006: nil) trust units issuable pursuant to conversion of convertible debentures were excluded from the calculation of diluted earnings per trust unit for the three month period ended March 31, 2007 as they were not dilutive. To calculate weighted average diluted cash flow from operations for the three month period ended March 31, 2007, a total of \$1.98 million for interest accretion expense was added to the numerator and 5,390,625 trust units were added to the denominator for units issuable on conversion of convertible debentures, resulting in diluted weighted average trust units of 75,969,942 under this calculation.

<sup>(4)</sup> "Payout ratio" refers to distributions measured as a percentage of cash flow from operating activities including the change in non-cash working capital balances. Previously, until the second quarter ended June 30, 2006, the Trust had calculated the payout ratio as distributions divided by cash flow from operations, which excludes the change in non-cash working capital balances. This change in calculation of the payout ratio is consistent with recent staff notices provided by the Canadian Securities Administrators in respect of income trusts.

<sup>(5)</sup> DRIP refers to distributions reinvested pursuant to the Premium Distribution™ Reinvestment, Distribution Reinvestment and Optional Trust Unit Purchase Plan.

## REPORT TO UNITHOLDERS

The first quarter of 2007 marks the execution of an active and very successful drilling program. Accomplishments for the first quarter ended March 31, 2007 include:

### Distributions

In the first quarter of 2007, monthly distributions of \$0.12 per unit were declared and paid on February 15, 2007 and March 15, 2007. Following the results of True's Special and Annual Meeting, the Board has announced it has set a distribution policy for the second quarter of 2007 at a monthly rate of \$0.08 per unit, subject to monthly confirmation, based on current commodity prices, hedging program, production volumes and market conditions. This go-forward strategy for the distribution level is consistent with providing a balance between providing income to unitholders and funding for True's capital program required to further develop its land base.

### Production

2007 first quarter production averaged 18,461 boe/d as compared to 11,672 boe/d for the same period in 2006, representing a 58% increase. Sales volumes decreased 7% from the fourth quarter 2006 volumes. This takes into account the impact of curtailment in production at the Trust's Kerrobert project during offset drilling of additional wells necessary for further implementation of the SAGD project and reduced volumes of approximately 420 boe/d at the Trust's Mantario heavy oil project due to reservoir performance. True is reviewing strategies to mitigate continued impact during the remainder of the year.

Production for the remainder of 2007, considering Q1 drilling results and further planned drilling activities and property divestitures for later in 2007, is anticipated to average approximately 18,000 - 19,000 boe/d. The decrease in production in the first quarter of 2007 reflects shut-in production at Kerrobert as facility upgrades and new steam injection wells were being drilled, which is expected to materially increase production later in the year.

### Financial

Cash flow from operations for the first quarter was \$30.0 million on gross sales of \$71.2 million compared to cash flow from operations of \$19.0 million on gross sales of \$46.4 million for the same period in 2006. The increase in cash flow for the 2007 first quarter was the result of higher production volumes offset by lower natural gas prices. True's realized natural gas prices in the 2007 first quarter averaged \$7.26/mcf compared to \$7.89/mcf for the first quarter of 2006.

The net loss for the 2007 first quarter was \$8.6 million compared to net income of \$3.3 million in first quarter of 2006. This is primarily reflective of increased cash flow from operations, offset by higher depletion, depreciation and accretion charges from recent 2006 acquisitions.

### Drilling

During the first quarter of 2007, True achieved a 97% success rate in the drilling or participation in 34 (24.0 net) wells, resulting in 16 (8.6 net) natural gas wells, 15 (12.9 net) oil wells, 2 (2.0 net) stratigraphic test oil wells and 1 (0.5 net) dry holes. True successfully participated in or drilled 20 (10.4 net) wells in Alberta, and 14 (13.1 net) wells in Saskatchewan. The focus of True's drilling program for the first quarter was on the West Central Alberta area and the further execution of True's SAGD project in the Kerrobert, Saskatchewan heavy oil area.

### Dispositions

Dispositions during the first three months of 2007 consisted of two separate oil and gas property sales involving areas outside of the Trust's core areas for future development. On March 30, 2007, True closed the sale of its Columbia/Minehead and Sylvan Lake, Alberta properties. The net proceeds received on both property sales after adjustments was an aggregate of \$18.4 million and was used to pay down debt. The properties disposed of had production of approximately 360 boe/d. True continues to evaluate further opportunities with its divestiture program.

**Liquidity**

True's net debt as at March 31, 2007 was \$289.1 million, representing \$178.4 million outstanding on the credit facility, \$78.2 million in convertible debentures (liability component) and the balance a net working capital deficiency.

The existing credit facility consists of a \$15 million demand operating facility provided by one Canadian bank and a \$210 million extendible revolving term credit facility syndicated by the Canadian chartered bank, a U.S. bank, a foreign bank and one institutional lender. As at March 31, 2007, there is approximately \$45 million available under these lending facilities.

True has continued its active commodity price risk management program. True recently entered into two new commodity price risk management contracts: 1) a oil put option with a West Texas Intermediate ("WTI") reference crude oil price floor of US\$60.00 per barrel on 2,000 barrels per day for the third quarter of 2007; and 2) an additional WTI reference crude oil costless collar with a floor price of US\$65.00 per barrel and a ceiling price of US\$75.00 per barrel on 2,000 barrels per day for the fourth quarter of 2007 and the first quarter of 2008. As of May 8, 2007, the Trust has hedged volumes of 2,200 bbls/d of crude oil and 25,000 GJ/d of natural gas for the second quarter 2007, 2,000 bbls/d of crude oil and 25,000 GJ/d of natural gas for the third quarter 2007, 2,000 bbls/d of crude oil and 11,740 GJ/d of natural gas for the fourth quarter 2007, and 2,000 bbls of crude oil for the first quarter of 2008. The Trust will continue its hedging strategies during 2007 focusing on maintaining sufficient cash flow to fund True's unitholder distributions and capital program.

**Personnel Announcements**

Further to our press release dated March 15, 2007, we announced a restructuring of our senior management team for May 2007. We are pleased to announce that effective May 14, 2007 Wayne M. Chorney will join True in the capacity of President and Chief Operating Officer, bringing with him 23 years of industry experience. I will assume the role of Chairman and remain as Chief Executive Officer of True. As well, William C. Dunn, current Chairman of True, will assume the role of Lead Independent Director of True.

In addition, as announced on April 30, 2007, we are pleased to report the appointment of Doug Baker, B.Comm, FCA and Keith E. Macdonald, CA to the Board of True. Mr. Baker and Mr. Macdonald bring significant financial and industry experience to the Board and have both been appointed to the Audit Committee. Mr. James Saunders has decided to resign from the Board effective immediately. On behalf of the Board I would like to thank Mr. Saunders for his contribution.

As a result of these changes to our senior management team and the additions to the Board, we believe True is very well positioned for the future.

Paul R. Baay  
President & CEO  
May 9, 2007

## MANAGEMENT'S DISCUSSION AND ANALYSIS

*May 9, 2007 - 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 unaudited interim consolidated financial statements and selected notes for the three months ended March 31, 2007 and 2006 and the audited consolidated financial statements and Management's Discussion and Analysis for the years ended December 31, 2006 and 2005 for the Trust. This commentary is based on information available to, and is dated, May 9, 2007. 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 equivalence (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 "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 diluted cash flow from operations or cash flow from operations per unit may not be comparable with the calculation of similar measures for other entities. Management uses cash flow from operations to analyze operating performance and leverage and considers cash 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 cash flow from operations and cash flow from operating activities can be found in the management's discussion and analysis. Cash flow from operations per unit is calculated using the diluted weighted average number of units for the period.*

*This Management's Discussion and Analysis also contains the terms "payout ratio" and "distributable cash" which are not recognized measures under Canadian GAAP. Management uses payout ratio to refer to distributions measured as a percentage of cash flow available for development and acquisition opportunities as well as overall sustainability of distributions. True calculates this measure consistent with recent staff notices provided by the Canadian Securities Administrators in respect of income trusts. Management uses distributable cash to refer to the determination of cash available for distribution to unitholders. True's method of calculating these measures may differ from other entities, and accordingly, may not be comparable to the measures used by other trusts or companies. This Management's Discussion and Analysis also contains other terms such as net debt and operating netbacks, which are not recognized measures under Canadian GAAP. 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 royalties and operating costs. 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 earnings 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](http://www.sedar.com).*

*FORWARD LOOKING STATEMENTS: Certain information contained herein may contain forward looking statements including management's assessment of future plans and operations, impact of, and timing of certain projects, effects of drilling or wells to be tied-in, the effect of government announcements, proposals and legislation, plans regarding hedging, wells to be drilled, the effect of recent legislation, expected or anticipated production rates, the weighting of production between different commodities, commodity prices, exchange rates, expected levels of royalty rates, production expenses, transportation costs and other costs and expenses, 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. The reader is cautioned not to place undue reliance on this forward looking information. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhausted. 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](http://www.sedar.com)), at True's website ([www.trueenergytrust.com](http://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.*

## Net Income (Loss) and Cash Flow from Operations

True generated cash flow from operations of \$30.0 million (\$0.42 per diluted unit) for the three months ended March 31, 2007, up 58% from the \$19.0 million (\$0.52 per diluted unit) for the first quarter of 2006. Lower commodity prices, despite increased volumes, and increased average outstanding trust units were the primary factors contributing to the decrease in cash flow per diluted unit.

True generated a net loss of \$8.6 million (\$(0.12) per diluted unit) in the first quarter of 2007 compared to net income of \$3.3 million (\$0.09 per diluted unit) in 2006. Net loss per unit in the first quarter of 2007 was impacted primarily as a result of an increase in cash flow from operations, offset by higher depletion, depreciation and accretion charges from the Q2 and Q3 2006 acquisitions of Shellbridge Oil & Gas, Inc. ("Shellbridge") and Prairie Schooner Petroleum Ltd. ("Prairie Schooner"), respectively, and the associated higher production volumes.

### Cash Flow From Operations and Net Income

(\$000s, except per unit amounts)	Three months ended March 31,	
	2007	2006
Cash flow from operations	29,988	18,995
Basic (\$/unit)	0.43	0.52
Diluted (\$/unit)	0.42	0.52
Net income (loss)	(8,571)	3,259
Basic (\$/unit)	(0.12)	0.09
Diluted (\$/unit)	(0.12)	0.09

### Reconciliation of Cash Flow from Operations and Distributions

Distributable cash is determined by aggregating various amounts received, including interest income on notes of subsidiaries and other interest income received or receivable, income generated under net profits interest, royalty, other permitted investments and dividends and other distributions on securities of subsidiaries, after deduction of all expenses and liabilities of the Trust. The portion of distributable cash declared payable to unitholders on any distribution date is determined on recommendation of the Board of Directors of True Energy Inc., as administrator of the Trust.

### Reconciliation of Cash Flow from Operations and Distributions

(\$000s, except per unit amounts)	Three months ended March 31,	
	2007	2006
Cash flow from operations	29,988	18,995
Change in non-cash working capital	18,227	(8,386)
Cash flow from operating activities	48,215	10,609
Funding from long-term debt and DRIP	-	15,541
Cash withheld to fund capital and other expenditures	(31,349)	-
Distributions paid	16,866	26,150
Accumulated distributions, beginning of period	141,716	17,361
Accumulated distributions, end of period	158,582	43,511
Distributions per unit for outstanding units in the period	0.24	0.72
Accumulated distributions per unit, beginning of year	3.12	0.48
Accumulated distributions per unit, end of year	3.36	1.20

The Premium Distribution™ Reinvestment, Distribution Reinvestment and Optional Trust Unit Purchase Plan ("DRIP") was implemented effective March 27, 2006. Funds reinvested in the Trust through this plan were available to fund capital and other expenditures. On November 16, 2006, the Trust announced the suspension of equity available for reinvestment under DRIP until further notice.

### **Payout Ratio**

<i>(\$000s, except percentages)</i>	Three months ended March 31,	
	2007	2006
Cash flow from operations	29,988	18,995
Change in non-cash working capital	18,227	(8,386)
Cash flow from operating activities	48,215	10,609
Distributions paid before DRIP	16,866	26,150
DRIP	-	(1,317)
Distributions after DRIP	16,866	24,833
Payout ratio before DRIP	35%	246%
Payout ratio after DRIP	35%	234%

Payout ratio refers to distributions measured as a percentage of cash flow from operating activities including the change in non-cash working capital balances. Previously, until the second quarter ended June 30, 2006, the Trust had calculated the payout ratio as distributions divided by cash flow from operations, which excludes the change in non-cash working capital balances. This change in calculation of the payout ratio is consistent with recent staff notices provided by the Canadian Securities Administrators in respect of income trusts.

### **Sales Volumes**

Sales volumes for the first three months of 2007 averaged 18,461 boe/d, an increase of 58% compared to 11,672 boe/d reported in 2006. This increase was due to a combination of results from drilling activity and the acquisitions of Shellbridge effective June 23, 2006 and Prairie Schooner effective September 22, 2006. Production for the first quarter of 2007 is down by 7% from average sales volumes of 19,747 boe/d during the fourth quarter of 2006. The decrease from fourth quarter volumes was a result of the impact of curtailment in production at the Trust's Kerrobert project during offset drilling of additional wells necessary for further implementation of the steam assisted gravity drainage ("SAGD") project and reduced volumes of approximately 420 boe per day at the Trust's Mantario heavy oil project due to reservoir performance. True is reviewing strategies to mitigate continued impact during the remainder of the year. At the end of the first quarter, 17 wells were awaiting down-hole completion and/or completion of production facilities. Work is ongoing in the second quarter as ground and weather conditions permit. True's significant drilling activity in the first quarter of 2007 is expected to contribute to production primarily in the third and fourth quarters of 2007.

For the three month period ended March 31, 2007, the weighting towards natural gas production averaged 65% compared to 61% in the same period in 2006. Heavy oil sales made up 24% of total production for the first quarter of 2007 compared to 22% in the same period in 2006. The increase in heavy oil weighting from the first quarter of 2006 to that in 2007 was due to the addition of primarily heavy oil weighted assets from Shellbridge at the end of the second quarter of 2006, offset by certain shut-in heavy oil production at Kerrobert during the first quarter of 2007. The September 2006 acquisition of Prairie Schooner added significant natural gas volumes which has increased the natural gas production

weighting. Currently, the Trust estimates that the weighting towards natural gas production is approximately 64%.

### Sales Volumes

		Three months ended March 31,	
		2007	2006
Natural gas	(mcf/d)	71,931	42,992
Heavy oil	(bbls/d)	4,355	2,571
Light oil and condensate	(bbls/d)	1,519	1,653
NGLs	(bbls/d)	598	283
Total crude oil and NGLs	(bbls/d)	6,472	4,507
Total boe/d	(6:1)	18,461	11,672

Sales of natural gas averaged 71.9 mmcf/d for the first three months of 2007, compared to 43.0 mmcf/d in 2006, an increase of 67%. In comparison, natural gas volumes averaged 73.8 mmcf/d for the fourth quarter of 2006.

Crude oil and NGL sales for the first three months of 2007 averaged 6,472 bbls/d up 44% from average sales of 4,507 bbls/d in 2006. Most of this increase was due to greater oil volumes from the acquisition of Shellbridge in June 2006 and an increased drilling program in 2006 and 2007. In comparison, crude oil and NGL sales for the fourth quarter of 2006 were 7,440 bbls/d; the decrease from the fourth quarter of 2006 to the first quarter of 2007 is due to a reduction in heavy oil volumes.

## Commodity Prices

The impact of changes in the Canadian dollar from the conversion of US dollar based commodities prices marginally reduced profitability during the first three months of 2007 when compared to the same period in 2006. The U.S./Canadian exchange rate changed 1% from an average of 0.8662 in 2006 to 0.8535 in 2007.

### Average Commodity Prices

	Three months ended March 31,		
	2007	2006	% change
Exchange rate (US\$/Cdn\$)	0.8535	0.8662	(1)
Natural gas:			
NYMEX (US\$/mmbtu)	7.17	7.84	(9)
Alberta spot (\$/mcf)	7.00	7.34	(5)
True's average price (\$/mcf)	7.26	7.89	(8)
True's average price (including hedging) (\$/mcf)	7.15	7.89	(9)
Crude oil:			
WTI (US\$/bbl)	58.27	63.34	(8)
Edmonton par – light oil (\$/bbl)	67.73	69.27	(2)
Bow River – medium/heavy oil (\$/bbl)	49.73	40.19	24
Hardisty Heavy – heavy oil (\$/bbl)	42.50	30.54	39
True's average prices (\$/bbl)			
Light crude and condensate	55.48	58.32	(5)
Light crude and condensate (including hedging)	65.39	58.32	12
NGLs	38.83	50.25	(23)
Light crude oil, condensate and NGLs	50.77	57.14	(11)
Light crude oil, condensate and NGLs (including hedging)	57.88	57.14	1
Heavy crude oil	36.64	25.84	42
Total crude oil and NGLs	41.26	39.28	5
Total crude oil and NGLs (including hedging)	43.59	39.28	11

True's natural gas is primarily sold on the daily spot market. During first three months of 2007, the Alberta Spot reference price decreased by 5% compared to the same period in 2006. Similarly, True's average sales price before transportation and hedging for the first three months of 2007 averaged \$7.26/mcf for its natural gas, 8% less than the \$7.89/mcf received in 2006. In comparison, True's average sales price for natural gas averaged \$6.98/mcf for the fourth quarter of 2006.

For heavy crude oil, True received an average price before transportation of \$36.64/bbl during the first quarter of 2007, an increase of 42% over 2006 prices. The Bow River and Hardisty Heavy reference prices increased by 24% and 39%, respectively. The majority of True's heavy crude oil density ranges between 11 and 16 degrees API consistent with the Hardisty Heavy reference price. The price differential of heavy oil reference crude compared to light oil has improved since last fall. In comparison, True received an average heavy oil price of \$34.82/bbl for the fourth quarter of 2006.

For light oil, condensate and NGLs, True recorded an average \$50.77/bbl before hedging during the first quarter of 2007, 11% lower than the average price received in 2006 due to a higher proportion of heavy crude oil. During this same period, the Edmonton par price increased by 2%. In comparison, True received an average oil price for light oil, condensate and NGLs of \$60.34/bbl in the fourth quarter of 2006. True's realized price decreased 16% from the fourth quarter of 2006 to the first quarter of 2007, whereas the Edmonton par price increased by 4% over the same period. The primary reason for this

difference is a 22% decrease in True's average price received for NGLs over this period due to a current quarter adjustment of fourth quarter 2006 price estimates.

## Revenue

Revenue before other income and transportation for the three months ended March 31, 2007 was \$71.0 million, 53% greater than the \$46.4 million in the same period of 2006. The higher revenue was the result of significant growth in production volumes for natural gas, crude oil, condensate and NGLs, despite lower overall crude oil and natural gas prices.

(\$000s)	Three months ended March 31,	
	2007	2006
Light crude oil and condensate	7,584	8,675
NGLs	2,091	1,278
Heavy oil	14,362	5,977
Crude oil and NGLs	24,037	15,930
Natural gas	46,982	30,514
Total revenue before other	71,019	46,444
Other	177	(48)
Total revenue before royalties and hedging	71,196	46,396
Gain (loss) on commodity contracts	679	-
Total revenue before royalties	71,875	46,396

## Financial Instruments

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, costless collars and the purchase of floor price options and other derivative financial instruments 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 cash distributions, as well as, to ensure True realizes positive economic returns from its capital developments and acquisition activities.

As of May 8, 2007, the Trust has hedged volumes of 2,200 bbls/d of crude oil and 25,000 GJ/d of natural gas for the second quarter 2007, 2,000 bbls/d of crude oil and 25,000 GJ/d of natural gas for the third quarter 2007, 2,000 bbls/d of crude oil and 11,740 GJ/d of natural gas for the fourth quarter 2007, and 2,000 bbls of crude oil for the first quarter of 2008. The Trust will continue its hedging strategies during 2007 focusing on maintaining sufficient cash flow to fund True's unitholder distributions and capital program.

A summary of the hedge volumes and average prices by quarter currently outstanding is shown in the following tables (see Note 18 to the consolidated financial statements for a detailed disclosure of all commodity contracts in place as at May 8, 2007):

<b>Crude oil and liquids</b>	<b>Average Volumes (bbls/d)</b>			
	Q2 2007	Q3 2007	Q4 2007	Q1 2008
Costless collars	-	-	2,000	2,000
Put option (price floor)	2,200	2,000	-	-
<b>Total bbls/d</b>	<b>2,200</b>	<b>2,000</b>	<b>2,000</b>	<b>2,000</b>

<b>Average Price (US\$/bbl WTI)</b>				
	Q2 2007	Q3 2007	Q4 2007	Q1 2008
Collar ceiling price	-	-	75.00	75.00
Collar floor price	-	-	65.00	65.00
Put option price floor	64.55	60.00	-	-

<b>Natural gas</b>	<b>Average Volumes (GJ/d)</b>			
	Q2 2007	Q3 2007	Q4 2007	Q1 2008
Costless collars	15,000	15,000	5,050	-
Fixed	10,000	10,000	6,690	-
<b>Total GJ/d</b>	<b>25,000</b>	<b>25,000</b>	<b>11,740</b>	<b>-</b>

<b>Average Price (\$/GJ AECO C)</b>				
	Q2 2007	Q3 2007	Q4 2007	Q1 2008
Collar ceiling price	9.29	9.29	9.29	-
Collar floor price	7.00	7.00	7.00	-
Fixed	7.05	7.05	7.03	-

The following is a summary of the gain (loss) on commodity contracts for the three months ended March 31, 2007:

<b>Commodity contracts</b>				
<i>(\$000s)</i>	Crude Oil & Liquids	Natural Gas	2007 Total	2006 Total
Realized cash gain (loss) on contracts <sup>(1)</sup>	1,447	1,697	3,144	-
Unrealized gain (loss) on contracts	(92)	(2,373)	(2,465)	-
<b>Total gain (loss) on commodity contracts</b>	<b>1,355</b>	<b>(676)</b>	<b>679</b>	<b>-</b>

<sup>(1)</sup> Includes the amortization of crude oil and natural gas commodity contract premiums of \$0.8 million and \$1.6 million, respectively, for the three month period ended March 31, 2007.

Effective January 1, 2007, new accounting standards were implemented relating to financial instruments. The impacts of adopting the new standards are reflected in the Trust's current quarter results, and prior year comparative financial statements have not been restated. For a description of the new accounting standards and the impact on the Trust's financial statements of adopting such rules, including the impact on the Trust's prepaid expenses, deferred financing charges, long-term debt, convertible debentures and unrealized gains on commodity contracts, refer to note 3 of the unaudited interim consolidated financial statements of the Trust for the three months ended March 31, 2007.

## **Royalties**

For the three months ending March 31, 2007, total royalties were \$14.9 million, compared to \$10.6 million incurred in the same period in 2006 up 40%, which was slightly less than the 53% increase in total

revenue for the period. Overall royalties as a percentage of revenue (after transportation costs) in the first quarter of 2007 was 21%, compared with 23% in the same period in 2006. The average royalty rate of 21% for the quarter includes the impact of the reversal of certain overaccruals of light and heavy crude oil royalties from prior periods of approximately \$1.9 million. Excluding this adjustment, the average royalty rate for the first quarter of 2007 would be approximately 24%. This is consistent with the 25% average total royalty rate for the fourth quarter of 2006.

<b>Royalties by Commodity Type</b> <i>(\$000s, except where noted)</i>	Three months ended March 31,	
	2007	2006
Light crude oil and condensate	251	1,518
\$/bbl	1.84	10.20
Average light crude oil and condensate royalty rate (%)	3	18
NGLs	630	309
\$/bbl	11.70	12.15
Average NGLs royalty rate (%)	30	24
Heavy Oil	1,519	1,099
\$/bbl	3.88	4.53
Average heavy oil royalty rate (%)	11	20
Natural Gas	12,494	7,715
\$/mcf	1.93	1.99
Average natural gas royalty rate (%)	27	26
<b>Total</b>	<b>14,894</b>	<b>10,641</b>
\$/boe	8.96	10.13
Average total royalty rate (%)	21	23

### **Royalties, by Type**

<i>(\$000s)</i>	Three months ended March 31,	
	2007	2006
Crown royalties, net of ARTC	6,203	7,135
Indian Oil and Gas Canada royalties	3,142	782
Freehold & GORR	5,549	2,724
<b>Total</b>	<b>14,894</b>	<b>10,641</b>

### **Expenses**

<i>(\$000s)</i>	Three months ended March 31,	
	2007	2006
Production	14,972	9,167
Transportation	689	973
General and administrative	4,904	2,597
Interest and financing charges	4,547	1,763
Unit-based compensation	1,112	1,410

### **Expenses per boe**

<i>(\$ per boe)</i>	Three months ended March 31,	
	2007	2006
Production	9.01	8.73
Transportation	0.41	0.93
General and administrative	2.95	2.47
Interest and financing charges	2.74	1.68
Unit-based compensation	0.67	1.34

## Production Expenses

For the three months ended March 31, 2007, production expenses totaled \$15.0 million, compared to \$9.2 million recorded in 2006. During the first quarter of 2007, production expenses averaged \$9.01/boe, an increase of 3% over the same period in 2006. This increase in production expenses is largely due to a different property mix along with inflationary pressure on the costs of services. True is forecasting production expenses to average \$9.00/boe in 2007.

### Production Expenses, by Commodity Type

(\$000s, except where noted)	Three months ended March 31,	
	2007	2006
Light crude oil and condensate	2,335	1,866
\$/bbl	17.08	12.54
NGLs	182	230
\$/bbl	3.38	9.05
Heavy oil	5,405	1,927
\$/bbl	13.79	8.33
Natural gas	7,050	5,144
\$/mcf	1.09	1.33
Total	14,972	9,167
\$/boe	9.01	8.73

## Transportation

Transportation costs are expected to be approximately 2% to 3% of gross revenues for the 2007 year. For the three months ended March 31, 2007, transportation costs averaged less than 1% due to the impact of the reversal of overaccruals of certain product transportation estimates of \$1.0 million from prior periods.

## Operating Netback

For the three months ended March 31, 2007, corporate field operating netback (before hedging) was \$24.36/boe compared to \$24.43/boe in 2006. Decreased commodity prices were offset by primarily reduced average royalties due to prior period crude oil royalty adjustments. By comparison, corporate field operating netback (before hedging) for the fourth quarter of 2006 was \$21.05/boe. After including hedging activities, corporate field operating netback for the first quarter was \$24.76/boe compared to \$24.43/boe in 2006.

### Field Operating Netback – Corporate (before hedging)

(\$/boe)	Three months ended March 31,	
	2007	2006
Sales	42.74	44.22
Transportation	(0.41)	(0.93)
Royalties	(8.96)	(10.13)
Production expense	(9.01)	(8.73)
Field operating netback	24.36	24.43

Field operating netback for natural gas for the three months ended March 31, 2007 decreased 8% to \$4.09/mcf, compared to \$4.44/mcf for 2006, reflecting the weaker natural gas prices experienced. After

including hedging activities, field operating netback for natural gas for the first quarter of 2007 was \$3.98/mcf compared to \$4.44/mcf in 2006.

#### **Field Operating Netback - Natural Gas (before hedging)**

<i>(\$/mcf)</i>	Three months ended March 31,	
	2007	2006
Sales	7.26	7.89
Transportation	(0.15)	(0.13)
Royalties	(1.93)	(1.99)
Production expense	(1.09)	(1.33)
Field operating netback	4.09	4.44

Field operating netback for crude oil and NGLs averaged \$24.06/bbl for the three months ended March 31, 2007, up 15% compared to \$20.95/bbl for 2006, compared to an 5% increase in the crude oil and NGLs sales price. Prior period adjustments recorded in the quarter for transportation and royalties contributed primarily to a temporary increase in field operating netback for crude oil and NGLs. After including hedging activities, field operating netback for crude oil and NGLs was \$26.39/boe compared to \$20.95/boe in 2006.

#### **Field Operating Netback - Crude Oil and NGLs (before hedging)**

<i>(\$/bbl)</i>	Three months ended March 31,	
	2007	2006
Sales	41.26	39.28
Transportation	0.52	(1.19)
Royalties	(4.12)	(7.22)
Production expense	(13.60)	(9.92)
Field operating netback	24.06	20.95

### **General and Administrative**

Net general and administrative expenses for the three months ended March 31, 2007 were \$4.9 million compared to \$2.6 million for the same period in 2006. On a per-unit of production basis, general and administrative expenses ("G&A") in the first quarter of 2007 is \$2.95/boe, compared to \$2.47/boe in 2006.

The increase in the G&A on a per boe basis from the first quarter of 2006 to the same period in 2007 is consistent with the increase in staffing levels, higher compensation and other administrative costs as a result of two acquisitions completed in 2006.

#### **General and Administrative Expenses**

<i>(\$000s, except where noted)</i>	Three months ended March 31,	
	2007	2006
Gross expenses	6,410	3,813
Capitalized	(693)	(536)
Recoveries	(813)	(680)
Net expenses	4,904	2,597
Net expenses, per unit (\$/boe)	2.95	2.47

G&A expenses for the three month period ended March 31, 2007 do not include the costs of the March 30, 2007 Special Meeting, which are presented separately on the Statement of Income and discussed in the Special Meeting Costs section of this report.

## Interest and Financing Charges

True recorded \$4.5 million of interest and financing charges the three months ended March 31, 2007 compared to \$1.8 million in the same period of 2006. The increase in interest and financing charges for the 2007 first quarter compared to the same period in 2006 is consistent with the increase in bank debt and convertible debentures. True's net debt at March 31, 2007 of \$289.1 million includes the \$78.2 million liability portion of convertible debentures, \$178.4 million of bank debt and the balance a working capital deficiency.

### Interest and Financing Charges

(\$000s, except where noted)	Three months ended March 31,	
	2007	2006
Interest and financing charges	4,547	1,763
Interest and financing charges (\$/boe)	2.74	1.68
Net debt including convertible debentures at quarter end	289,072	139,611
Debt to periods cash flow from operations ratio annualized	2.4x	1.8x
Net debt excluding convertible debentures at quarter end	210,829	139,611
Debt to periods cash flow from operations ratio annualized	1.8x	1.8x

## Unit-Based Compensation

Non-cash unit-based compensation expense for the three months ended March 31, 2007 was \$1.1 million compared to \$1.4 million in 2006. The slight decrease in the 2007 expense reflects no further new incentive rights being granted since 2006 and only the charge to income in the period in relation to pre-2007 grants.

## Capital Expenditures

True invested \$45.8 million on exploration and development activities during the first three months of 2007, compared to \$22.5 million in the same period in 2006. During the first quarter of 2007, True achieved a 97% success rate in the drilling or participation in 34 (24.0 net) wells, resulting in 16 (8.6 net) natural gas wells, 15 (12.9 net) oil wells, 2 (2.0 net) stratigraphic test oil wells and 1 (0.5 net) dry holes. True successfully participated in or drilled 19 (10.4 net) wells in Alberta, and 14 (13.1 net) wells in Saskatchewan. The focus of True's drilling program for the first quarter was on the West Central Alberta area and the further execution of True's SAGD project in the Kerrobert, Saskatchewan heavy oil area.

### Capital Expenditures

(\$000s)	Three months ended March 31,	
	2007	2006
Lease acquisitions and retention	791	1,875
Geological and geophysical	6,919	664
Drilling and completion costs	33,259	17,285
Facilities and equipment	4,872	2,637
Exploration and development	45,841	22,461
Corporate and property acquisitions	705	124
Total capital expenditures – cash	46,546	22,585
Property dispositions – cash	(18,443)	-
Total net capital expenditures – cash	28,103	22,585
Other – non-cash <sup>(1)</sup>	624	635
Total capital expenditures	28,727	23,220

<sup>(1)</sup> Other includes current period's asset retirement obligations and unit based compensation capitalized.

True holds an extensive land base. At March 31, 2007, True has approximately 696,000 net undeveloped acres of land of its total developed and undeveloped net acreage position of 1,115,000 net acres in Saskatchewan, Alberta, and British Columbia.

Dispositions during the first three months of 2007 consist of two separate oil and gas property sales involving areas outside of the Trust's core areas for future development. On March 30, 2007, True closed the sale of its Columbia/Minehead and Sylvan Lake, Alberta properties. The net proceeds received on both property sales after adjustments was an aggregate of \$18.4 million.

At the end of the first quarter of 2007, True had no formal drilling commitments. True expects to be making further drilling commitments during the latter part of 2007 to carry out the remainder of its 2007 capital program.

## Depletion, Depreciation and Accretion

Depletion, depreciation and accretion (site restoration) expense for the first three months of 2007 was \$47.5 million, compared to the \$29.2 million for the same period in 2006, reflecting the acquisition of Shellbridge in June 2006, Prairie Schooner in September 2006 in conjunction with increased production volumes and True's active drilling program over 2006 and 2007. True's DD&A rate for the first quarter of 2007 of \$28.56/boe was lower than \$29.21/boe DD&A rate for the fourth quarter of 2006, which reflects the adjustment after a fourth quarter 2006 ceiling test impairment was recorded.

For the three month period ended March 31, 2007, True has excluded from the depletion calculation \$46.9 million for undeveloped land and \$48.7 million for estimated salvage.

### Depletion, Depreciation and Accretion Costs

(\$000s, except where noted)	Three months ended March 31,	
	2007	2006
Depletion	45,636	25,163
Depreciation	1,311	3,837
Accretion	511	212
Total	47,458	29,212
Per unit (\$/boe)	28.56	27.81

The Trust's independent reserve report effective December 31, 2006 is summarized in its Annual Information Form and can be found at [www.sedar.com](http://www.sedar.com).

## Ceiling Test

The Trust calculates a ceiling test quarterly and annually whereby the carrying value of petroleum and natural gas properties is compared to estimated future cash flow from the production of proved reserves. 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 March 31, 2007 resulting in undiscounted cash flows from proved reserves and the unproved 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 unproved 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.

At March 31, 2007, the Trust calculated the ceiling test using prices of \$40.51/bbl for heavy oil, \$67.89/bbl for light and medium gravity oil, and \$47.33/bbl for NGLs, and \$8.33/mcf for natural gas.

## **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 will 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 plan of arrangement was not approved.

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

## **Asset Retirement Obligation**

As at March 31, 2007, the Trust has recorded an Asset Retirement Obligation ("ARO") of \$26.4 million, compared to \$10.9 million at March 31, 2006, for future abandonment and reclamation of the Trust's properties. For the three month period ended March 31, 2007, the ARO decreased by \$0.2 million total as a result of accretion expense of \$0.5 million, \$0.8 million of liabilities released on dispositions and included \$0.1 million net changes in estimates and development activities.

## **Income Taxes**

For the first three months of 2007, the Trust has recorded a provision for capital taxes of \$0.9 million compared to \$0.6 million expensed in the same period in 2006. 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 provincial taxes calculated as a percentage of revenues. Increased gross sales revenue from Saskatchewan based properties is the reason for the quarter over quarter increase in capital taxes. In the second quarter of 2006, the federal government enacted legislation that eliminates federal capital tax, retroactive to January 1, 2006. As a result, capital taxes on a go-forward basis are based on only provincial capital taxes.

Future income taxes arise from differences between the accounting and tax bases of the operating companies' assets and liabilities. For the first three months of 2007, the Trust recognized a future income tax recovery provision of \$12.8 million compared to a recovery provision of \$13.2 million in the same period in 2006. On April 10, 2006 the Alberta government enacted a decrease of 1.5 percent to the provincial corporate tax rate. In addition, on June 6, 2006 the Federal government enacted a two percent decrease to the federal corporate tax rate from January 1, 2008 to January 1, 2010 and an elimination of the 1.12 percent federal surtax at January 1, 2008.

In the Trust's structure, payments are made between the operating subsidiaries and the Trust transferring income and future income tax liability to the unitholders. Therefore, it is currently expected, based on existing legislation, that no cash income taxes are to be paid by the operating subsidiaries. As such, the future income tax liability recorded on the balance sheet will be recovered through earnings over time. As at March 31, 2007, the operating subsidiaries have a future income tax liability balance of \$111.4 million. Canadian GAAP requires that a future income tax liability be recorded when the book value of assets exceeds the balance of tax pools. It further requires that a future tax liability be recorded on an acquisition when a corporation acquires assets with associated tax pools that are less than the purchase price.

At March 31, 2007 the Trust and operating subsidiaries of the Trust had approximately \$522 million, net of partnership deferrals, in tax pools available for deduction against future income as follows:

<i>(\$000s)</i>	Trust	Operating subsidiaries	Total
Intangible resource pools (net of partnership deferrals)	15,105	334,445	349,550
Undepreciated capital cost	-	150,768	150,768
Loss carryforwards (expire through 2026)	-	6,256	6,256
Unit issue costs	8,931	6,228	15,159
Other	-	243	243
	<b>24,036</b>	<b>497,940</b>	<b>521,976</b>

The October 31, 2006 announcement of the Tax Fairness Plan by the Federal Government anticipates a distribution tax on distributions from publicly traded income trusts and similar structures. For existing income trusts and similar structures, the government is proposing a four-year transition period. 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. Refer to “Business Risks and Uncertainties” of the Trust’s 2006 MD&A for further details.

As at March 31, 2007, and until third reading of the Bill in Parliament, current and future income taxes have not been adjusted as a result of this announcement. If implemented as currently proposed, the Trust would be required to recognize in its accounts, in the period in which the change is substantively enacted, future income taxes on temporary differences in the Trust.

## Distributions

Trust unitholders who held their trust units throughout the first quarter of 2007 received distributions of \$0.24 per unit. For the three months ended March 31, 2007 the Trust declared \$16.9 million in total distributions as follows:

<i>(\$000s, except per unit amount)</i>	Distribution Per Unit	Total
Three months ended March 31, 2007		
Distributions paid	\$ 0.24	\$ 16,866

### Distribution Paid History <sup>(1)</sup>

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](http://www.trueenergytrust.com).

Calendar Year	Distributions per unit	Taxable Portion	Return of Capital
2005 (two months) <sup>(2)</sup>	\$ 0.480	\$ 0.456	\$ 0.024
2006 <sup>(3)</sup>	2.640	2.033	0.607
Cumulative to Dec. 31, 2006	3.120	2.489	0.631
2007 year to date	0.240	<sup>(3)</sup>	<sup>(3)</sup>
Cumulative to March 31, 2007	3.360		

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

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

<sup>(3)</sup> A portion of the distributions paid in 2007 to Canadian unitholders will be taxable. U.S. unitholders will also be taxable. 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 experienced throughout the year. The approximate taxable portion of 2007 distributions to Canadian unitholders is currently estimated to be between 90 to 100%.

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 2007 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 view our March 7, 2007 press release addressing this.

## Monthly Distributions

Actual distributions paid and declared per Trust unit along with relevant payment dates for 2007 to date are as follows:

Ex-distribution Date	Record Date	Payment Date	Distribution per unit
December 27, 2006	December 31, 2006	January 15, 2007	\$ 0.12
January 29, 2007	January 31, 2007	February 15, 2007	0.12
February 26, 2007	February 28, 2007	March 15, 2007	0.12
April 26, 2007	April 30, 2007	May 15, 2007	0.08
May 29, 2007 <sup>(1)</sup>	May 31, 2007	June 15, 2007	0.08 <sup>(2)</sup>
June 27, 2007 <sup>(1)</sup>	June 29, 2007	July 16, 2007	0.08 <sup>(2)</sup>

<sup>(1)</sup> Anticipated ex-distribution dates for May and June. These dates are subject to change and/or confirmation by the Toronto Stock Exchange and will be confirmed by monthly press release.

<sup>(2)</sup> Subject to confirmation, the Management and Board of the Trust continuously assesses distribution levels, in light of current commodity prices, hedge positions, production volumes, market conditions and other factors, and announces the distribution per unit amount on a monthly basis.

During the first three months of 2007, the distributions were funded directly from cash flows from operating activities.

The Trust declared and paid distributions of \$0.12 per unit on February 15, 2007 and March 15, 2007. On January 15, 2007, the Trust announced its intention to convert to a growth oriented, dividend paying intermediate exploration and production company (the "Reorganization"), which was voted upon by securityholders at an Annual and Special Meeting (the "Meeting") held on March 30, 2007. Further as announced on February 15, 2007, the Board of True determined that no distribution would be declared for the month of March 2007, which would normally have been paid on April 16, 2007 to unitholders of record as at March 30, 2007, pending the consideration of the Reorganization at the Meeting.

As a result of the outcome of the Meeting, wherein the Reorganization was not approved, True remains a trust. The Board of True reviewed the go-forward strategy for the distribution level to provide a balance between providing income to unitholders and budgeting for capital expenditures required to further develop the Trust's land base. In a press release dated April 17, 2007, the Board announced it has set a distribution policy for the second quarter of 2007 at a monthly rate of \$0.08 per unit, subject to monthly confirmation, based on current commodity prices, hedging program, production volumes, and market conditions.

## Foreign Ownership Update

Based on information from Trust records and information provided by intermediaries holding Trust units for others, we estimate that, as of April 20, 2007 approximately 29 percent of our Unitholders are non-Canadian residents with the remaining 71 percent being Canadian residents. True's Trust Indenture provides that not more than 40 percent of its trust units can be held by non-Canadian residents.

## Liquidity and Capital Resources

True's net debt as at March 31, 2007 was \$289.1 million, representing \$178.4 million outstanding on the credit facility, \$78.2 million in convertible debentures (liability component) and the balance a net working capital deficiency.

The current credit facility consists of a \$15 million demand operating facility provided by one Canadian bank and a \$210 million extendible revolving term credit facility syndicated by the Canadian chartered bank, a U.S. bank, a foreign bank and one institutional lender. The revolving period on the revolving term credit facility ends on June 29, 2007, 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. Further details of the revised credit facility are disclosed in note 7 of the consolidated financial statements. As at March 31, 2007, there is approximately \$45 million available under these lending facilities.

Management expects to be able to fund the \$80 million capital expenditure program for 2007 using cash flow from operations, available credit facilities, the proceeds from the expected sale of certain non-core assets, and the maintenance of sustainable distributions. If cash flows are other than projected, capital expenditure levels will be adjusted. The practice of continually monitoring spending opportunities in comparison to expected cash flow levels allows for adjustments to the capital program as required.

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.

As at April 30, 2007 the Trust had outstanding a total of 5,342,166 incentive units exercisable at an average exercise price of \$13.51 per unit, 401,964 exchangeable shares (convertible, as at April 30, 2007 into an aggregate of 303,547 trust units, subject to further adjustments based on distributions made on trust units) and 70,276,890 trust units.

On February 13, 2007, True announced it had identified certain small, non-core properties, for possible disposition. The proceeds will be used to fund capital expenditures and pay down debt. The Trust closed on two dispositions at the end of the first quarter and is continuing to evaluate opportunities under its divestiture program.

## **Business Prospects and 2007 Outlook**

Since its formation in September 2000, True Energy Inc. has experienced significant growth in its production and land base. 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.

Following the results of the Special and Annual Meeting held on March 30, 2007, True remains a trust. Therefore, the focus will continue to be maintaining sufficient cash flow to provide a balance between unitholder distributions and funding of the Trust's capital program.

Late in September 2006, the Trust completed the purchase of a facility in the Kerrobert, Saskatchewan area and wells which has allowed the Trust to begin implementation of the steam assisted gravity drainage ("SAGD") phase of the project. Continuing through June 2007, the Trust plans to convert a number of existing wells to steam injectors and drill additional wells that will be used as producing well bores. During the first quarter of 2007, True completed its initial drilling campaign of five cold producers and four thermal wells. All five cold producers are on-line, currently averaging 95 bbls/d per well. The four thermal wells are cased and awaiting equipping prior to the conversion and subsequent steaming of the paired injectors. Execution of the SAGD project is on track with expected steam injection for phase one to commence at the end of the third quarter. Capital expenditure levels will be adjusted as appropriate. The Trust currently anticipates spending approximately \$80 million in total capital spending for 2007. The remainder of the 2007 capital program will emphasize True's core areas of West Central Alberta and West Central Saskatchewan. These expenditures will be mainly in the third quarter, following up on successful development campaigns in the first quarter. It will include facility modifications and conversion of existing producers to steam injection service at the Kerrobert SAGD project. Continued participation in what has been a highly successful non-operated drilling program in West Central Alberta will also carry on in the third quarter.

The Trust currently anticipates that 2007 year average production will be approximately 18,000 to 19,000 boe/d, weighted approximately 64% toward natural gas. True further anticipates the US\$/Cdn.\$ exchange rate to average 0.90 through the 2007 year.

The Trust continues to maintain a large undeveloped land base of approximately 1.0 million (0.7 million net) acres and has identified a multi-year drilling inventory of over 600 net locations.

## **Business Risks and Uncertainties**

The reader is advised that True continues to be subject to various types of business risks and uncertainties as described in the Management Discussion and Analysis in the Trust's December 31, 2006 Annual Report and the Trust's Annual Information Form. In addition, the Trust is also subject to the following business risks and uncertainties:

### **Environmental Regulation and Risk**

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. In 2002, the Government of Canada ratified the Kyoto Protocol (the "Protocol"), which calls for Canada to reduce its greenhouse gas emissions to

specified levels. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Protocol or as otherwise determined could have a material impact on the nature of oil and natural gas operations, including those of the Trust.

The Federal Government released on April 26, 2007, its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan"), also known as ecoACTION and 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. Regarding large industry and industry related projects the Government's Action Plan intends to achieve the following: (i) an absolute reduction of 150 megatonnes in greenhouse gas emissions by 2020 by imposing mandatory targets; and (ii) air pollution from industry is to be cut in half by 2015 by setting certain targets. New facilities using cleaner fuels and technologies will have a grace period of three years. In order to facilitate the companies' compliance of the Action Plan's requirements, while at the same time allowing them to be cost-effective, innovative and adopt cleaner technologies, certain options are provided. These are: (i) in-house reductions; (ii) contributions to technology funds; (iii) trading of emissions with below-target emission companies; (iv) offsets; and (v) access to Kyoto's Clean Development Mechanism.

On March 8, 2007, the Alberta Government introduced Bill 3, the Climate Change and Emissions Management Amendment Act, which intends to reduce greenhouse gas emission intensity from large industries. Bill 3 states that facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12% starting July 1, 2007; if such reduction is not initially possible the companies owning the large emitting facilities will be required to pay \$15 per tonne for every tonne above the 12% target. These payments will be deposited into an Alberta-based technology fund that will be used to develop infrastructure to reduce emissions or to support research into innovative climate change solutions. As an alternate option, large emitters can invest in projects outside of their operations that reduce or offset emissions on their behalf, provided that these projects are based in Alberta. Prior to investing, the offset reductions, offered by a prospective operation, must be verified by a third party to ensure that the emission reductions are real.

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

### ***Review of Alberta Royalty and Tax Regime***

On February 16, 2007, the Alberta Government announced that a review of the province's royalty and tax regime (including income tax and freehold mineral rights tax) pertaining to oil and gas resources, including oil sands, conventional oil and gas and coalbed methane, will be conducted by a panel of experts, with the assistance of individual Albertans and key stakeholders. The review panel is to produce a final report that will be presented to the Minister of Finance by August 31, 2007. At this time, the Trust cannot determine the potential impact of any changes to the royalty rate on its operations.

### **Critical Accounting Estimates**

The reader is advised that the critical accounting estimates, policies, and practices as described in the Management Discussion and Analysis in the Trust's December 31, 2006 Annual Report continue to be critical in determining True's unaudited financial results as at March 31, 2007. Except as described in Note 3 of the attached unaudited interim consolidated financial statements, there were no changes in accounting policies for the three month period ended March 31, 2007.

## **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 circumstance.

## **Controls and Procedures**

### **Disclosure Controls and Procedures**

Disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to the Trust, including its consolidated subsidiaries, is made know to the Trust's Chief Executive Officer and Chief Financial Officer by others within those entities, particularly during the period in which the annual filings are being prepared.

### **Internal Controls over Financial Reporting**

The Trust's Chief Executive Officer and Chief Financial Officer have designed or caused to be designed under their supervision internal controls 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.

The Trust's Chief Executive Officer and Chief Financial Officer are required to cause the Trust to disclose herein any change in the Trust's internal control over financial reporting that occurred during the Trust's most recent interim period 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 the three months ended March 31, 2007, that has materially affected, or are reasonably likely to materially affect, the Trust's internal control of 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.

## Sensitivity Analysis

The table below shows sensitivities to cash flow as a result of product price and operational changes. This is based on actual prices received for the three month period ended March 31, 2007 and average production volumes of 18,500 boe/d during that period, as well as the same level of debt outstanding at March 31, 2007. Diluted weighted average trust units is based upon the first quarter of 2007. 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 cash flow as shown in the table below:

Sensitivity Analysis	Cash Flow from Operations (annualized) (\$000s)	Cash Flow from Operations Per Diluted Unit (\$)
Change of US \$1/bbl WTI	2,800	0.04
Change of \$0.10/ mcf	2,600	0.04
Change of US \$0.01 Cdn/ US exchange rate	1,400	0.02
Change in prime of 1%	1,700	0.02

## Selected Quarterly Consolidated Information

The following table sets forth selected consolidated financial information of the Trust for the most recently completed quarters ending at the first quarter of 2007.

2007 – Quarter ended (unaudited) (\$000s, except per unit amounts)	March 31
Revenues before royalties and hedging	71,196
Cash flow from operations <sup>(1)</sup>	29,988
Cash flow from operations per unit <sup>(1)</sup>	
Basic	\$0.43
Diluted	\$0.42
Net income (loss)	(8,571)
Net income (loss) per unit	
Basic	\$(0.12)
Diluted	\$(0.12)
Net capital expenditures (cash)	28,103
Distributions declared	16,866
Distributions per unit	\$0.24

2006 – Quarter ended (unaudited) (\$000s, except per unit amounts)	March 31	June 30	Sept. 30	Dec. 31
Revenues before royalties and hedging	46,396	43,004	54,263	77,250
Cash flow from operations <sup>(1)</sup>	18,995	16,386	23,225	31,785
Cash flow from operations per unit <sup>(1)</sup>				
Basic	\$0.52	\$0.44	\$0.52	\$0.45
Diluted	\$0.52	\$0.42	\$0.50	\$0.44
Net income (loss)	3,259	12,243	1,652	(250,718)
Net income (loss) per unit				
Basic	\$0.09	\$0.43	\$0.04	\$(3.58)
Diluted	\$0.09	\$0.42	\$0.04	\$(3.58)
Net capital expenditures (cash)	22,585	(7,078)	46,166	30,341
Distributions declared	26,150	27,771	36,846	33,588
Distributions per unit	\$0.72	\$0.72	\$0.72	\$0.48
<hr/>				
2005 – Quarter ended (unaudited) <sup>(2)</sup> (\$000s, except per unit amounts)	March 31	June 30	Sept. 30	Dec. 31
Revenues before royalties and hedging	22,441	33,663	44,510	61,056
Cash flow from operations <sup>(1)</sup>	10,732	18,013	25,500	32,892
Cash flow from operations per unit <sup>(1)</sup>				
Basic	\$0.63	\$0.73	\$1.04	\$1.02
Diluted	\$0.61	\$0.72	\$1.01	\$1.00
Net income (loss)	1,030	3,130	6,502	3,228
Net income (loss) per unit				
Basic	\$0.06	\$0.13	\$0.26	\$0.10
Diluted	\$0.06	\$0.13	\$0.26	\$0.10
Net capital expenditures (cash)	13,161	21,316	28,651	52,843
Distributions declared	-	-	-	17,361
Distributions per unit <sup>(2)</sup>	-	-	-	\$0.48

<sup>(1)</sup> refer to "Non-GAAP Measures" in respect of the term "cash flow from operations" and "cash flows from operations per unit".

<sup>(2)</sup> restated for changes in accounting policies and to reflect the consolidation of units effective November 2, 2005.

The reasons for differences in results experienced from the fourth quarter of 2006 to the first quarter of 2007 are described previously in this report.

The quarterly results as presented for 2005 and 2006 varied significantly for two main reasons: 1) the timing of acquisitions during 2005 and 2006 and 2) changes in commodity prices over those periods.

During 2005, True completed two acquisitions. The acquisition of Meridian Energy Corporation was closed effective March 15, 2005 and the reverse takeover of TKE Energy Trust closed on November 2, 2005. In addition, True completed the purchases of Shellbridge and Prairie Schooner on June 23, 2006 and September 22, 2006, respectively.

True's revenue, net income, and cash flow from operations over 2005 and 2006 has reflected its production base after considering the timing of the above noted acquisitions, the results of ongoing drilling activities, as well as the changes in commodity prices, primarily that for natural gas. Beginning in the first quarter of 2005 and continuing into the first quarter of 2006, natural gas revenue was gradually increasing which resulted in a corresponding increase in the Trust's petroleum and natural gas revenue, net income and cash flow from operations in the period. This trend started to reverse in the second quarter of 2006 with declining natural gas prices influencing a corresponding relative decrease in the Trust's revenues, net income and cash flows from operations.

Net income also reflects an increase in DD&A rates since primarily since the November 2005 reverse takeover of TKE offset by future tax recoveries beginning in the same period. The increase in the Trust's DD&A rate is due to an increase in its depletable base as a result of the acquisitions and further capital spending. Futures tax recoveries recognized since December 2005 result from additional interest deductions associated with True's new Trust structure as well as reductions in rates for both federal and provincial taxes which were enacted during 2006. Net income for the fourth quarter of 2006 is also reflective of a ceiling test write-down of \$110.0 million and a goodwill impairment charge of \$169.8 million.

**TRUE ENERGY TRUST**  
**CONSOLIDATED BALANCE SHEETS**

As at March 31 and December 31 (unaudited)

<b>(\$000s)</b>	<b>2007</b>	<b>2006</b>
<b>ASSETS</b>		
Current assets		
Accounts receivable	\$ 62,508	\$ 73,199
Deposits and prepaid expenses	3,247	7,928
Capital taxes receivable	41	
Commodity contract asset (note 18)	853	-
	<u>66,649</u>	<u>81,127</u>
Property, plant and equipment (note 6)	912,511	931,979
Deferred financing charges (note 8)	-	3,552
Total assets	<u>\$ 979,160</u>	<u>\$1,016,658</u>
<b>LIABILITIES</b>		
Current liabilities		
Accounts payable and accrued liabilities	\$ 97,515	\$ 107,431
Distribution payable to unitholders	-	8,433
Capital taxes payable	-	1,513
Current portion of obligations under capital lease	29	111
Commodity contract liability (note 18)	1,555	-
	<u>99,099</u>	<u>117,488</u>
Long-term debt (note 7)	178,379	157,904
Convertible debentures (note 8)	78,243	81,551
Asset retirement obligations (note 9)	26,421	26,605
Future income taxes (note 14)	111,372	123,861
Total liabilities	<u>493,514</u>	<u>507,409</u>
<b>NON-CONTROLLING INTEREST</b>		
Exchangeable shares of subsidiary (note 10)	4,099	4,153
<b>UNITHOLDERS' EQUITY</b>		
Unitholders' capital (note 11)	876,920	876,904
Equity component of convertible debentures (note 8)	5,119	5,119
Contributed surplus (note 12)	14,000	12,818
Deficit	(415,085)	(389,745)
Accumulated other comprehensive income	593	-
Total unitholders' equity	<u>481,547</u>	<u>505,096</u>
Total liabilities and unitholders' equity	<u>\$ 979,160</u>	<u>\$ 1,016,658</u>

See accompanying selected notes to the consolidated financial statements.

**TRUE ENERGY TRUST**  
**CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME**

For the three months ended March 31 (unaudited)

<i>(\$000s)</i>	<b>2007</b>	<b>2006</b>
<b>REVENUES</b>		
Petroleum and natural gas sales	\$ 71,196	46,396
Royalties	(14,894)	(10,641)
Gain on commodity contracts (note 18)	679	-
	<u>56,981</u>	<u>35,755</u>
<b>EXPENSES</b>		
Production	14,972	9,167
Transportation	689	973
General and administrative	4,904	2,597
Interest and financing charges	4,547	1,763
Unit-based compensation (note 12)	1,112	1,410
Depletion, depreciation and accretion	47,458	29,212
Special meeting costs (note 15)	3,805	-
	<u>77,487</u>	<u>45,122</u>
<b>INCOME (LOSS) BEFORE TAXES</b>	(20,506)	(9,367)
<b>TAXES</b> (note 14)		
Capital taxes	932	571
Future income taxes (recovery)	(12,829)	(13,233)
	<u>(11,897)</u>	<u>(12,662)</u>
<b>NET INCOME (LOSS) BEFORE NON-CONTROLLING INTEREST</b>	(8,609)	3,295
Non-controlling interest (note 10)	(38)	36
<b>NET INCOME (LOSS)</b>	(8,571)	3,259
Net changes in cash flow hedges (net of tax of \$1.6 million)	(3,156)	-
<b>COMPREHENSIVE INCOME (LOSS)</b>	<u>\$ (11,727)</u>	<u>\$ 3,259</u>
Net income (loss) per trust unit (note 16)		
Basic	\$ (0.12)	\$ 0.09
Diluted	<u>\$ (0.12)</u>	<u>\$ 0.09</u>

*See accompanying selected notes to the consolidated financial statements.*

**TRUE ENERGY TRUST**  
**CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY**

For the three months ended March 31 (unaudited)

(\$000s)	2007	2006
<b>UNITHOLDERS' CAPITAL</b>		
Balance, beginning of period	\$ 879,904	\$ 418,968
Exchangeable shares converted (note 11)	16	2,864
Units issued pursuant to DRIP	-	1,317
Balance, end of period	<u>876,920</u>	<u>423,149</u>
<b>EQUITY COMPONENT OF CONVERTIBLE DEBENTURES</b>		
Balance, beginning of period	5,119	-
Conversion feature on convertible debentures issued	-	-
Balance, end of period	<u>5,119</u>	<u>-</u>
<b>CONTRIBUTED SURPLUS</b>		
Balance, beginning of period	12,818	5,127
Unit-based compensation expense (note 12)	1,182	1,630
Balance, end of period	<u>14,000</u>	<u>6,757</u>
<b>DEFICIT</b>		
Balance, beginning of period	(389,745)	(31,826)
Net income (loss)	(8,571)	3,259
Impact of change in accounting policy for financial instruments on January 1, 2007 (net of tax of \$0.05 million) (note 3)	97	-
Distributions declared	(16,866)	(26,150)
Balance, end of period	<u>(415,085)</u>	<u>(54,717)</u>
<b>ACCUMULATED OTHER COMPREHENSIVE INCOME</b>		
Balance, beginning of period	-	-
Impact of new cash flow hedge accounting standards on January 1, 2007 (net of tax of \$1.8 million) (note 3)	3,749	-
Reclassification to earnings of net hedging gains on commodity contracts (net of tax of \$1.6 million)	(3,156)	-
Balance, end of period	<u>593</u>	<u>-</u>
<b>TOTAL UNITHOLDERS' EQUITY</b>	<u>\$ 481,547</u>	<u>\$ 375,189</u>

See accompanying selected notes to the consolidated financial statements.

**TRUE ENERGY TRUST**  
**CONSOLIDATED STATEMENTS OF CASH FLOWS**

For the three months ended March 31 (unaudited)

(\$000s)

	2007	2006
<b>Cash provided by (used in):</b>		
<b>CASH FLOW FROM OPERATING ACTIVITIES</b>		
Net income (loss)	\$ (8,571)	\$ 3,259
Items not involving cash:		
Non-controlling interest (note 10)	(38)	36
Depletion, depreciation and accretion	47,458	29,212
Unit-based compensation (note 12)	1,112	1,410
Unrealized loss on commodity contracts (note 18)	2,465	-
Accretion on convertible debentures (note 8)	391	-
Future income taxes (recovery) (note 14)	(12,829)	(13,233)
Capital taxes	-	(1,689)
	<u>29,988</u>	<u>18,995</u>
Change in non-cash working capital (note 13)	<u>18,227</u>	<u>(8,386)</u>
	<u>48,215</u>	<u>10,609</u>
<b>CASH FLOW FROM (USED IN) FINANCING ACTIVITIES</b>		
Increase in bank debt	21,495	38,488
Obligations under capital lease	(82)	(48)
Payment of cash component of distributions	(25,299)	(24,774)
	<u>(3,886)</u>	<u>13,666</u>
Change in non-cash working capital (note 13)	<u>57</u>	<u>-</u>
	<u>(3,829)</u>	<u>13,666</u>
<b>CASH FLOW FROM (USED IN) INVESTING ACTIVITIES</b>		
Additions to property, plant and equipment	(46,546)	(22,585)
Proceeds on sale of property, plant and equipment	18,443	-
	<u>(28,103)</u>	<u>(22,585)</u>
Change in non-cash working capital (note 13)	<u>(16,283)</u>	<u>(1,690)</u>
	<u>(44,386)</u>	<u>(24,275)</u>
Change in cash	-	-
Cash, beginning of year	-	-
Cash, end of year	\$ -	\$ -

See accompanying selected notes to the consolidated financial statements.

## SELECTED NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

March 31, 2007 and 2006 (unaudited)

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### 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. Through a Plan of Arrangement (the "TKE Arrangement") that became effective on November 2, 2005, True Energy Inc. became the Trust.

Pursuant to the TKE Arrangement, True Energy Inc. and TKE Energy Trust ("TKE") entered into a business combination whereby True Energy Inc. acquired TKE in a reverse takeover, thus creating True Energy Trust and a publicly listed exploration focused company, Vero Energy Inc.

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., its wholly owned subsidiary Marengo Exploration Ltd., True Oil & Gas Ltd., True Energy Partnership and TKE Energy Partnership. The Trust owns, directly and indirectly, 100% of the common shares, (excluding the exchangeable shares – see note 10) of True Energy Inc., Marengo Exploration Ltd., True Oil & Gas Ltd. and 100% of the interests of True Energy Partnership and TKE Energy Partnership. The activities of True Energy Inc., Marengo Exploration Ltd., True Oil & Gas Ltd. and the partnerships, 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. and True Oil & Gas Ltd. 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., Marengo Exploration Ltd., True Oil & Gas Ltd., True Energy Partnership and TKE Energy Partnership, 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 interim consolidated financial statements of the Trust have been prepared by management in accordance with generally accepted accounting policies in Canada. The unaudited interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2006, except as described in note 3. The interim consolidated financial statement note disclosures do not include all of those required by Canadian generally accepted accounting principles ("GAAP") applicable for annual financial statements. Accordingly, the interim consolidated financial statements should be read in conjunction with the consolidated financial statements and the notes thereto contained in the Trust's annual report for the year ended December 31, 2006.

### 3. CHANGES IN ACCOUNTING POLICIES

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". Handbook Section 3251 "Equity" was also effective for True on January 1, 2007. In accordance with these standards, prior period financial statements have not been restated.

At January 1, 2007, the following adjustments were made to the balance sheet to adopt the new standards:

<b><i>Increase (decrease) (\$000s)</i></b>	<b>At January 1, 2007</b>
Commodity contract asset	\$ 8,905
Deposits and prepaid expenses	
Deferred commodity contract premiums	(3,310)
Prepaid interest	(1,020)
	(4,330)
Deferred financing charges	(3,552)
Long-term debt	(1,020)
Convertible debentures	(3,697)
Future income tax liability	1,894
Deficit, net of income taxes of \$0.05 million	(97)
Accumulated other comprehensive income	
Cash flow hedges, net of income taxes of \$1.8 million	3,749

**a. Financial instruments – recognition and measurement**

This new standard requires all financial instruments within its scope, including all derivatives, to be 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. Changes to the measurement of existing financial assets and liabilities at the date of adoption were adjusted to either opening retained earnings or opening accumulated other comprehensive income as noted above.

**b. Derivatives**

The Trust continues to utilize 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. Refer to note 18 to the Trust's 2006 annual financial statements for additional disclosure on the Trust's risk management objectives and policies.

The Trust has elected to account for its commodity sales 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. Prior to adoption of the new standards, physical receipt and delivery contracts did not fall within the scope of the definition of a financial instrument and were also accounted for as executory contracts.

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. Prior to adoption, financial derivatives which were designated and qualified for cash flow hedge accounting were recognized on an accrual basis.

Prior to January 1, 2007, the Trust applied hedge accounting, under the former Accounting Guideline 13 standard, to its financial derivatives, being commodity price risk management contracts. On January 1, 2007, the Trust discontinued hedge accounting for all existing financial derivatives. As a result, the mark-to-market gain on these financial derivatives, 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 will be reclassified to income in future periods as the original hedged transactions affect net earnings. From January 1, 2007 forward, the changes in fair value of such derivatives will be recognized in net income when incurred.

**c. Embedded derivatives**

On adoption, the Trust elected to recognize, as separate assets and liabilities, only those embedded derivatives in hybrid instruments issued, acquired or substantively modified after January 1, 2003. The Trust did not identify any material embedded derivatives which required separate recognition and measurement.

**d. Other comprehensive income**

The new standards require a statement of comprehensive income, which is comprised of net income and other comprehensive income which, for the Trust, relates to changes in gains or losses on derivatives that were previously designated as cash flow hedges. The Company has combined this new statement with the statement of income.

**e. Effective interest rate method**

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. Prior to January 1, 2007, transaction costs were recorded as deferred charges and recognized in net earnings on a straight-line basis over the life of the financial instrument. On adoption, transaction costs are recognized as if the effective interest rate method had always been applied whereby the amount recognized varies over the life of the financial instrument based on principal outstanding. For the Trust, this adoption required adjustments to prepaid expenses and long-term debt as disclosed in note 7 and to deferred financing costs and the debt component of convertible debentures as disclosed in note 8.

**4. FUTURE CHANGES IN ACCOUNTING POLICIES**

**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.

## 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 will replace Section 3861 "Financial Instruments – Disclosure and Presentation" once 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.

## 5. ACQUISITIONS

### a. Acquisition of Prairie Schooner Petroleum Ltd.

Effective September 22, 2006, the Trust's wholly owned subsidiary, True Energy Inc. ("True Energy"), entered into a business combination with Prairie Schooner Petroleum Ltd. ("Prairie Schooner") whereby True Energy acquired all of the issued and outstanding shares of Prairie Schooner pursuant to a plan of arrangement. The previous shareholders of Prairie Schooner received 1.22 trust units of the Trust for each outstanding Prairie Schooner share and outstanding options were exchanged for options ("replacement options") to purchase trust units adjusted for the exchange ratio and exercisable for ten business days following completion of the transaction (the "Transaction"). An aggregate of 25,759,563 trust units were issued pursuant to the Transaction (including on exercise of the replacement options). Concurrent with the business combination, True Energy and Prairie Schooner amalgamated on September 22, 2006 and continue as True Energy. The value of the transaction, based upon the adjusted weighted average trading price for trust units of the Trust for the five days prior to the transaction announcement on July 26, 2006, of \$13.31, was \$344.4 million (including \$1.6 million in transaction costs). The transaction was accounted for using the purchase method.

The purchase price allocation resulted in an excess purchase price over the fair value of net identifiable assets acquired of approximately \$71.6 million, which was reflected as goodwill. The accounts include the results of Prairie Schooner from September 22, 2006, the date Prairie Schooner shares were exchanged for trust units of the Trust. The purchase equation was adjusted at December 31, 2006 to reflect certain underaccruals for operating and capital expenditures relating to the period prior to September 22, 2006. As a result, accounts payable was increased by \$3.6 million, the future tax liability was reduced by \$1.9 million and goodwill was increased by \$1.7 million. The purchase price equation is as follows:

<u>(\$000's)</u>	
<hr/>	
Cost of acquisition:	
Trust units issued	\$ 342,870
True transaction costs	1,563
	<hr/>
	\$ 344,433
<hr/>	
Allocated at estimated fair values:	
Accounts receivable	\$ 32,295
Deposits and prepaid expenses	1,075
Property, plant and equipment	435,346
Goodwill	71,601
Bank debt	(67,373)
Accounts payable and accrued liabilities	(42,636)
Future income taxes	(73,467)
Asset retirement obligations	(12,408)
	<hr/>
	\$ 344,433
<hr/>	

**b. Acquisition of Shellbridge Oil & Gas, Inc.**

Effective June 23, 2006, the Trust's wholly owned subsidiary, True Oil & Gas Ltd. ("True Oil & Gas"), entered into a business combination with Shellbridge Oil & Gas, Inc. ("Shellbridge") whereby True Oil & Gas acquired all of the issued and outstanding shares of Shellbridge pursuant to a plan of arrangement. The previous shareholders of Shellbridge received 0.14 trust units of the Trust for each outstanding Shellbridge share (the "Transaction"), resulting in the issuance of 4,389,366 trust units. Concurrent with the business combination, True Oil & Gas and Shellbridge amalgamated on June 23, 2006 and continue as True Oil & Gas. The value of the transaction, based upon the adjusted weighted average trading price for True Energy Trust units for the five days prior to the transaction announcement on April 11, 2006, of \$15.56, was \$68.8 million (including \$0.5 million in transaction costs). The transaction was accounted for using the purchase method.

The purchase price allocation resulted in an excess purchase price over the fair value of net identifiable assets acquired of approximately \$24.0 million, which was reflected as goodwill. The accounts include the results of Shellbridge effective June 23, 2006, the date Shellbridge shares were exchanged for trust units of the Trust.

The purchase price equation is as follows:

<i>(\$000's)</i>	
Cost of acquisition:	
Trust units issued	\$ 68,299
True transaction costs	520
	<hr/>
	\$ 68,819
Allocated at estimated fair values:	
Cash	\$ 5,218
Accounts receivable	10,005
Deposits and prepaid expenses	161
Property, plant and equipment	47,529
Goodwill	24,017
Accounts payable and accrued liabilities	(13,485)
Future income taxes	(3,330)
Asset retirement obligations	(1,296)
	<hr/>
	\$ 68,819

As at December 31, 2006, a goodwill impairment provision of \$169.8 million was recorded to write-down the goodwill initially recognized from the above and previous year acquisitions.

**6. PROPERTY, PLANT AND EQUIPMENT**

<i>(\$000s)</i>			
		<b>Accumulated depletion and depreciation</b>	
<b>March 31, 2007</b>	<b>Cost</b>		<b>Net book value</b>
Petroleum and natural gas properties	\$1,341,148	\$430,934	\$910,214
Office furniture and equipment	3,292	995	2,297
	<hr/>	<hr/>	<hr/>
	<b>\$1,344,440</b>	<b>\$431,929</b>	<b>\$912,511</b>
December 31, 2006			
Petroleum and natural gas properties	\$1,314,374	\$ 384,110	\$ 930,264
Office furniture and equipment	2,588	873	1,715
	<hr/>	<hr/>	<hr/>
	<b>\$1,316,962</b>	<b>\$ 384,983</b>	<b>\$ 931,979</b>

The Trust has excluded \$46.9 million for undeveloped land and \$48.7 million for estimated salvage from the depletion calculation during the three month period ended March 31, 2007.

For the three month period ended March 31, 2007, the Trust capitalized \$1.0 million of general and administrative expenses and \$0.1 million of unit-based compensation expense directly related to exploration and development activities.

## **7. LONG-TERM DEBT**

The Trust has a \$15 million demand operating facility provided by one Canadian bank and \$210 million extendible revolving term credit facility syndicated by the Canadian chartered bank, a U.S. bank, a foreign bank and one institutional lender. 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% and 1.95%, 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 0.125% and 0.400% on the undrawn portion of the facility, depending on the Trust's debt to cash flow ratio.

As a consequence of adopting new financial instruments standards effective January 1, 2007 as described in note 3, the Trust has made certain adjustments to the presentation of prepaid interest. Previously, this amount was included in deposits and prepaid expenses, however, under the new standard effective January 1, 2007 this amount, being \$1.2 million at March 31, 2007, is now netted against long-term debt and amortized on the effective interest basis.

As at March 31, 2007, there was \$nil million outstanding under the operating facility and \$179.6 million outstanding under the revolving term credit facility. As at March 31, 2007, there is approximately \$45.4 million available under the facility.

The borrowing base is currently scheduled for renewal on or before May 31, 2007.

The revolving period on the new revolving term credit facility ends on June 29, 2007, 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. Payment will not be required under the revolving term facility for more than 365 days from the balance sheet date and as at March 31, 2007 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.

## **8. 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 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 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 as described in note 3, the Trust made certain adjustments to deferred financing charges and the debt component of convertible debentures as noted in the tables 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 three month period ended March 31, 2007 and the year ended December 31, 2006:

<b>Convertible debentures</b>	<b>Number of Debentures</b>	<b>Debt Component (\$000s)</b>	<b>Equity Component (\$000s)</b>
Issued on June 15, 2006	86,250	\$ 81,131	\$ 5,119
Accretion	-	420	-
<b>Balance, December 31, 2006</b>	<b>86,250</b>	<b>81,551</b>	<b>5,119</b>
Impact of change in accounting policy for financial instruments on January 1, 2007 (note 3)	-	(3,699)	-
Accretion	-	391	-
<b>Balance, March 31, 2007</b>	<b>86,250</b>	<b>\$ 78,243</b>	<b>\$ 5,119</b>

The following table shows the deferred financing charges activities for the three month period ended March 31, 2007 and the year ended December 31, 2006:

<b>Deferred financing charges (\$000s)</b>	<b>March 31, 2007</b>	<b>December 31, 2006</b>
Balance, beginning of period	\$ 3,552	\$ -
Costs incurred for convertible debenture offering	-	3,989
Less amortization in the period	-	(437)
Impact of change in accounting policy for financial instruments on January 1, 2007 (note 3)	(3,552)	-
<b>Balance, end of period</b>	<b>\$ -</b>	<b>\$ 3,552</b>

## 9. 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 \$73.7 million which will be incurred between 2007 and 2053. A credit-adjusted risk-free rate of 8.0 percent and an inflation rate of 2.4 percent were used to calculate the fair value of the asset retirement obligation.

<b>(\$000s)</b>	<b>March 31, 2007</b>	<b>December 31, 2006</b>
Asset retirement obligation, beginning of period	\$ 26,605	\$ 10,457
Liabilities acquired through corporate acquisitions	-	13,704
Liabilities incurred on development activities	90	1,210
Changes in prior period estimates	14	810
Liabilities released on dispositions	(799)	(641)
Accretion expense	511	1,065
<b>Asset retirement obligation, end of period</b>	<b>\$ 26,421</b>	<b>\$ 26,605</b>

## 10. EXCHANGEABLE SHARES OF SUBSIDIARY

	March 31, 2007		December 31, 2006	
	Number	Amount (\$000s)	Number	Amount (\$000s)
Balance, beginning of period	403,536	\$ 4,153	788,558	\$ 9,709
Non-controlling interest expense (recovery)	-	(38)	-	(803)
Exchanged for trust units	(1,572)	(16)	(385,022)	(4,753)
<b>Balance, end of period</b>	<b>401,964</b>	<b>\$ 4,099</b>	<b>403,536</b>	<b>\$ 4,153</b>

The exchange ratio is calculated monthly based on the five day weighted average trust unit trading price preceding the monthly effective date, and at March 31, 2007 was 0.75516. The exchangeable shares are not eligible for cash distributions; however cash distributions will increase the exchange ratio.

## 11. UNITHOLDERS' CAPITAL

### a. Trust Units of True Energy Trust

	March 31, 2007		December 31, 2006	
	Number	Amount (\$000s)	Number	Amount (\$000s)
Balance, beginning of period	70,275,703	\$ 876,904	36,176,196	\$ 418,968
Issued to acquire Prairie Schooner (net of issue costs of \$1.8 million)	-	-	25,759,563	341,089
Issued to acquire Shellbridge (net of issue costs of \$0.6 million)	-	-	4,389,366	67,669
Exchangeable shares converted	1,187	16	231,035	4,753
Units issued pursuant to DRIP	-	-	3,574,185	42,608
Issued to acquire property interest	-	-	145,358	1,817
<b>Balance, end of period</b>	<b>70,276,890</b>	<b>\$ 876,920</b>	<b>70,275,703</b>	<b>\$ 876,904</b>

### 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 that is in excess of a 2.5% return on the Trust's consolidated net fixed assets (the "Hurdle Rate"); provided however, that such decrease in the exercise price will not exceed the amount by which the Trust Unit distributions exceed the Hurdle Rate. Effective June 1, 2006, the Trust amended its Hurdle Rate to 0% per quarter. 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.

Unit rights, entitling the holder to purchase units from the Trust, have been granted to directors, officers, employees and service providers of the Trust. Effective May 1, 2006, one third of the initial grant of trust unit incentives 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 three month ended and as at March 31, 2007.

### Unit Rights Continuity

	Average Exercise Price <sup>(a)</sup>	Number
Balance, December 31, 2006	\$ 14.18	5,429,831
Granted	\$ -	-
Forfeited	\$ 14.64	(202,498)
<b>Balance, March 31, 2007</b>	<b>\$ 13.93</b>	<b>5,227,333</b>

### Unit Rights Outstanding

Exercise Price Before Price Reductions	Exercise Price Net of Reductions	At March 31, 2007	Outstanding Exercise Price Net of Price Reductions <sup>(b)</sup>	Remaining Contractual Life <sup>(b)</sup>	Exercisable At March 31, 2007	Exercise Price Net of Price Reductions <sup>(b)</sup>
\$10.58 - \$12.53	\$ 9.91 - \$11.76	1,494,000	\$ 10.16	4.5	-	N/A
\$13.74 - \$14.83	\$12.39 - \$13.56	668,500	\$ 12.82	4.3	-	N/A
\$15.92 - \$16.70	\$14.17 - \$14.92	227,500	\$ 14.37	4.1	29,166	\$ 14.69
\$18.25 - \$20.98	\$15.91 - \$18.86	2,837,333	\$ 16.13	3.6	1,891,554	\$ 16.13
<b>\$10.58 - \$20.98</b>	<b>\$ 9.91 - \$18.86</b>	<b>5,227,333</b>	<b>\$ 13.93</b>	<b>4.0</b>	<b>1,920,720</b>	<b>\$ 16.11</b>

<sup>(a)</sup> Exercise prices reflect grant prices less reduction in exercise prices.

<sup>(b)</sup> Based on weighted average unit rights outstanding.

#### 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 three months ended March 31, 2007, the Trust matched \$0.1 million under the plan.

## 12. CONTRIBUTED SURPLUS

(\$000s)	March 31, 2007	December 31, 2006
Balance, beginning of period	\$ 12,818	\$ 5,127
Unit-based compensation expense	1,182	7,691
<b>Balance, end of period</b>	<b>\$ 14,000</b>	<b>\$12,818</b>

### Unit-based Compensation

During the three months ended March 31, 2007, the Trust granted nil unit incentive rights to employees and directors. During the quarter, the Trust recorded unit-based compensation of \$1.2 million, of which \$0.07 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. During the three month period ended March 31, 2007, there were no new incentive rights granted.

### 13. SUPPLEMENTAL CASH FLOW INFORMATION

#### Cash Interest and Taxes Paid

(\$000s)	Three months ended March 31,	
	2007	2006
Cash paid:		
Interest	\$ 2,560	\$ 988
Taxes (net of refunds)	\$ 2,493	\$ 2,654

#### Change in Non-cash Working Capital

(\$000s)	Three months ended March 31,	
	2007	2006
Changes in non-cash working capital items:		
Accounts receivable	\$ 10,691	\$ (8,755)
Deposits and prepaid expenses	2,783	(386)
Accounts payable and accrued liabilities	(9,918)	(935)
Capital taxes receivable/payable	(1,555)	-
	\$ 2,001	\$ (10,076)
Changes related to operating activities	\$ 18,227	\$ (8,386)
Changes related to financing activities	57	-
Changes related to investing activities	(16,283)	(1,690)
	\$ 2,001	\$ (10,076)

### 14. 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. The Trust does not recognize any future income tax assets or liabilities on "temporary differences" (difference between the accounting basis and tax basis of assets and liabilities) in the Trust. As at March 31, 2007, this "temporary difference" (tax basis exceeds accounting basis) is \$11.8 million. The Trust's subsidiaries are subject to income taxation and provide income tax obligations based upon statutory corporate rates.

As at March 31, 2007, the Trust's subsidiaries have tax basis of approximately \$498 million that is available to shelter future taxable income. Included in this tax basis are estimated non-capital loss carry forwards of approximately \$6.2 million that expire in years through 2026. In addition, the Trust has approximately \$24 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 33.3% (2006: 37.5%) to earnings before income taxes. This difference results from the following items:

(\$000s)	Three months ended March 31,	
	2007	2006
Expected income tax expense (recovery)	\$ (6,819)	\$ (3,512)
Amount in Trust income	(7,090)	(9,591)
Crown royalties and charges	-	989
Resource allowance	-	(990)
Unit based compensation expense	370	529
Change in enacted tax rates	918	(579)
Other	(208)	(79)
Future income tax expense (recovery)	(12,829)	(13,233)
Capital tax expense	932	571
<b>Total tax expense (recovery)</b>	<b>\$ (11,897)</b>	<b>\$ (12,662)</b>

The October 31, 2006 announcement of the Tax Fairness Plan by the Federal Government anticipates a distribution tax on distributions from publicly traded income trusts and similar structures. For existing income trusts and limited partnerships, the government is proposing a four-year transition period. 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.

The government's plans must first be enacted in Parliament and it may be some time before the plans, translated into legislation, are substantially enacted, particularly given the fact that there is a minority government in place. As such, as at March 31, 2007, and until third reading of the Bill in Parliament, current and future income taxes have not been adjusted as a result of this recent announcement. If implemented as currently proposed, the Trust would be required to recognize in its accounts, in the period in which the change is substantively enacted, future income taxes on temporary differences in the Trust.

## 15. 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 will 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 plan of arrangement was not approved.

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

## 16. PER TRUST UNIT AMOUNTS

	<b>Three months ended March 31,</b>	
	<b>2007</b>	<b>2006</b>
Basic trust units outstanding	70,276,890	36,399,240
Dilutive effect of:		
Trust unit incentive rights outstanding	5,227,333	3,273,165
Units issuable for exchangeable shares	303,547	334,372
Units issuable for convertible debentures	5,390,625	-
Diluted trust units outstanding	81,198,395	40,006,777
Weighted average trust units outstanding	70,275,770	36,296,327
Dilutive effect of exchangeable shares, trust unit incentive plan and convertible debentures (1)	303,547	334,372
Diluted weighted average trust units outstanding	70,579,317	36,630,699

<sup>(1)</sup> A total of 5,227,333 (2006: 3,273,165) trust incentive units and 5,390,625 (2006: nil) trust units issuable pursuant to the conversion of convertible debentures were excluded from the calculation for the three month period ended March 31, 2007 as they were not dilutive.

## 17. RELATED PARTY TRANSACTIONS

During the three month period ended March 31, 2007, the Trust paid \$0.9 million (2006: \$0.1 million) for legal services provided by a firm in which a current director is a partner. These payments were made in the normal course of operations, on commercial terms, and therefore were recorded at the exchange amount.

## 18. FINANCIAL INSTRUMENTS

At March 31, 2007, the following table provides the carrying amount and fair value of the Company's financial instruments:

(\$000s)	Carrying amount	Fair value
Commodity contract asset	\$ 853	\$ 853
Commodity contract liability	1,555	1,555
Long-term debt	178,379	178,379
Convertible debentures		
Debt component	78,243	
Equity component	5,119	
	83,362	81,300

The carrying values of accounts receivable, capital taxes receivable, and accounts payable and accrued liabilities approximate their fair value due to their short-term maturity.

The Trust's derivatives are exchange traded or transacted in an over-the-counter market. Where available, valuation is determined by reference to readily available public data.

The carrying value of long-term debt approximates fair value due to the cost of borrowing being at a floating rate..

The fair value of convertible debentures is based upon the closing market trading price as at March 31, 2007.

For the three month period ended March 31, 2007, the statement of income included the following:

(\$000s)	2007
Change in fair value of derivative assets and liabilities included in	
Gain on commodity contracts	\$ 679
Interest expense	4,547

The Trust has entered into commodity price risk management arrangements as follows:

Type	Period	Volume	Price Floor	Price Ceiling	Index
Oil put option	Jan. 1, 2007 to June 30, 2007	1,000 bbl/d	\$ 70.00 US	-	WTI
Oil put option	April 1, 2007 to June 30, 2007	1,200 bbl/d	\$ 60.00 US	-	WTI
Oil put option <sup>(1)</sup>	July 1, 2007 to Sept. 30, 2007	2,000 bbl/d	\$ 60.00 US	-	WTI
Oil collar <sup>(1)</sup>	Oct. 1, 2007 to March 31, 2008	2,000 bbl/d	\$ 65.00 US	\$ 75.00 US	WTI
Natural Gas collar	April 1, 2007 to Oct. 31, 2007	5,000 GJ/day	\$ 7.00 CDN	\$ 11.00 CDN	AECO C
Natural Gas collar	April 1, 2007 to Oct. 31, 2007	5,000 GJ/day	\$ 7.00 CDN	\$ 8.76 CDN	AECO C
Natural Gas collar	April 1, 2007 to Oct. 31, 2007	5,000 GJ/day	\$ 7.00 CDN	\$ 8.12 CDN	AECO C
Natural Gas fixed	April 1, 2007 to Oct. 31, 2007	5,000 GJ/day	\$ 7.10 CDN	\$ 7.10 CDN	AECO C
Natural Gas fixed	April 1, 2007 to Dec. 31, 2007	5,000 GJ/day	\$ 7.00 CDN	\$ 7.00 CDN	AECO C

<sup>(1)</sup> These contracts were entered into subsequent to March 31, 2007.

For the three month period ended March 31, 2007, the gain (loss) on commodity contracts was comprised of the following:

(\$000s)	Activity in the period	Adjustments for new standards <sup>(1)</sup>	Total
<b>Gain (loss) on commodity contracts</b>			
Realized <sup>(2)</sup>	\$ 5,576	\$ (2,432)	\$ 3,144
Unrealized <sup>(3)</sup>	(9,607)	7,142	(2,465)
	\$ (4,031)	\$ 4,710	\$ 679

<sup>(1)</sup> Refer to note 3 which describes the transitional adjustments for adoption of the accounting for the new financial instrument standards in relation to the Trust's commodity contracts.

<sup>(2)</sup> Realized gains and losses on commodity contracts represent actual cash settlements and other amounts paid under these contracts.

<sup>(3)</sup> Unrealized gains and losses on commodity contracts represent non-cash adjustments for changes in the fair value of these contracts during the period.

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 of True trade on the Toronto Stock Exchange ("TSX") under the symbol TUI.UN. For further information, please contact:

Paul R. Baay, President & CEO (403) 750-1272  
or  
Edward J. Brown, CA, Vice President, Finance & CFO (403) 750-2655  
or  
Scott Koyich, Investor Relations (403) 750-2428  
or  
Troy Winsor, US Investor Relations (800) 663-8072

**True Energy Trust**  
2300, 530 – 8<sup>th</sup> Avenue SW  
Calgary, Alberta T2P 3S8  
Phone: (403) 266-8670  
Fax: (403) 264-8163  
[www.trueenergytrust.com](http://www.trueenergytrust.com)