



For Immediate Release
TSX: TUI.UN

TRUE ENERGY TRUST ANNOUNCES THIRD QUARTER 2007 FINANCIAL RESULTS

November 8, 2007 – (TSX: TUI.UN) True Energy Trust (“True” or the “Trust”) announces its financial and operating results for the three and nine months ended September 30, 2007. Highlights from the quarter include:

- In the third quarter of 2007, monthly distributions of \$0.08 per unit were declared and paid on August 15, 2007, September 17, 2007 and October 15, 2007. The Board has announced it has set a distribution policy for the fourth 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 strategy for the distribution level is consistent with providing a balance between providing income to unit holders and funding for True’s capital program.
- True generated average sales volumes for the third quarter of 2007 of 14,096 boe/d as compared to 13,248 boe/d for the same period in 2006, representing a 6% increase. Sales volumes decreased 18% from second quarter 2007 volumes. In addition to the property dispositions completed during the first nine months of 2007, third party plant turnarounds and other operational challenges resulted in lower sales volumes in the quarter. Based upon field estimates, current production is approximately 15,500 boe/d and increasing.
- Cash flow from operations* for the third quarter of 2007 was \$17.5 million on gross sales of \$50.5 million compared to cash flow from operations of \$23.2 million on gross sales of \$54.3 million for the same period in 2006. The decrease in cash flow for the 2007 third quarter was primarily the result of lower realized natural gas and overall crude oil, condensate and NGL commodity prices, offset by marginally higher production volumes as compared to the same period in 2006. In comparison, cash flow from operations for the second quarter of 2007 was \$34.2 million on gross sales of \$75.0 million.
- Three additional minor property dispositions closed in the third quarter for net proceeds of \$3.8 million.
- Execution of the Kerrobert steam assisted gravity drainage (“SAGD”) project is on track. Steam injection commenced in late September and after an initial “warm-up” phase, the four thermal production wells are now configured for fluid production. Oil production on these wells is expected to ramp up during the remainder of the fourth quarter, reaching a peak rate of approximately 500 bbls/d per well pair late in 2007 or early in first quarter 2008, thereby increasing total heavy oil production in the Kerrobert area to approximately 4,000 bbls/d.
- True recently entered into three new commodity price risk management contracts: 1) an oil collar with a West Texas Intermediate (“WTI”) reference crude oil price floor of US\$65.00 per barrel and a price ceiling of US\$82.00 per barrel on 1,000 barrels per day for the second quarter of 2008 through to the fourth quarter of 2008; and 2) two AECO reference price natural gas fixed price contracts at \$6.65 per GJ on a total of 15,546 GJ per day for the period of January 1, 2008 through December 31, 2008. Currently, the Trust has hedged volumes of 2,000 bbls/d of crude oil and 15,055 GJ/d of natural gas for the fourth quarter 2007, 2,000 bbls/d of crude oil and 20,546 GJ/d of natural gas for the first quarter of 2008, and 2,000 bbls/d of crude oil and 15,546 GJ/d of natural gas for the second to fourth quarters of 2008.
- On October 25, 2007, the Alberta government introduced a significant increase to royalty terms for Alberta’s oil and gas sector, effective in 2009, as explained more fully in the Management’s Discussion and Analysis of this report. Higher royalties undoubtedly reduce project economics and the consequent impact on future capital is yet to be determined. The overall impact of the new Alberta royalty regime on True’s operations is mitigated by True’s Saskatchewan properties and lower shallow gas royalty rates associated with True’s natural gas weighted production

portfolio. As a result, the new Alberta royalty rate increases are not anticipated to have a material impact on True's operations.

- Over the past year, the energy sector has been impacted by an increasing number of new pressures. Among these are government policy changes such as the new taxation to eliminate the majority of income trusts, reduced capital investment incentives, lofty environmental targets, onerous regulatory restrictions, and most recently, increases in the royalty burden associated with "Alberta's New Royalty Framework." As a natural gas weighted Trust, True is faced with operating in the current reduced natural gas price environment with indications that 2008 will be similar. Despite a robust global crude oil environment, much of the positive impact is being offset by a strengthening Canadian dollar. True is committed to continuous improvement in its cost structure and the prudent allocation of capital. True is focused on improving netbacks, increasing reserve life and looking at opportunities to increase unit holder value.

* Refer to note (2) in the highlights section of the third quarter report in respect of the term "cash flow from operations".

True's third quarter report is presented below.

HIGHLIGHTS

	Three months ended September 30		Nine months ended September 30	
	2007	2006	2007	2006
FINANCIAL <i>(unaudited)</i>				
<i>(CDN\$000s except unit and per unit amounts)</i>				
Revenue (before royalties and hedging ⁽¹⁾)	50,547	54,263	196,734	143,663
Cash flow from operations ⁽²⁾	17,478	23,225	81,658	58,606
Per basic trust unit	\$0.22	\$0.52	\$1.10	\$1.48
Per diluted trust unit ⁽³⁾	\$0.22	\$0.50	\$1.09	\$1.45
Net income (loss)	(17,003)	1,652	(23,833)	17,154
Per basic trust unit	\$(0.21)	\$0.04	\$(0.32)	\$0.43
Per diluted trust unit ⁽³⁾	\$(0.21)	\$0.04	\$(0.32)	\$0.43
Distributions declared	19,132	36,846	54,374	90,767
Per unit	\$0.24	\$0.72	\$0.72	\$2.16
Exploration and development	11,311	33,438	72,655	73,267
Corporate and property acquisitions	139	12,728	1,493	12,920
Capital expenditures - cash	11,450	46,166	74,148	86,187
Property dispositions - cash	(3,806)	-	(31,275)	(24,514)
Corporate acquisitions and other - non-cash	116	436,811	(197)	484,767
Total capital expenditures - net	7,760	482,977	42,676	546,440
Long-term debt	159,212	108,890	159,212	108,890
Convertible debentures	79,021	81,379	79,021	81,379
Working capital deficiency (excess)	(4,380)	55,490	(4,380)	55,490
Total net debt	233,853	245,759	233,853	245,759
Total assets	909,876	1,302,418	909,876	1,302,418
Unitholders' equity	485,075	778,767	485,075	778,767
OPERATING				
Daily sales volumes				
Crude oil and NGLs	(bbls/d)	3,958	5,648	5,316
Natural gas	(mcf/d)	60,827	45,598	67,364
Total oil equivalent	(boe/d)	14,096	13,248	16,544
Average prices				
Crude oil and NGLs	(\$/bbl)	50.54	55.35	46.94
Crude oil and NGLs (including hedging ⁽¹⁾)	(\$/bbl)	44.07	54.98	45.81
Natural gas	(\$/mcf)	5.44	6.02	6.82
Natural gas (including hedging ⁽¹⁾)	(\$/mcf)	6.07	6.02	7.33
Total oil equivalent	(\$/boe)	37.68	44.31	42.87
Total oil equivalent (including hedging ⁽¹⁾)	(\$/boe)	38.57	44.15	44.57
Statistics				
Operating netback	(\$/boe)	15.76	23.66	22.73
Operating netback (including hedging ⁽¹⁾)	(\$/boe)	16.65	23.50	24.42
Production expenses	(\$/boe)	13.13	8.58	11.46
General & administrative	(\$/boe)	3.26	2.12	2.98
Royalties as a % of sales after transportation		21%	25%	18%
			18%	24%

	Three months ended September 30		Nine months ended September 30	
	2007	2006	2007	2006
TRUST UNITS				
Trust units outstanding	79,715,595	69,321,703	79,715,595	69,321,703
Trust unit incentive rights outstanding	6,086,832	5,516,500	6,086,832	5,516,500
Units issuable for exchangeable shares	316,547	272,264	316,547	272,264
Units issuable for convertible debentures	5,390,625	5,390,625	5,390,625	5,390,625
Diluted trust units outstanding	91,509,599	80,501,092	91,509,599	80,501,092
Diluted weighted average trust units ⁽³⁾	79,714,539	45,207,091	74,528,093	39,821,616

TRUST UNIT TRADING STATISTICS

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

High	6.10	15.64	7.47	21.30
Low	4.51	10.32	4.51	10.32
Close	4.95	10.58	4.95	10.58
Average daily volume	364,661	364,342	469,513	328,137

⁽¹⁾ 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 each reporting period until these contracts are settled, at which time realized gains or losses are recorded.

⁽²⁾ The highlights section 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 Management Discussion and Analysis ("MD&A"). Cash flow from operations per trust unit is calculated using the diluted weighted average number of trust units for the period.

⁽³⁾ In computing weighted average diluted earnings per trust unit for the three month period ended September 30, 2007 nil (2006: 272,264) trust units were added to the 79,714,539 (2006: 44,934,827) weighted average number of trust units outstanding during the period for the dilutive effect of exchangeable shares and convertible debentures. A total of 316,547 (2006: nil) exchangeable shares, 6,086,832 (2006: 3,103,033) trust incentive units and 5,390,625 (2006: 5,390,625) 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 September 30, 2007 as they were not dilutive.

In computing weighted average diluted earnings per trust unit for the nine month period ended September 30, 2007 nil (2006: 272,264) trust units were added to the 74,528,093 (2006: 39,549,352) weighted average number of trust units outstanding during the period for the dilutive effect of exchangeable shares and convertible debentures. A total of 316,547 (2006: nil) exchangeable shares, 6,086,832 (2006: 721,377) trust incentive units and 5,390,625 (2006: 5,390,625) trust units issuable pursuant to conversion of convertible debentures were excluded from the calculation of diluted earnings per trust unit for the nine month period ended September 30, 2007 as they were not dilutive. To calculate weighted average diluted cash flow from operations for the nine month period ended September 30, 2007, 316,547 exchangeable shares were added to the denominator, resulting in diluted weighted average trust units of 74,844,639 under this calculation.

REPORT TO UNITHOLDERS

During the third quarter of 2007, the Trust focused on completion of the Kerrobert steam assisted gravity drainage ("SAGD") project, optimization of field operations during a period of significant third party plant turnaround impact, and continued execution of our disposition program. Accomplishments for the third quarter ended September 30, 2007 include:

Distributions

In the third quarter of 2007, monthly distributions of \$0.08 per unit were declared and paid on August 15, 2007, September 17, 2007 and October 15, 2007. The Board has announced it has set a distribution policy for the fourth 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 unit holders and funding for True's capital program.

Production

2007 third quarter sales volumes averaged 14,096 boe/d as compared to 13,248 boe/d for the same period in 2006, representing a 6% increase. For the nine month period ended September 30, 2007, sales volumes averaged 16,544 boe/d as compared to 11,878 boe/d for the same period in 2006. Sales volumes in the third quarter were down 18% from the second quarter 2007 volumes. This takes into account the disposition of certain properties and third party turnarounds during the quarter, as well as further negative prior period net adjustments of approximately 600 boe/d. During the month of September 2007, a major third party plant turnaround in the Willesden Green area of West Central Alberta affected approximately 1,400 boe/d of production for approximately 26 days, 12 days longer than anticipated.

While the extraordinary declines due to various performance issues that were experienced during the second quarter of 2007 at the Mantario heavy oil property have not continued, quarter over quarter averages were negatively impacted approximately by 250 boe/d. During the third quarter of 2007, True participated in 2 gross (1.5 net) heavy oil wells in the Mantario area. The results of the infill drilling program are encouraging and have assisted in stabilizing the decline in this compartmentalized reservoir. The two wells were placed on production via single well batteries at the end of the third quarter of 2007 and are each currently producing approximately 100 boe/d net. The Trust will continue to pursue further infill drilling potential at Mantario.

2 gross (0.6 net) third party operated wells from first quarter 2007 drilling in the Ferrier area were completed and tied in late in the third quarter of 2007. Current production from these wells total approximately 60 boe/d net. A further 3 gross (0.6) net third party operated wells are anticipated to be completed during the fourth quarter.

Regulatory issues in Alberta impacted approximately 700 boe/d during the third quarter of 2007. In July 2007 the Trust was informed by the Alberta Energy and Utilities Board ("AEUB") that applications for natural gas production from 2 wells in the Cold Lake oil sands area had not been made by the previous operator. An internal review of all the Trust's wells within Oil Sands Designated areas discovered further deficiencies and resulted in a requirement to self disclose the non-compliance to the AEUB. The affected wells and the Trust's Two Hills facility – 180 boe/d – were shut-in until the necessary approvals were received on September 26, 2007. In the Doris area re-licensing of a pipeline impacted 175 boe/d until October 18, 2007. In the Brazeau area, Good Production Practice ("GPP") approval was received September 6, 2007 allowing the Trust to increase production rates from the affected light oil pool by approximately 500 boe/d above the previously established allowable rate. Due to a third party equipment failure, volumes could not be increased until mid-September 2007.

Execution of the Kerrobert SAGD project is on track. During the first quarter of 2007, True completed its Phase 1 drilling campaign consisting of five cold producers and four thermal wells. SAGD facility upgrades continued throughout the second and third quarters of 2007. The steam injection commenced in late September and after an initial "warm-up" phase the four thermal production wells are now configured for fluid production. Oil production from these thermal wells is expected to ramp up during the

remainder of the fourth quarter and reach the anticipated peak rates of approximately 500 bbls/d per well pair late in 2007 or early in the first quarter of 2008, thereby increasing total heavy oil production in the Kerrobert area to approximately 4,000 bbls/d.

<i>Reconciliation of Q3 average sales volumes to current estimated production</i>	<i>(In boe/d)</i>
Q3 2007 average sales volumes	14,100
Regulatory issues impacting Q3	700
Plant turnarounds impacting Q3	400
Recent well completions	260
Other	40
Current production estimate	15,500

Based upon field estimates, current production is approximately 15,500 boe/d and increasing. Further focus on recompletion, optimization, and tie-in potential, in conjunction with response from the Kerrobert SAGD expansion start-up is anticipated to provide significant production growth prior to the end of the 2007 year. The Trust is anticipating 2007 annual average volumes of approximately 16,500 boe/d.

Financial

Cash flow from operations for the third quarter was \$17.5 million on gross sales of \$50.5 million compared to cash flow from operations of \$23.2 million on gross sales of \$54.3 million for the same period in 2006. The decrease in cash flow for the 2007 third quarter was primarily the result of lower realized natural gas and overall crude oil, condensate and NGL commodity prices, offset by marginally higher production volumes as compared to the same period in 2006.

Cash flow from operations for the nine month period ended September 30, 2007 was \$81.7 million on gross sales of \$196.7 million compared to cash flow from operations of \$58.6 million on gross sales of \$143.7 million for the same period in 2006.

The net loss for the 2007 third quarter was \$17.0 million compared to net income of \$1.7 million in the third quarter of 2006. The net loss for the nine month period ended September 30, 2007 was \$23.8 million compared to net income of \$17.2 million for the same period in 2006. This is primarily reflective of increased cash flow from operations for the nine month period, offset by a lower future tax recovery and by higher depletion, depreciation and accretion charges.

Dispositions

Dispositions during the third quarter of 2007 consisted of the sale of three separate minor northern Alberta properties, which are outside of the Trust's core areas for future development. These property sales closed during the months of July and August with net proceeds after adjustments of approximately \$3.8 million used to pay down debt. The Trust continues to evaluate further divestiture opportunities, in keeping with its principles of core area focus and operating high working interest production.

Liquidity

True's net debt as at September 30, 2007 was \$233.9 million, representing \$159.2 million outstanding on the credit facility, \$79.0 million in convertible debentures (liability component) and net of the balance of working capital.

The existing credit facility consists of a \$15 million demand operating facility provided by one Canadian bank and a \$175 million extendible revolving term credit facility syndicated by two Canadian chartered banks, a U.S. bank, a Canadian financial institution and one institutional lender. As at September 30, 2007, there is approximately \$31 million undrawn under these lending facilities.

The revolving period on the term credit facility ends on June 30, 2008, unless extended for a further 364 day period. The borrowing base was renewed effective August 31, 2007 and is currently scheduled for renewal on March 31, 2008.

In August 2007, True received Toronto Stock Exchange approval for its normal course issuer bid ("NCIB") for the repurchase of its trust units from August 28, 2007 to August 27, 2008, entitling the Trust to purchase up to approximately 7.8 million of its outstanding trust units. During the third quarter of 2007, no

units were repurchased. Future repurchases will be dependent on excess cash available after consideration of the Trust's priority uses of cash.

True has continued its active commodity price risk management program. True recently entered into three new commodity price risk management contracts: 1) an oil collar with a West Texas Intermediate ("WTI") reference crude oil price floor of US\$65.00 per barrel and a price ceiling of US\$82.00 per barrel on 1,000 barrels per day for the second quarter of 2008 through to the fourth quarter of 2008; and 2) two AECO reference price natural gas fixed price contracts at \$6.65 per GJ on a total of 15,546 GJ per day for the period of January 1, 2008 through December 31, 2008. As of November 8, 2007, the Trust has hedged volumes of 2,000 bbls/d of crude oil and 15,055 GJ/d of natural gas for the fourth quarter 2007, 2,000 bbls/d of crude oil and 20,546 GJ/d of natural gas for the first quarter of 2008, and 2,000 bbls/d of crude oil and 15,546 GJ/d of natural gas for the second to fourth quarters of 2008. The Trust will continue its hedging strategies focusing on maintaining sufficient cash flow to fund True's unitholder distributions and capital program.

Alberta Government Announces New Royalty Framework

The Alberta Government recently has provided some details with respect to its intentions for oil & gas royalties in the province. The newly proposed Alberta royalty regime is to take effect in 2009 and in response to the recommendations of the recent Alberta Royalty Review Panel. True is continuing to assess the impact of the new royalty regime on its ongoing Alberta operations. The actual impact will be determined based on the actual legislation as well as production rates, drilling depths, commodity prices, product mix and the percentage of production from Alberta after January 1, 2009. True's current operations and production are weighted approximately 58% to Alberta; 40% to Saskatchewan and 2% to British Columbia. The overall impact on the new Alberta royalty regime is mitigated by True's Saskatchewan properties and the lower shallow gas Alberta natural gas rate royalty production in True's Alberta conventional oil and gas production portfolio. True is weighted approximately 80% to natural gas production in Alberta. Higher royalties undoubtedly reduce project economics and the consequent impact on future capital is yet to be determined but the increases are not anticipated to have a material impact on True's operations.

The proposed royalty changes are very sensitive to production rate and natural gas prices. The majority of True's current Alberta wells are in the 500m to 1000m depth range and typically produce at lower rates. Based on publicly available information in respect of the New Royalty Framework, and by re-running True's reserves evaluated at December 31, 2006 and using the same assumptions including pricing (an average of consultants forecast prices as at January 1, 2007), True estimates that the proposed royalty rates would result in a positive revision to True's net present value of future net revenues from reserves, as at December 31, 2006, (based upon a 10% discount factor) of approximately 0.8% and a 0.8% increase in net reserves (working interest and royalty interests in reserves after deducting royalty obligations), as at December 31, 2006. Based on the foregoing, the New Royalty Framework would result in a positive revision to True's net asset value, as at December 31, 2006, of approximately 1%.

Over the past year, the energy sector has been impacted by an increasing number of new pressures. Among these are government policy changes such as the new taxation to eliminate the majority of income trusts, reduced capital investment incentives, lofty environmental targets, onerous regulatory restrictions, and most recently, increases in the royalty burden associated with "Alberta's New Royalty Framework." As a natural gas weighted Trust, True is faced with operating in the current reduced natural gas price environment with indications that 2008 will be similar. Despite a robust global crude oil environment, much of the positive impact is being offset by a strengthening Canadian dollar. True is committed to continuous improvement in its cost structure and the prudent allocation of capital. True is focused on improving netbacks, increasing reserve life and looking at opportunities to increase unit holder value.

2008 True Budget

Gas prices continue to show volatility with lack of cold weather and the current supply/demand imbalance. Given the current natural gas price outlook, coming into the winter drilling season, True plans to reduce its first quarter 2008 winter drilling activity compared to the first quarter of 2007. True's first quarter 2008 capital program will not exceed \$10 million which compares to a front end loaded 2007 capital program of approximately \$50 million in first quarter 2007. True will continue to take a balanced approach to the priority use of cash flow between level of distributions and size of its 2008 capital program. Given the nature of True's lands and their inherent advantage of year round access, True will spread its 2008

capital program more evenly through the full year of 2008 to take advantage of reduced service costs during non-peak times. True will focus on increasing its farm-out activity in non-core areas. If the 2008 outlook for commodity prices improves, True would plan to increase its capital spending in third and fourth quarters of 2008.

Personnel Announcements

Further to our press release dated August 20, 2007, True announced my appointment as Chief Executive Officer and Director of True following the resignation of Paul R. Baay as True's Chairman and Chief Executive Officer. William C. (Mickey) Dunn, current Lead Independent Director of True, has reassumed his role as Chairman of the Board and Mr. Baay remains as a director of True. On behalf of the Board, I would like to thank Mr. Baay for his many years of dedicated service since founding True in September of 2000.

Wayne M. Chorney
President, CEO and COO
November 8, 2007

MANAGEMENT'S DISCUSSION AND ANALYSIS

November 8, 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 and nine months ended September 30, 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 November 8, 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 term "distributable cash" which is not a recognized measure under Canadian GAAP. 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.

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, timing of and effects of drilling, tie-in and completion of wells, timing of and the effect of third party plant turnarounds, the effect of government announcements, proposals and legislation, plans regarding hedging, wells to be drilled, 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, distributions and taxability of distributions, 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 exhaustive. Additional information on these and other factors that could effect True's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), at True's website (www.trueenergytrust.com). Furthermore, the forward-looking statements contained herein are made as at the date hereof and True does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

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

Net Income (Loss) and Cash Flow from Operations

True generated cash flow from operations of \$17.5 million (\$0.22 per diluted unit) for the three months ended September 30, 2007, down 25% from the \$23.2 million (\$0.50 per diluted unit) for the third quarter of 2006. The decrease in cash flow for the 2007 third quarter was primarily the result of lower realized natural gas and overall crude oil, condensate and NGL commodity prices, offset by marginally higher production volumes as compared to the same period in 2006. Cash flow from operations for the nine month period ended September 30, 2007 was \$81.7 million (\$1.09 per diluted unit), up 39% from the \$58.6 million (\$1.45 per diluted unit) for the same period in 2006.

The net loss for the 2007 third quarter was \$17.0 million compared to net income of \$1.7 million in third quarter of 2006. The net loss for the nine month period ended September 30, 2007 was \$23.8 million compared to net income of \$17.2 million for the same period in 2006. This is primarily reflective of increased cash flow from operations for the nine month period, offset by a lower future tax recovery and by higher depletion, depreciation and accretion charges.

Cash Flow From Operations and Net Income

(\$000s, except per unit amounts)	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Cash flow from operations	17,478	23,225	81,658	58,606
Basic (\$/unit)	0.22	0.52	1.10	1.48
Diluted (\$/unit)	0.22	0.50	1.09	1.45
Net income (loss)	(17,003)	1,652	(23,833)	17,154
Basic (\$/unit)	(0.21)	0.04	(0.32)	0.43
Diluted (\$/unit)	(0.21)	0.04	(0.32)	0.43

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 September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Cash flow from operations	17,478	23,225	81,658	58,606
Change in non-cash working capital	(2,598)	20,284	(21,842)	4,375
Cash flow from operating activities	14,880	43,509	59,816	62,981
Cash withheld to fund capital expenditures, net of disposition proceeds	(7,644)	(46,166)	(42,873)	(61,673)
Funding from DRIP	-	20,760	-	35,824
Net proceeds from issue of trust units	(11)	-	54,375	-
Proceeds from issue of convertible debentures, net of issue costs	-	-	-	82,227
Bank borrowings (debt repayment) and working capital changes	11,907	18,743	(16,944)	(28,592)
Distributions declared	19,132	36,846	54,374	90,767
Accumulated distributions, beginning of period	176,958	71,282	141,716	17,361
Accumulated distributions, end of period	196,090	108,128	196,090	108,128
Distributions per unit for outstanding units in the period	0.24	0.72	0.72	2.16
Accumulated distributions per unit, beginning of period	3.60	1.92	3.12	0.48
Accumulated distributions per unit, end of period	3.84	2.64	3.84	2.64

The Premium DistributionTM 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.

Sales Volumes

2007 third quarter sales volumes averaged 14,096 boe/d as compared to 13,248 boe/d for the same period in 2006, representing a 6% increase. For the nine month period ended September 30, 2007, sales volumes averaged 16,544 boe/d as compared to 11,878 boe/d for the same period in 2007. Sales volumes in the second quarter decreased 18% from the first quarter 2007 volumes. This takes into account the disposition of certain properties and third party turnarounds during the quarter, as well as further negative prior period net adjustments of approximately 600 boe/d. During the month of September a major third party plant turnaround in the Willesden Green area of West Central Alberta affected approximately 1,400 boe/d of production for approximately 26 days, 12 days longer than anticipated.

While the extraordinary declines due to various performance issues that were experienced during the second quarter at the Mantario heavy oil property have not continued, quarter over quarter averages were negatively impacted approximately by 250 boe/d. During the third quarter of 2007, True participated in 2 gross (1.5 net) heavy oil wells in the Mantario area. The results of the infill drilling program are

encouraging and have assisted in stabilizing the decline in this compartmentalized reservoir. The two wells were placed on production via single well batteries at the end of the third quarter of 2007 and are each currently producing approximately 100 boe/d net. The Trust will continue to pursue further infill drilling potential at Mantario.

2 gross (0.6 net) third party operated wells from first quarter drilling in the Ferrier area were completed and tied in late in the third quarter. Current production from these wells total approximately 60 boe/d net. A further 3 gross (0.6) net third party operated wells are anticipated to be completed during the fourth quarter.

Regulatory issues in Alberta impacted approximately 700 boe/d during the third quarter of 2007. In July 2007 the Trust was informed by the Alberta Energy and Utilities Board ("AEUB") that applications for natural gas production from 2 wells in the Cold Lake oil sands area had not been made by the previous operator. An internal review of all the Trust's wells within Oil Sands Designated areas discovered further deficiencies and resulted in a requirement to self disclose the non-compliance to the AEUB. The affected wells and the Trust's Two Hills facility – 180 boe/d – were shut-in until the necessary approvals were received on September 26, 2007. In the Doris area re-licensing of a pipeline impacted 175 boe/d until October 18, 2007. In the Brazeau area, Good Production Practice ("GPP") approval was received September 6, 2007 allowing the Trust to increase production rates from the affected light oil pool by approximately 500 boe/d above the previously established allowable rate. Due to a third party equipment failure, volumes could not be increased until mid-September 2007.

Execution of the Kerrobert SAGD project is on track. During the first quarter of 2007, True completed its Phase 1 drilling campaign consisting of five cold producers and four thermal wells. SAGD facility upgrades continued throughout the second and third quarters of 2007. The steam injection commenced in late September and after an initial "warm-up" phase the four thermal production wells are now configured for fluid production. Oil production from these thermal wells is expected to ramp up during the remainder of the fourth quarter and reach the anticipated peak rates of approximately 500 bbls/d per well pair late in 2007 or early in the first quarter of 2008, thereby increasing total heavy oil production in the Kerrobert area to approximately 4,000 bbls/d.

Based upon field estimates, current production is approximately 15,500 boe/d and increasing. Further focus on recompletion, optimization, and tie-in potential, in conjunction with response from the Kerrobert SAGD expansion start-up is anticipated to provide significant production growth prior to the end of the 2007 year. The Trust is anticipating 2007 annual average volumes of approximately 16,500 boe/d.

For the three month period ended September 30, 2007, the weighting towards natural gas sales averaged 72% compared to 57% in the same period in 2006. For the nine month period ended September 30, 2007, the weighting towards natural gas averaged 67% compared to 61% for the same period in 2006. Heavy oil sales made up 21% of total production for the third quarter of 2007 compared to 34% in the same period in 2006. In comparison, heavy oil sales made up 18% of total sales in the second quarter of 2007. The September 2006 acquisition of Prairie Schooner Petroleum Ltd. ("Prairie Schooner") added significant natural gas volumes which has increased the natural gas production weighting since that date. Currently, the Trust estimates that the weighting towards natural gas production is approximately 65%.

Sales Volumes

		Three months ended September 30,		Nine months ended September 30,	
		2007	2006	2007	2006
Natural gas	(mcf/d)	60,827	45,598	67,364	43,656
Heavy oil	(bbls/d)	3,001	4,557	3,466	3,127
Light oil and condensate	(bbls/d)	531	834	1,261	1,200
NGLs	(bbls/d)	426	257	589	275
Total crude oil and NGLs	(bbls/d)	3,958	5,648	5,316	4,602
Total boe/d	(6:1)	14,096	13,248	16,544	11,878

Sales of natural gas averaged 60.8 mmcf/d for the third quarter of 2007, compared to 45.6 mmcf/d in 2006, an increase of 33%. In comparison, natural gas volumes averaged 69.5 mmcf/d for the second quarter of 2007. The third party plant turnaround at the Willesden Green area during the third quarter was a significant factor contributing to the reduction in natural gas volumes from the second to third quarter of 2007. Regulatory issues at the Two Hills facility and a Doris area pipeline relicensing also contributed to lower natural gas sales in the quarter.

Crude oil and NGL sales for the third quarter of 2007 averaged 3,958 bbls/d down 30% from average sales of 5,648 bbls/d in the same period of 2006. A significant portion of this 2007 third quarter over 2006 quarter decrease was due to the performance issues encountered in the earlier part of 2007 from the Mantario heavy oil property. In comparison, crude oil and NGL sales for the second quarter of 2007 were 5,546 bbls/d; the decrease from the second quarter of 2007 was primarily due to a reduction in oil volumes related to 2007 property dispositions, further quarter over quarter decreases of approximately 250 boe/d of heavy oil production at Mantario, as well as certain negative prior period crude oil and NGL sales volume adjustments of approximately 800 boe/d.

Commodity Prices

Average Commodity Prices

	Three months ended Sept. 30,			Nine months ended Sept. 30,		
	2007	2006	% Change	2007	2006	% Change
Exchange rate (US\$/Cdn\$)	0.9560	0.8921	7	0.9050	0.8830	2
Natural gas:						
NYMEX (US\$/mmbtu)	6.24	6.17	1	7.02	6.91	2
AECO spot (\$/mcf)	5.14	5.61	(8)	6.52	6.37	2
True's average price (\$/mcf)	5.44	6.02	(10)	6.82	6.61	3
True's average price (including hedging) (\$/mcf)	6.07	6.02	1	7.33	6.61	11
Crude oil:						
WTI (US\$/bbl)	75.15	70.63	6	66.19	68.24	(3)
Edmonton par – light oil (\$/bbl)	80.70	79.73	1	73.69	76.06	(3)
Bow River – medium/heavy oil (\$/bbl)	55.61	51.64	8	52.01	45.18	15
Hardisty Heavy – heavy oil (\$/bbl)	47.43	51.61	(8)	39.35	45.20	(13)
True's average prices (\$/bbl)						
Light crude oil, condensate, and NGLs	76.37	69.68	10	59.64	63.61	(6)
Light crude oil, condensate and NGLs (including hedging)	49.61	67.80	(27)	56.40	62.47	(10)
Heavy crude oil	42.30	51.92	(19)	40.17	44.62	(10)
Total crude oil and NGLs	50.34	55.35	(9)	46.94	50.71	(7)
Total crude oil and NGLs (including hedging)	44.07	54.98	(20)	45.81	50.34	(9)

True's natural gas is primarily sold on the daily spot market. During third quarter of 2007, the AECO Spot reference price decreased by 8% compared to the same period in 2006. True's average sales price before transportation and hedging for the third quarter of 2007 averaged \$5.44/mcf for its natural gas, 10% less than the \$6.02/mcf received in 2006. In comparison, True's average sales price for natural gas averaged \$7.60/mcf for the second quarter of 2006.

For heavy crude oil, True received an average price before transportation of \$42.30/bbl during the third quarter of 2007, a decrease of 19% over 2006 prices. The Bow River reference price increased by 8% and the Hardisty Heavy reference price decreased by 8% over the same period. The majority of True's heavy crude oil density ranges between 11 and 16 degrees API consistent with the Hardisty Heavy reference price. In comparison, True received an average heavy oil price of \$43.01/bbl for the second quarter of 2007.

For light oil, condensate and NGLs, True recorded an average \$76.37/bbl before hedging during the third quarter of 2007, 10% higher than the average price received in 2006. During this same period, the Edmonton par price increased by 1%. In comparison, True received an average oil price for light oil, condensate and NGLs of \$60.59/bbl in the second quarter of 2007. True's realized price increased 26% from the second quarter to the third quarter of 2007, whereas the Edmonton par price increased by 11% over the same period. A portion of this difference was due to prior period negative light oil and condensate volume adjustments with corresponding lower prices, as well as the impact of average condensate prices realized of approximately \$85.00/bbl in the third quarter.

Revenue

Revenue before other income for the third quarter of 2007 was \$48.9 million, 10% less than the \$54.0 million in the same period of 2006. The lower revenue for the third quarter of 2007 was primarily the result of lower realized natural gas and overall crude oil, condensate and NGL commodity prices despite higher natural gas volumes and the lower production volumes for crude oil, condensate and NGLs in the quarter.

(\$000s)	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Light crude oil, condensate and NGLs	6,724	6,994	30,118	25,611
Heavy oil	11,680	21,768	38,009	38,098
Crude oil and NGLs	18,404	28,762	68,127	63,709
Natural gas	30,455	25,241	125,495	78,816
Total revenue before other	48,859	54,003	193,622	142,525
Other	1,688	260	3,112	1,138
Total revenue before royalties and hedging	50,547	54,263	196,734	143,663
Gain (loss) on commodity contracts	1,156	(188)	7,670	(461)
Total revenue before royalties	51,703	54,075	204,404	143,202

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 November 8, 2007, the Trust has hedged volumes of 2,000 bbls/d of crude oil and 15,055 GJ/d of natural gas for the fourth quarter 2007, 2,000 bbls/d of crude oil and 20,546 GJ/d of natural gas for the first quarter of 2008, and 2,000 bbls/d of crude oil and 15,546 GJ/d of natural gas for the second to fourth quarters of 2008. The Trust will continue its hedging strategies 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 19 to the consolidated financial statements for a detailed disclosure of all commodity contracts in place as at November 8, 2007):

Crude oil and liquids Average Volumes (bbls/d)

	Q4 2007	Q1 2008	Q2-Q4 2008
Costless collars	2,000	2,000	2,000
Total bbls/d	2,000	2,000	2,000

Average Price (US\$/bbl WTI)

	Q4 2007	Q1 2008	Q2-Q4 2008
Collar ceiling price	75.00	75.00	82.00
Collar floor price	65.00	65.00	65.00

Natural gas Average Volumes (GJ/d)

	Q4 2007	Q1 2008	Q2-Q4 2008
Costless collars	8,370	5,000	-
Fixed	6,685	15,546	15,546
Total GJ/d	15,055	20,546	15,546

Average Price (\$/GJ AECO C)

	Q4 2007	Q1 2008	Q2-Q4 2008
Collar ceiling price	9.20	9.05	-
Collar floor price	7.40	8.00	-
Fixed	7.03	6.65	6.65

The following is a summary of the gain (loss) on commodity contracts for the three and nine months ended September 30, 2007:

Commodity contracts

(\$000s)	Crude Oil & Liquids	Natural Gas	Q3 2007 Total	Q3 2006 Total
Realized cash gain (loss) on contracts ⁽¹⁾	(101)	4,165	4,064	(188)
Unrealized gain (loss) on contracts	(2,255)	(653)	(2,908)	-
Total gain (loss) on commodity contracts	(2,356)	3,512	1,156	(188)

(\$000s)	Crude Oil & Liquids	Natural Gas	YTD 2007 Total	YTD 2006 Total
Realized cash gain (loss) on contracts ⁽²⁾	962	6,128	7,090	(461)
Unrealized gain (loss) on contracts	(2,598)	3,178	580	-
Total gain (loss) on commodity contracts	(1,636)	9,306	7,670	(461)

(1) Includes crude oil and natural gas commodity contract premiums expensed in the period and the amortization of prior year crude oil and natural gas commodity contract premiums of a total \$0.3 million for the three month period ended September 30, 2007.

(2) Includes crude oil and natural gas commodity contract premiums expensed in the period and the amortization of prior year crude oil and natural gas commodity contract premiums of a total \$3.7 million for the nine month period ended September 30, 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 results for the nine month period September 30, 2007. 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 nine months ended September 30, 2007.

Royalties

For the three months ending September 30, 2007, total royalties were \$9.7 million, compared to \$13.0 million incurred in the same period in 2006. Overall royalties as a percentage of revenue (after transportation costs) in the third quarter of 2007 were 21%, compared with 25% in the same period in 2006. The second quarter of 2007 includes the impact of the reversal of certain over accruals for heavy crude oil and natural gas royalties from prior periods of approximately \$5.3 million. Based upon the latest and most up-to-date information and experience, it was determined that certain prior period royalty accrual estimates were overstated by approximately 2% per month on average as a percentage of revenue after transportation costs. Royalties for the nine months ended September 30, 2007 averaged 18% compared to 24% in the prior period in 2006, primarily a result of this adjustment in the second quarter.

Royalties by Commodity Type <i>(\$000s, except where noted)</i>	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Light crude oil, condensate and NGLs \$/bbl	2,212 25.12	1,837 18.30	6,749 13.36	4,848 12.04
Average light crude oil, condensate, and NGLs royalty rate (%)	33	27	22	19
Heavy Oil \$/bbl	1,278 4.63	5,738 13.68	4,214 4.45	9,350 10.95
Average heavy oil royalty rate (%)	11	28	11	26
Natural Gas \$/mcf	6,237 1.01	5,450 0.97	23,459 1.28	19,125 1.60
Average natural gas royalty rate (%)	21	22	19	25
Total	9,727	13,025	34,422	33,323
\$/boe	7.50	10.69	7.62	10.27
Average total royalty rate (%)	21	25	18	24

Royalties, by Type

(\$000s)	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Crown royalties, net of ARTC	6,499	5,213	19,732	18,107
Indian Oil and Gas Canada royalties	544	972	3,855	2,385
Freehold & GORR	2,684	6,840	10,835	12,831
Total	9,727	13,025	34,422	33,323

Expenses

(\$000s)	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Production	17,024	10,458	51,774	28,946
Transportation	1,671	1,682	4,791	4,145
General and administrative	4,232	2,583	13,468	8,990
Interest and financing charges	4,422	2,793	13,542	6,403
Unit-based compensation	869	1,824	3,256	4,875

Expenses per boe

(\$ per boe)	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Production	13.13	8.58	11.46	8.93
Transportation	1.29	1.38	1.06	1.28
General and administrative	3.26	2.12	2.98	2.77
Interest and financing charges	3.41	2.29	3.00	1.97
Unit-based compensation	0.67	1.50	0.72	1.50

Production Expenses

For the three months ended September 30, 2007, production expenses totaled \$17.0 million, compared to \$10.5 million recorded in 2006. During the third quarter of 2007, production expenses averaged \$13.13/boe, compared to \$8.58/boe over the same period in 2006. For the second quarter, production expenses averaged \$12.69/boe. The large increase in third quarter costs on a boe basis was mainly due to a significant fixed component of production expenses and the combination of substantially reduced production volumes in the third quarter. Also, included in the third quarter was approximately \$1.8 million (\$1.37/boe) of costs related to prior periods; excluding this impact, production expenses for the quarter would have been approximately \$11.76/boe.

For the nine month period ended September 30, 2007, production expenses averaged \$11.46/boe, compared to \$8.93/boe. Production expenses for the nine month period ended September 30, 2007 include approximately \$3.7 million (\$0.82/boe) of costs related to prior periods, including primarily additional costs recognized in the second quarter of 2007; excluding this impact, production expenses for the year-to-date period would have been approximately \$10.64/boe.

Production expenses are expected to increase in the fourth quarter of 2007 as additional natural gas input costs are required to operate the Kerrobert SAGD facility after startup. To mitigate expected increases in natural gas fuel costs through the first quarter of 2008, True has negotiated two fixed price fuel purchase contracts as follows: 1) 1,000 GJ/day of natural gas at \$4.65/GJ for the month of October 2007; and 2) 2,000 GJ/day of natural gas for \$6.415/GJ for the months of November 2007 to March 2008.

Production Expenses, by Commodity Type

(\$000s, except where noted)	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Light crude oil, condensate and NGLs \$/bbl	1,524 17.31	852 8.48	6,292 12.45	5,221 12.96
Heavy oil \$/bbl	4,067 14.73	3,453 8.23	15,084 15.93	7,354 8.61
Natural gas \$/mcf	11,433 2.04	6,153 1.47	30,398 1.65	16,371 1.37
Total \$/boe	17,024 13.13	10,458 8.58	51,774 11.46	28,946 8.93

Transportation

Transportation costs are expected to be approximately 2 to 3% of gross revenues for the 2007 year. For the third quarter of 2007, transportation costs averaged 3% as anticipated.

Operating Netback

For the third quarter of 2007, corporate field operating netback (before hedging) was \$15.76/boe compared to \$23.66/boe in 2006. This was the result of decreased natural gas and crude oil, condensate and NGL commodity prices, higher operating costs experienced in the current quarter, offset by reduced average royalties. By comparison, corporate field operating netback (before hedging) for the second quarter of 2007 was \$26.79/boe. After including hedging activities, corporate field operating netback for the third quarter was \$16.65/boe compared to \$23.50/boe in 2006.

Field Operating Netback – Corporate (before hedging)

(\$/boe)	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Sales	37.68	44.31	42.87	43.95
Transportation	(1.29)	(1.38)	(1.06)	(1.28)
Royalties	(7.50)	(10.69)	(7.62)	(10.27)
Production expense	(13.13)	(8.58)	(11.46)	(8.93)
Field operating netback	15.76	23.66	22.73	23.47

Field operating netback for natural gas for the third quarter of 2007 decreased 34% to \$2.05/mcf, compared to \$3.12/mcf for 2006, reflecting the weaker natural gas prices experienced in addition to higher production costs, offset by lower royalties. By comparison, the field operating netback for natural gas was \$4.12/mcf for the second quarter of 2007. After including hedging activities, field operating netback for natural gas for the third quarter of 2007 was \$2.67/mcf compared to \$3.12/mcf in 2006.

Field Operating Netback - Natural Gas (before hedging)

(\$/mcf)	Three months ended September 30,		Six months ended September 30,	
	2007	2006	2007	2006
Sales	5.44	6.02	6.82	6.61
Transportation	(0.24)	(0.13)	(0.22)	(0.16)
Royalties	(1.11)	(1.30)	(1.28)	(1.60)
Production expense	(2.04)	(1.47)	(1.65)	(1.37)
Field operating netback	2.05	3.12	3.67	3.48

Field operating netback for crude oil and NGLs averaged \$24.71/bbl for the third quarter of 2007, down 22% compared to \$30.32/bbl for 2006, compared to a 9% decrease in the crude oil and NGLs sales price. After including hedging activities, field operating netback for crude oil and NGLs for the third quarter of 2007 was \$18.24/boe compared to \$29.96/boe in 2006.

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

(\$/bbl)	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Sales	50.54	55.35	46.94	50.71
Transportation	(0.89)	(2.17)	(0.44)	(1.77)
Royalties	(9.59)	(14.58)	(7.56)	(11.30)
Production expense	(15.35)	(8.28)	(14.73)	(10.01)
Field operating netback	24.71	30.32	24.21	27.63

General and Administrative

Net general and administrative (“G&A”) expenses for the three and nine months ended September 30, 2007 were \$4.2 million and \$13.5 million, respectively, compared to \$2.6 million and \$9.0 million, respectively, for the same periods in 2006.

The increase in the G&A expense for the respective 2007 periods as compared to the same periods in 2006 is consistent with the increase in staffing levels, higher compensation and other administrative costs as a result of two acquisitions completed in 2006. G&A in the third quarter of 2007 includes severance costs of approximately \$0.4 million. On a per boe basis, G&A expenses were \$3.26/boe for the third quarter compared to \$2.78/boe for the second quarter of 2007. The increase in G&A on a per boe basis is consistent with reduced sales volumes experienced during the third quarter.

General and Administrative Expenses

(\$000s, except where noted)	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Gross expenses	5,551	3,500	17,833	12,430
Capitalized	(863)	(562)	(2,677)	(1,984)
Recoveries	(456)	(355)	(1,688)	(1,456)
Net expenses	4,232	2,583	13,468	8,990
Net expenses, per unit (\$/boe)	3.26	2.12	2.98	2.77

G&A expenses for the nine month period ended September 30, 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 \$4.4 million of interest and financing charges in the three months ended September 30, 2007 compared to \$2.8 million in the same period of 2006. For the nine months ended September 30, 2007, interest and financing charges were \$13.5 million compared to \$6.4 million in the same period in 2006. The increase in interest and financing charges for both the three and nine month periods ended September 30, 2007 compared to the same periods in 2006 is consistent with the increase in bank debt. True’s net debt at September 30, 2007 of \$233.9 million includes the \$79.0 million liability portion of convertible debentures, \$159.2 million of bank debt and net of the balance of working capital.

Interest and Financing Charges

(\$000s, except where noted)	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Interest and financing charges	4,422	2,793	13,542	6,403
Interest and financing charges (\$/boe)	3.40	2.29	3.00	1.97
Net debt including convertible debentures at quarter end	233,853	245,759	233,853	245,759
Debt to periods cash flow from operations ratio annualized	3.3x	2.6x	2.1x	3.1x
Net debt excluding convertible debentures at quarter end	154,832	164,380	154,832	164,380
Debt to periods cash flow from operations ratio annualized	2.2x	1.8x	1.4x	2.1x

Unit-Based Compensation

Non-cash unit-based compensation expense for the three and nine months ended September 30, 2007 was \$0.9 million and \$3.3 million, respectively, compared to \$1.8 million and \$4.9 million in 2006, respectively. The decrease in the 2007 expense for both periods reflects reduced incentive rights being granted in the first nine months of 2007, compared to the same period in 2006, in addition to a reduction in the estimated weighted average fair value of incentive rights granted for more recent options.

Capital Expenditures

True invested \$11.3 million on exploration and development activities during the third quarter of 2007, compared to \$33.4 million in the same period in 2006. Following the execution of True's extensive Q1 2007 drilling program of 34 (24.0 net) wells, the main focus for the second and third quarters of 2007 was on completions and tie-ins of first quarter drills and further upgrades to the Kerrobert SAGD facility. During the third quarter of 2007, True successfully drilled 2 (1.5 net) heavy oil wells in the Mantario area in Saskatchewan.

Capital Expenditures

(\$000s)	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Lease acquisitions and retention	358	1,694	1,860	4,226
Geological and geophysical	263	736	3,727	1,597
Drilling and completion costs	8,798	19,055	57,718	49,062
Facilities and equipment	1,892	11,953	9,350	18,382
Exploration and development	11,311	33,438	72,655	73,267
Corporate and property acquisitions	139	12,728	1,493	12,920
Total capital expenditures – cash	11,450	46,166	74,148	86,187
Property dispositions – cash	(3,806)	-	(31,275)	(24,514)
Total net capital expenditures – cash	7,644	46,166	42,873	61,673
Corporate acquisitions – non-cash	-	435,346	-	482,875
Other – non-cash ⁽¹⁾	116	1,465	(197)	1,892
Corporate acquisitions and other	116	436,811	(197)	484,767
Total capital expenditures	7,760	482,977	42,676	546,440

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

True holds an extensive land base. At September 30, 2007, True has approximately 557,000 net undeveloped acres of land of its total developed and undeveloped net acreage position of 963,000 net acres in Saskatchewan, Alberta, and British Columbia.

Dispositions during the first nine months of 2007 consist of six separate oil and gas property sales involving areas outside of the Trust's core areas for future development, including three additional minor northern Alberta property sales which closed in the third quarter. During the third quarter of 2007, True closed on the Shane property sale in July and the Monias and Rainbow properties in August. The net proceeds received on these property sales after adjustments was an aggregate of \$3.8 million.

The Trust continues to evaluate further opportunities with its divestiture program.

At the end of the third quarter of 2007, the Trust had committed to drill a total of 2 wells in Alberta with varying commitment dates up to the end of the first quarter of 2008 pursuant to various farm-in agreements with oil and gas companies. True expects to satisfy these various drilling commitments at an estimated cost for True's interest of approximately \$2.8 million.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion (site restoration) expense for the third quarter of 2007 was \$38.9 million, compared to the \$29.1 million for the same period in 2006, reflecting the acquisition of 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 third quarter of 2007 of \$29.99/boe was higher than \$29.11/boe DD&A rate for the second quarter of 2007, which reflects the adjustment to reserves after 2007 property dispositions.

For the nine month period ended September 30, 2007, True has excluded from the depletion calculation \$38.4 million for undeveloped land and \$46.9 million for estimated salvage.

Depletion, Depreciation and Accretion Costs

(\$000s, except where noted)	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Depletion and Depreciation	38,347	28,763	130,116	85,057
Accretion	543	297	1,581	715
Total	38,890	29,060	131,697	85,802
Per unit (\$/boe)	29.99	23.84	29.16	26.46

The Trust's independent reserve report effective December 31, 2006 is summarized in its Annual Information Form which can be found at 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 September 30, 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.

The ceiling test calculation will be updated on an annual basis based upon the latest available data, including but not limited to an updated external reserve engineering report which incorporates a full evaluation of reserves and the latest commodity pricing deck. Estimating reserves is very complex,

requiring many judgments based on available geological, geophysical, engineering and economic data. Changes in these judgments could have a material impact on the estimated reserves. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available, and as the economic environment changes. Changes in these judgments and estimates could have a material impact on the calculation of the ceiling test.

At September 30, 2007, the Trust calculated the ceiling test using weighted average prices of \$42.15/bbl for heavy oil, \$68.65/bbl for light and medium gravity oil, and \$42.62/bbl for NGLs, and \$7.57/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 as special meeting costs within the statement of income for the nine month period ended September 30, 2007.

Asset Retirement Obligations

As at September 30, 2007, the Trust has recorded an Asset Retirement Obligation ("ARO") of \$27.7 million, compared to \$25.5 million at September 30, 2006, for future abandonment and reclamation of the Trust's properties. For the nine month period ended September 30, 2007, the ARO increased by \$1.1 million total as a result of accretion expense of \$1.6 million, and \$0.4 million net changes in estimates and liabilities incurred on development activities, offset by \$0.9 million of liabilities released on dispositions.

Income Taxes

For the first nine months of 2007, the Trust has recorded capital tax expense of \$1.5 million compared to \$2.4 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. 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 Trust's assets and liabilities. For the first nine months of 2007, the Trust recognized a future income tax recovery of \$30.0 million compared to a recovery of \$49.0 million in the same period in 2006. The larger recovery for the 2006 period was primarily reflective of more significant enacted tax rate reductions 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 addition, on June 12, 2007, the federal government further reduced the general corporate tax rate by 0.5 percent starting 2011.

Under our current structure, the operating entities make interest and royalty payments to the Trust, which transfers taxable income to the Trust to eliminate income subject to corporate and other income taxes in the operating entities. With the new legislation, such amounts transferred to the Trust could be taxable beginning in 2011 as distributions will no longer be deductible for income tax purposes. At that time, True could claim tax pools in its operating companies, reduce the income transferred to the Trust, and pay all or a portion of distributions as a return of capital basis. Until 2011, under the terms of its Trust indenture, the Trust is required to distribute amounts equal to at least its taxable income. In the event that the Trust has undistributed taxable income in a taxation year (prior to 2011), an additional special taxable distribution, subject to certain withholding taxes, would be required by the terms of its trust indenture.

The estimate of future taxes is based on the current tax status of the Trust. Future events, which could materially affect future income taxes such as acquisitions and dispositions and modifications to the distribution policy, are not reflected under Canadian GAAP until the events occur and the related legal requirements have been fulfilled. As a result, future changes to the tax legislation could lead to a material change in the recorded amount of future income taxes.

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

Enactment of the Tax on Income Trusts

On June 12, 2007, the legislation implementing the new tax (the "SIFT tax") on publicly traded income trusts and limited partnerships, referred to as "Specified investment flow-through" ("SIFTs") entities (Bill C-52) received third reading in the House of Commons and on June 22, 2007, Bill C-52 received Royal assent. As a result, the tax was considered to be enacted for accounting purposes in June 2007, which resulted in a \$1.2 million future income tax recovery amount being recorded to reflect current temporary differences between the book and tax basis of assets and liabilities expected to be remaining in the Trust in 2011. The SIFT tax announcement and the related future income tax recovery did not affect cash flow or distributions and is not expected to affect distribution policies until 2011 at the earliest.

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

Under the SIFT tax, distributions will not be deductible for income tax purposes by SIFTs in 2011 and thereafter and any trust level taxable income will be taxed at an approximate of the corporate income tax rate. The resultant distributions will be considered taxable dividends to unitholders, generally eligible for the dividend tax credit. Distributions representing a return of capital will continue to be an adjustment to a unitholder's adjusted cost base of trust units.

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

- If structural or other similar changes are not made, the after-tax distribution yield in 2011 to taxable Canadian investors will remain approximately the same, however, the distribution yield in 2011 to tax-deferred Canadian investors (RRSPs, RRIFs, pension plans, etc.) and foreign investors would fall by an estimated 31.5 percent and 26.5 percent, respectively;

- A portion of True's cash flow could be allocated to the payment of the SIFT tax, or other forms of tax, and would not be available for distribution or re-investment;
- True could convert to a corporate structure to facilitate investing a higher proportion or all of its cash flow in exploration and development projects. Such a conversion and change to capital programs could result in a significant reduction to or elimination of distributions and/or dividends;
- True might determine that it is more economic to remain in the trust structure, at least for a period of time, and shelter its taxable income using tax pools and pay all or a portion of its distributions on a return of capital basis, likely at a lower payout ratio. Further, as the SIFT tax rate exceeds the corporate income tax rate that would be applicable to True, some corporate tax might be paid resulting in all or a portion of distributions being paid on a return of capital basis at a lower payout ratio.

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

The table below, provided by the Government of Canada in a backgrounder accompanying its October 31, 2006 announcement, shows a simplified comparison of the effects of the changes to investor tax rates in 2011:

Investor	Current System		Proposed System	
	Income portion of trust distributions	Large corporation (dividend)	Income portion of trust distributions	Large corporation (dividend)
Taxable Canadian individuals (1)	46%	46%	45.5%	45.5%
Canadian tax-exempt investors	0%	32%	31.5%	31.5%
Taxable U.S. investors (2)	15%	42%	41.5%	41.5%

(1) All rates in the table are as of 2011, and include both entity- and investor-level tax (as applicable). Rates for "taxable Canadian individuals" assume that top personal income tax rates apply and that provincial governments increase their dividend tax credit for dividends of large corporations.

(2) Canadian taxes only. U.S. tax will also apply in most cases, net of any foreign tax credits.

As at September 30, 2007, the operating subsidiaries and the Trust itself have a total future income tax liability balance of \$94.0 million. Canadian GAAP requires that a future income tax liability be recorded when the book value of assets exceeds the balance of tax pools.

At September 30, 2007 the Trust and operating subsidiaries of the Trust had approximately \$501 million, net of partnership deferrals, in tax pools available for deduction against future income as follows:

(\$000s)	Trust	Operating subsidiaries	Total
Intangible resource pools (net of partnership deferrals)	15,000	309,000	324,000
Undepreciated capital cost	-	137,000	137,000
Loss carryforwards (expire through 2026)	-	29,000	29,000
Unit issue costs	6,000	5,000	11,000
	21,000	480,000	501,000

Distributions

Trust unitholders who held their trust units throughout the first nine months of 2007 received distributions of \$0.72 per unit. For the nine month period ended September 30, 2007 the Trust declared \$54.4 million in total distributions as follows:

<i>(\$000s, except per unit amount)</i> Nine month period ended September 30, 2007	Distribution Per Unit	Total
Distributions declared	\$ 0.72	\$ 54,374

Distribution Paid History ⁽¹⁾

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

Calendar Year	Distributions per unit	Taxable Portion	Return of Capital
2005 (two months) ⁽²⁾	\$ 0.480	\$ 0.456	\$ 0.024
2006 ⁽³⁾	2.640	2.033	0.607
Cumulative to Dec. 31, 2006	\$ 3.120	\$ 2.489	\$ 0.631
2007 year to date	0.720	⁽³⁾	⁽³⁾
Cumulative to Sept. 30, 2007	\$ 3.840		

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

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

⁽³⁾ The majority 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	May 31, 2007	June 15, 2007	0.08
June 27, 2007	June 29, 2007	July 16, 2007	0.08
July 27, 2007	July 31, 2007	August 15, 2007	0.08
August 29, 2007	August 31, 2007	September 17, 2007	0.08
September 26, 2007	September 28, 2007	October 15, 2007	0.08
October 29, 2007	October 31, 2007	November 15, 2007	0.08
November 28, 2007 ⁽¹⁾	November 30, 2007	December 17, 2007	0.08 ⁽²⁾
December 27, 2007 ⁽¹⁾	December 31, 2007	January 15, 2008	0.08 ⁽²⁾

- (1) Anticipated ex-distribution dates for November and December. These dates are subject to change and/or confirmation by the Toronto Stock Exchange and will be confirmed by monthly press release.
- (2) Subject to confirmation, the Management and Board of the Trust continuously assess 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 nine months of 2007, the distributions were funded directly from cash flows from operating activities.

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.

In the second and third quarters of 2007, monthly distributions of \$0.08 per unit were declared and paid. Further, the Board has announced it has set a distribution policy for the fourth 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.

Foreign Ownership Update

Based on information from Trust records and information provided by intermediaries holding Trust units for others, The Trust estimates that, as of October 19, 2007 approximately 29 percent of 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 September 30, 2007 was \$233.9 million, representing \$159.2 million outstanding on the credit facility, \$79.0 million in convertible debentures (liability component) and net of the balance of working capital.

During the nine month period ended September 30, 2007, the Trust has reduced its net debt by approximately \$42.0 million. As at September 30, 2007, working capital was \$4.4 million compared to a working capital deficiency of \$36.4 million at December 31, 2006. This was achieved as a result of many factors including the proceeds received from the Trust's May 31, 2007 equity offering, proceeds received from six property dispositions, maintaining sustainable distributions compared to cash flows from operations for the year and capital expenditure requirements in the period and continued execution of the Trust's hedging program.

The current credit facility consists of a \$15 million demand operating facility provided by one Canadian bank and a \$175 million extendible revolving term credit facility syndicated by two Canadian chartered banks, a U.S. bank, a Canadian financial institution and one institutional lender. The revolving period on the revolving term credit facility ends on June 29, 2008, unless extended for a further 364 day period. Should the facilities not be renewed they convert to 366 day non-revolving term facilities on the renewal date. The borrowing base was renewed effective August 31, 2007 and is currently scheduled for renewal on March 31, 2008. Further details of the credit facilities are disclosed in note 7 of the consolidated

financial statements. As at September 30, 2007, there is approximately \$31 million undrawn under these lending facilities.

Management expects to be able to fund its capital expenditure program for the remainder of 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 are expected to 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 October 31, 2007 the Trust had outstanding a total of 6,029,497 incentive units exercisable at an average exercise price of \$10.82 per unit, 390,813 exchangeable shares (convertible, as at October 31, 2007 into an aggregate of 321,647 trust units, subject to further adjustments based on distributions made on trust units) and 79,715,595 trust units.

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

Business Prospects and 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 implement a steam assisted gravity drainage ("SAGD") project. Execution of the Kerrobert SAGD project is on track. During the first quarter of 2007, True completed its Phase 1 drilling campaign consisting of five cold producers and four thermal wells. SAGD facility upgrades continued throughout the second and third quarters of 2007. The steam injection commenced in late September and after an initial "warm-up" phase the four thermal production wells are

now configured for fluid production. Oil production from these thermal wells is expected to ramp up during the remainder of the fourth quarter and reach the anticipated peak rates of approximately 500 bbls/d per well pair late in 2007 or early in the first quarter of 2008, thereby increasing total heavy oil production in the Kerrobert area to approximately 4,000 bbls/d.

Based upon field estimates, current production is approximately 15,500 boe/d and increasing. Further focus on recompletion, optimization, and tie-in potential, in conjunction with response from the Kerrobert SAGD expansion start-up is anticipated to provide significant production growth prior to the end of the 2007 year. The Trust is anticipating 2007 annual average volumes of approximately 16,500 boe/d, weighted approximately 65% towards natural gas.

True further anticipates the US\$/Cdn.\$ exchange rate to average 1.00 through remainder of the 2007 year.

The Trust continues to maintain a large undeveloped land base of approximately 0.8 million (0.6 million net) acres and has identified a multi-year drilling inventory of over 375 net locations.

Gas prices continue to show volatility with lack of cold weather and the current supply/demand imbalance. Given the current natural gas price outlook, coming into the winter drilling season, True plans to reduce its first quarter 2008 winter drilling activity compared to the first quarter of 2007. True's first quarter 2008 capital program will not exceed \$10 million which compares to a front end loaded 2007 capital program of approximately \$50 million in first quarter 2007. True will continue to take a balanced approach to the priority use of cash flow between level of distributions and size of its 2008 capital program. Given the nature of True's lands and their inherent advantage of year round access, True will spread its 2008 capital program more evenly through the full year of 2008 to take advantage of reduced service costs during non-peak times. True will focus on increasing its farm-out activity in non-core areas. If the 2008 outlook for commodity prices improves, True would plan to increase its capital spending in third and fourth quarters of 2008.

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.

In Alberta, the reduction emission guidelines outlined the Climate Change and Emissions Management Amendment Act (the "Act") came into effect July 1, 2007. Alberta facilities emitting more than 100,000

tonnes of greenhouse gases a year must reduce their emissions intensity by 12 per cent. Industries have three options to choose from in order to meet the reduction requirements outlined in the Act, and these are: (a) by making improvement to operations that result in reductions; (b) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emissions; or (c) by contributing to the Climate Change and Emissions Management Fund. Industries can either choose one of these options or a combination thereof. On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan"), also known as ecoACTION which includes the Regulatory Framework for Air Emissions. This Action Plan covers not-only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on the Trust and its operations and financial condition.

Announcement on the Alberta Royalty and Tax Regime

On October 25, 2007, the Alberta Government released *The New Royalty Framework* which summarizes the government's decision on Alberta's new royalty regime pertaining to oil and gas resources, including oil sands, conventional oil and gas and coalbed methane. This was in response to recommendations recently put forth by an Alberta Royalty Review Panel. This new royalty regime will take effect on January 1, 2009. The actual impact will be determined based on the actual legislation as well as production rates, drilling depths, commodity prices, product mix and the percentage of production from Alberta after January 1, 2009.

The proposed royalty changes are very sensitive to production rate and natural gas prices. The majority of True's current Alberta wells are in the 500m to 1000m depth range and typically produce at lower rates. Based on publicly available information in respect of the New Royalty Framework, and by re-running True's reserves evaluated at December 31, 2006 and using the same assumptions including pricing (an average of consultants forecast prices as at January 1, 2007), True estimates that the proposed royalty rates would result in a positive revision to True's net present value of future net revenues from reserves, as at December 31, 2006, (based upon a 10% discount factor) of approximately 0.8% and a 0.8% increase in net reserves (working interest and royalty interests in reserves after deducting royalty obligations), as at December 31, 2006. Based on the foregoing, the New Royalty Framework would result in a positive revision to True's net asset value, as at December 31, 2006, of approximately 1%.

True is continuing to assess the impact on its ongoing Alberta operations. While the Trust cannot determine the full potential impact of these changes to the royalty rate on its operations at this time, it is anticipated that the impact will not be material to True given True's current weighting of Alberta production to total corporate production, as well as True's production in Alberta being primarily in shallow natural gas wells.

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 September 30, 2007. Except as described in Note 3 of the attached unaudited interim consolidated financial statements, there were no changes in accounting policies for the nine month period ended September 30, 2007.

In September 2007, the Accounting Standards Board (“AcSB”) issued a bulletin relating to the transition to International Financial Reporting Standards (“IFRS”) from Canadian GAAP and based on work undertaken to date, no significant impediments to adopting IFRS by the proposed transition date have been identified. True is monitoring industry discussion regarding the implications of the replacement of the CICA’s Accounting Guideline 16 with IFRS 6, which is expected to have major implications for True’s full cost accounting policies. The AcSB expects to be in a position to confirm by March 31, 2008 whether the transition date for adopting IFRS will be January 1, 2011.

Legal, Environmental Remediation and Other Contingent Matters

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

Controls and Procedures

Disclosure Controls and Procedures

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 and interim 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 September 30, 2007, that has materially affected, or are reasonably likely to materially affect, the Trust’s internal control over financial reporting.

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

Standardized Distributable Cash

The Canadian Securities Administrators recently revised and re-issued National Policy 41-201 “Income Trusts and Other Indirect Offerings”, which includes disclosures regarding distributable cash for Income Trusts. Further, the Canadian Institute of Chartered Accountants (“CICA”) issued the Interpretive Release “Standardized Distributable Cash in Income Trusts and Other Flow-Through Entities: Guidance on Preparation and Disclosure” (the “Release”) in July 2007, which is required for the third quarter of 2007. In the new guidance, sustainability concepts are discussed and standardized distributable cash is defined

as cash flow from operating activities less adjustments for productive capacity maintenance, long-term unfunded contractual obligations and the effect of any foreseeable financing matters, related to debt covenants, which could impair True's ability to pay distributions or maintain productive capacity. This Management Discussion and Analysis is in all material respects in accordance with the recommendations provided in CICA's Release.

<i>(\$000s, except per indicators)</i>	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Net income (loss)	(17,003)	1,652	(23,833)	17,154
Cash flow from operating activities	14,880	43,509	59,816	62,981
Productive capacity maintenance ⁽¹⁾	(11,331)	(33,438)	(72,655)	(73,267)
Standardized distributable cash	3,549	10,071	(12,839)	(10,286)
Proceeds on sale of property, plant and equipment	3,806	-	31,275	24,514
Funding from DRIP	-	20,760	-	35,824
Net proceeds from issue of trust units	(11)	-	54,375	-
Proceeds from issue of convertible debentures, net of issue costs	-	-	-	82,227
Bank borrowings (debt repayment) and working capital changes and other	11,788	6,015	(18,437)	(41,512)
Cash Distributions declared	19,132	36,846	54,374	90,767
Accumulated distributions, beginning of period	176,958	71,282	141,716	17,361
Accumulated distributions, end of period	196,090	108,128	196,090	108,128
Standardized distributable cash per unit - basic	\$0.04	\$0.15	(\$0.16)	(\$0.14)
Standardized distributable cash per unit – diluted	\$0.04	\$0.13	(\$0.14)	(\$0.13)
Standardized distributable cash payout ratio ⁽²⁾	5.39	3.66	N/A	N/A
Distributions declared per unit	\$0.24	\$0.72	\$0.72	\$2.16
Excess (shortfall) of net income over cash distributions declared	(36,135)	(35,194)	(78,207)	(73,613)
Excess (shortfall) of cash flow from operating activities over cash distributions declared	(4,252)	6,663	5,442	(27,786)

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

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

True strives to fund both distributions and maintenance capital primarily from cash flow. True's 2007 capital budget was initially set at approximately 40% to 50% of annual cash flow. Property dispositions, equity issues or additional borrowings may be required from time to time to fund a portion of the distributions and/or capital expenditures to maintain or increase productive capacity may be required based on forecast levels of cash flow, capital efficiency and debt levels.

Productive capacity is the amount of capital funds required in a period for an enterprise to maintain its ability to generate future cash flow from operating activities at a constant level. As commodity prices can be volatile and short-term variations in production levels are often experienced in the oil and gas industry, True defines production capacity as production on a barrel of oil equivalent basis. A quantifiable measure for these short-term variations is not objectively determinable or verifiable due to various factors including the inability to distinguish natural production declines from the effect of production additions resulting from capital and optimization programs, and the effect of temporary production interruptions. As a result, the adjustment for productive capacity maintenance in True's calculation of standardized distributable cash is

True's capital expenditures excluding the cost of any asset acquisition, corporate asset acquisitions or proceeds of any asset disposition. True believes that its capital programs based on 40% to 50% of forecast cash flow including its current view of True's assets and opportunities and True's outlook for commodity prices and industry conditions in the medium term, should be sufficient to maintain True's productive capacity in the medium term. True sets its hurdle rates for evaluating potential development and optimization projects according to these parameters. Due to the risks inherent in the oil and natural gas industry, particularly True's exploration and development activities and inherent variations in commodity prices, there can be no assurance that capital programs, whether limited to excess of cash flow over distributions or not, will be sufficient to maintain or increase True's production levels or cash flow from operating activities. True's capital expenditures and production can be impacted by the timing of the capital program and spring break up associated with certain operating areas of its properties. As True strives to maintain sufficient credit facilities and appropriate levels of bank debt, this seasonality is not expected to influence True's distribution policies.

True's calculation of standardized distributable cash has no adjustment for long-term unfunded contractual obligations. True's only long-term unfunded contractual obligation at this time is for asset retirement obligations. True's abandonment obligations are being funded on an annual basis. Our maintenance capital amount includes an amount for abandonment expenditures incurred during the period. True currently has no financing restrictions on distributions arising from compliance with its debt covenants. True regularly monitors its current forecast debt levels to ensure debt covenants are not exceeded.

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

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

<i>(\$000s, except per indicators)</i>	To September 30, 2007
Cumulative distributable cash from operations ⁽¹⁾	15,590
Proceeds on sale of property, plant and equipment	55,789
Funding from DRIP	42,909
Net proceeds from issue of trust units	54,375
Proceeds from issue of convertible debentures, net of issue costs	82,227
Bank borrowings (debt repayment) and working capital changes and other	(54,800)
Cumulative cash distributions declared ⁽¹⁾	196,090
Standardized distributable cash payout ratio ⁽²⁾	12.58

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

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

Sensitivity Analysis

The table below shows sensitivities to cash flow as a result of product price and operational changes. This is based on actual prices received for the three month period ended September 30, 2007 and average production volumes of 14,096 boe/d during that period, as well as the same level of debt outstanding at September 30, 2007. Diluted weighted average trust units is based upon the third 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	1,300	0.02
Change of \$0.10/ mcf	1,800	0.02
Change of US \$0.01 Cdn/ US exchange rate	800	0.01
Change in prime of 1%	1,600	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 third quarter of 2007.

2007 – Quarter ended (unaudited) (\$000s, except per unit amounts)	March 31	June 30	Sept. 30
Revenues before royalties and hedging	71,196	74,991	50,547
Cash flow from operations ⁽¹⁾	29,988	34,192	17,478
Cash flow from operations per unit ⁽¹⁾			
Basic	\$0.43	\$0.47	\$0.22
Diluted	\$0.42	\$0.45	\$0.22
Net income (loss)	(8,571)	1,741	(17,003)
Net income (loss) per unit			
Basic	\$(0.12)	\$0.02	\$(0.21)
Diluted	\$(0.12)	\$0.02	\$(0.21)
Net capital expenditures (cash)	28,103	7,126	7,644
Distributions declared	16,866	18,376	19,132
Distributions per unit	\$0.24	\$0.24	\$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 ⁽¹⁾	18,995	16,386	23,225	31,785
Cash flow from operations per unit ⁽¹⁾				
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) ⁽²⁾ (\$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 ⁽¹⁾	10,732	18,013	25,500	32,892
Cash flow from operations per unit ⁽¹⁾				
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 ⁽²⁾	-	-	-	\$0.48

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

⁽²⁾ 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 second quarter of 2007 to the third 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 Oil & Gas, Inc. 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 Energy Trust 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. Future 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 September 30 and December 31 (unaudited)

(\$000s)	2007	2006
ASSETS		
Current assets		
Accounts receivable	\$ 55,619	\$ 73,199
Deposits and prepaid expenses	5,691	7,928
Capital taxes recoverable	732	-
Commodity contract asset (note 19)	3,295	-
	<u>65,337</u>	<u>81,127</u>
Property, plant and equipment (note 6)	844,539	931,979
Deferred financing charges (note 8)	-	3,552
Total assets	<u>\$ 909,876</u>	<u>\$ 1,016,658</u>
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	\$ 51,982	\$ 107,431
Distribution payable to unitholders	6,377	8,433
Capital taxes payable	-	1,513
Current portion of obligations under capital lease	-	111
Commodity contract liability (note 19)	2,598	-
	<u>60,957</u>	<u>117,488</u>
Long-term debt (note 7)	159,212	157,904
Convertible debentures (note 8)	79,021	81,551
Asset retirement obligations (note 9)	27,708	26,605
Future income taxes (note 14)	93,975	123,861
Total liabilities	<u>420,873</u>	<u>507,409</u>
NON-CONTROLLING INTEREST		
Exchangeable shares of subsidiary (note 10)	3,928	4,153
UNITHOLDERS' EQUITY		
Unitholders' capital (note 11)	931,410	876,904
Equity component of convertible debentures (note 8)	5,119	5,119
Contributed surplus (note 12)	16,355	12,818
Deficit	(467,855)	(389,745)
Accumulated other comprehensive income	46	-
Total unitholders' equity	<u>485,075</u>	<u>505,096</u>
Total liabilities and unitholders' equity	<u>\$ 909,876</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 and nine months ended September 30 (unaudited)

(\$000s)	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
REVENUES				
Petroleum and natural gas sales	\$ 50,547	\$ 54,263	\$ 196,734	\$ 143,663
Royalties	(9,727)	(13,025)	(34,422)	(33,323)
Gain (loss) on commodity contracts (note 19)	1,156	(188)	7,670	(461)
	41,976	41,050	169,982	109,879
EXPENSES				
Production	17,024	10,458	51,774	28,946
Transportation	1,671	1,682	4,791	4,145
General and administrative	4,232	2,583	13,468	8,990
Interest and financing charges	4,422	2,793	13,542	6,403
Unit-based compensation (notes 11 and 12)	869	1,824	3,256	4,875
Depletion, depreciation and accretion	38,890	29,060	131,697	85,802
Special meeting costs (note 15)	-	-	3,805	-
	67,108	48,400	222,333	139,161
LOSS BEFORE TAXES	(25,132)	(7,350)	(52,351)	(29,282)
TAXES (note 14)				
Capital taxes	442	860	1,533	2,384
Future income tax recovery	(8,501)	(9,949)	(29,957)	(49,043)
	(8,059)	(9,089)	(28,424)	(46,659)
NET INCOME (LOSS) BEFORE NON-CONTROLLING INTEREST	(17,073)	1,739	(23,927)	17,377
Non-controlling interest (note 10)	(70)	87	(94)	223
NET INCOME (LOSS)	(17,003)	1,652	(23,833)	17,154
Net changes in cash flow hedges (net of tax of \$0.06 million and \$1.8 million, respectively)	(138)	-	(3,703)	-
COMPREHENSIVE INCOME (LOSS)	\$ (17,141)	\$ 1,652	\$ (27,536)	\$ 17,154
Net income (loss) per trust unit				
Basic	\$(0.21)	\$0.04	\$(0.32)	\$0.43
Diluted	\$(0.21)	\$0.04	\$(0.32)	\$0.43

See accompanying selected notes to the consolidated financial statements.

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

For the three and nine months ended September 30 (unaudited)

(\$000s)	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
UNITHOLDERS' CAPITAL				
Balance, beginning of period	\$ 931,336	\$ 506,377	\$ 876,904	\$ 418,968
Issued for cash (net of issue costs of \$3.1 million)	(11)	-	54,375	-
Issued to acquire Prairie Schooner (net of issue costs of \$1.6 million)	-	341,089	-	341,089
Issued to acquire Shellbridge (net of issue costs of \$0.6 million)	-	-	-	67,668
Exchangeable shares converted	85	-	131	4,677
Units issued pursuant to DRIP	-	15,239	-	30,303
Units to be issued pursuant to DRIP	-	5,521	-	5,521
Balance, end of period	931,410	868,226	931,410	868,226
EQUITY COMPONENT OF CONVERTIBLE DEBENTURES				
Balance, beginning of period	5,119	5,119	5,119	-
Conversion feature on convertible debentures issued	-	-	-	5,119
Balance, end of period	5,119	5,119	5,119	5,119
CONTRIBUTED SURPLUS				
Balance, beginning of period	15,407	8,724	12,818	5,127
Unit-based compensation expense (note 12)	948	2,137	3,537	5,734
Balance, end of period	16,355	10,861	16,355	10,861
DEFICIT				
Balance, beginning of period	(431,720)	(70,245)	(389,745)	(31,826)
Net income (loss)	(17,003)	1,652	(23,833)	17,154
Impact of changes in accounting policy for financial instruments on January 1, 2007 (net of tax of \$0.05 million) (note 3)	-	-	97	-
Distributions declared	(19,132)	(36,846)	(54,374)	(90,767)
Balance, end of period	(467,855)	(105,439)	(467,855)	(105,439)
ACCUMULATED OTHER COMPREHENSIVE INCOME				
Balance, beginning of period	184	-	-	-
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 \$0.06 million and \$1.8 million, respectively)	(138)	-	(3,703)	-
Balance, end of period	46	-	46	-
TOTAL UNITHOLDERS' EQUITY	\$ 485,075	\$ 778,767	\$ 485,075	\$ 778,767

See accompanying selected notes to the consolidated financial statements.

TRUE ENERGY TRUST
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the three and nine months ended September 30 (unaudited)

(\$000s)	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Cash provided by (used in):				
CASH FLOW FROM OPERATING ACTIVITIES				
Net income (loss)	\$ (17,003)	\$ 1,652	\$ (23,833)	\$ 17,154
Items not involving cash:				
Non-controlling interest (note 10)	(70)	87	(94)	223
Depletion, depreciation and accretion	38,890	29,060	131,697	85,802
Unit-based compensation (note 12)	869	1,824	3,256	4,875
Unrealized loss (gain) on commodity contracts (note 19)	2,908	-	(580)	-
Amortization of deferred financing charges (note 8)	-	201	-	236
Accretion on convertible debentures (note 8)	385	211	1,169	248
Future income taxes (recovery) (note 14)	(8,501)	(9,949)	(29,957)	(49,043)
Capital taxes	-	139	-	(889)
	17,478	23,225	81,658	58,606
Change in non-cash working capital (note 13)	(2,598)	20,284	(21,842)	4,375
	14,880	43,509	59,816	62,981
CASH FLOW FROM (USED IN) FINANCING ACTIVITIES				
Increase (decrease) in bank debt	17,059	30,285	2,328	(19,246)
Obligations under capital lease	-	(45)	(111)	(143)
Issuance of convertible debentures	-	-	-	86,250
Deferred financing charges	-	34	-	(3,989)
Issue of trust units for cash	-	-	57,523	-
Unit issue costs	(11)	(1,781)	(3,148)	(2,410)
Payment of cash component of distributions	(19,131)	(15,146)	(56,429)	(52,641)
	(2,083)	13,347	163	7,821
Change in non-cash working capital (note 13)	(262)	1,255	(19)	2,148
	(2,345)	14,602	144	9,969
CASH FLOW FROM (USED IN) INVESTING ACTIVITIES				
Additions to property, plant and equipment	(11,450)	(46,166)	(74,148)	(86,187)
Corporate transaction costs	-	(1,563)	-	(2,083)
Proceeds on sale of property, plant and equipment	3,806	-	31,275	24,514
	(7,644)	(47,729)	(42,873)	(63,756)
Change in non-cash working capital (note 13)	(4,891)	(10,382)	(17,087)	(14,412)
	(12,535)	(58,111)	(59,960)	(78,168)
Cash acquired on corporate acquisition (note 5b)	-	-	-	5,218
Change in cash	-	-	-	-
Cash, beginning of period	-	-	-	-
Cash, end of period	\$ -	\$ -	\$ -	\$ -

See accompanying selected notes to the consolidated financial statements.

SELECTED NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

September 30, 2007 and 2006 (unaudited)

1. STRUCTURE OF THE TRUST

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

<i>Increase (decrease) (\$000s)</i>	At January 1, 2007
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>			
		Accumulated depletion and depreciation	
September 30, 2007	Cost		Net book value
Petroleum and natural gas properties	\$1,355,558	\$ 513,809	\$ 841,749
Office furniture and equipment	4,080	1,290	2,790
	<hr/>	<hr/>	<hr/>
	\$1,359,638	\$ 515,099	\$ 844,539
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/>
	\$1,316,962	\$ 384,983	\$ 931,979

The Trust has excluded \$38.4 million for undeveloped land and \$46.9 million for estimated salvage from the depletion calculation during the nine month period ended September 30, 2007.

For the nine month period ended September 30, 2007, the Trust capitalized \$3.1 million of general and administrative expenses and \$0.3 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 \$175 million extendible revolving term credit facility syndicated by two Canadian chartered banks, a U.S. bank, a Canadian financial institution 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 \$0.8 million at September 30, 2007, is now netted against long-term debt and amortized on the effective interest basis.

As at September 30, 2007, there was \$10.0 million outstanding under the operating facility and \$149 million outstanding under the revolving term credit facility. As at September 30, 2007, there is approximately \$31 million undrawn under the facility.

The borrowing base was renewed effective August 31, 2007 and is currently scheduled for renewal on or before March 31, 2008.

The revolving period on the new revolving term credit facility ends on June 28, 2008, 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 September 30, 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 nine month period ended September 30, 2007 and the year ended December 31, 2006:

Convertible debentures

	Number of Debentures	Debt Component (\$000s)	Equity Component (\$000s)
Issued on June 15, 2006	86,250	\$ 81,131	\$ 5,119
Accretion	-	420	-
Balance, December 31, 2006	86,250	81,551	5,119
Impact of change in accounting policy for financial instruments on January 1, 2007 (note 3)	-	(3,699)	-
Accretion	-	1,169	-
Balance, September 30, 2007	86,250	\$ 79,021	\$ 5,119

The following table shows the deferred financing charges activities for the nine month period ended September 30, 2007 and the year ended December 31, 2006:

Deferred financing charges

(\$000s)	September 30, 2007	December 31, 2006
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)	-
Balance, end of period	\$ -	\$ 3,552

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 \$74.6 million which will be incurred between 2007 and 2053. A credit-adjusted risk-free rate of 8 percent and an inflation rate of 2 percent were used to calculate the fair value of the asset retirement obligation.

(\$000s)	September 30, 2007	December 31, 2006
Asset retirement obligation, beginning of period	\$ 26,605	\$ 10,457
Liabilities acquired through corporate acquisitions	-	13,704
Liabilities incurred on development activities	433	1,210
Changes in prior period estimates	16	810
Liabilities released on dispositions	(927)	(641)
Accretion expense	1,581	1,065
Asset retirement obligation, end of period	\$ 27,708	\$ 26,605

10. EXCHANGEABLE SHARES OF SUBSIDIARY

	September 30, 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)	-	(94)	-	(803)
Exchanged for trust units	(12,723)	(131)	(385,022)	(4,753)
Balance, end of period	390,813	\$ 3,928	403,536	\$ 4,153

The exchange ratio is calculated monthly based on the five day weighted average trust unit trading price preceding the monthly effective date, and at September 30, 2007 was 0.80997. 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

	September 30, 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 for cash (net of issue costs of \$3.1 million)	9,430,000	54,375	-	-
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	9,892	131	231,035	4,753
Units issued pursuant to DRIP	-	-	3,574,185	42,608
Issued to acquire property interest	-	-	145,358	1,817
Balance, end of period	79,715,595	\$ 931,410	70,275,703	\$ 876,904

In August 2007, the Trust announced approval of its normal course issuer bid ("NCIB") program to repurchases up to 7.8 million of its outstanding trust units during the period August 28, 2007 through to August 27, 2008, subject to certain conditions. During the three months ended September 30, 2007, no units were repurchased for cancellation. Any excess of the purchase price over carrying amount of the units purchased would be recorded as a reduction of contributed surplus and retained earnings, or conversely an increase to contributed surplus.

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 nine month ended and as at September 30, 2007.

Unit Rights Continuity

	Average Exercise Price ^(a)	Number
Balance, December 31, 2006	\$ 14.18	5,429,831
Granted	\$ 6.13	2,113,500
Forfeited	\$ 13.76	(1,456,499)
Balance, September 30, 2007	\$ 10.93	6,086,832

Unit Rights Outstanding

Exercise Price Before Price Reductions	Exercise Price Net of Reductions	At Sept. 30, 2007	Outstanding		Exercisable	
			Exercise Price Net of Price Reductions ^(b)	Remaining Contractual Life ^(b)	At Sept. 30, 2007	Exercise Price Net of Price Reductions ^(b)
\$ 4.98 - \$ 6.70	\$ 4.95 - \$ 6.32	2,009,000	\$ 5.80	4.6	-	N/A
\$10.58 - \$12.53	\$ 9.46 - \$11.31	1,102,500	\$ 9.73	4.0	284,981	\$ 9.61
\$13.74 - \$14.83	\$11.94 - \$13.11	665,500	\$ 12.37	3.8	215,163	\$ 12.36
\$15.92 - \$16.70	\$13.72 - \$14.47	10,833	\$ 13.98	3.6	56,667	\$ 14.06
\$18.25 - \$20.98	\$15.46 - \$18.41	2,208,999	\$ 15.63	3.1	1,512,653	\$ 15.63
\$ 4.98 - \$20.98	\$ 4.95 - \$18.41	6,086,832	\$ 10.93	3.9	2,067,464	\$ 14.42

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

^(b) 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 nine months ended September 30, 2007, the Trust matched \$0.4 million under the plan.

12. CONTRIBUTED SURPLUS

(\$000s)	September 30, 2007	December 31, 2006
Balance, beginning of period	\$ 12,818	\$ 5,127
Unit-based compensation expense	3,537	7,691
Balance, end of period	\$ 16,355	\$12,818

Unit-based Compensation

During the nine months ended September 30, 2007, the Trust granted 2,113,500 unit incentive rights to employees and directors. During the nine months ended September 30, 2007, the Trust recorded unit-based compensation of \$3.5 million, of which \$0.3 million was capitalized to property, plant and equipment.

The fair values of all incentive rights granted are estimated on the date of grant using the Black-Scholes option-pricing model.

The weighted average fair market value of incentive rights granted during the nine month period ended September 30, 2007 and the assumptions used in their determination are as noted below.

Nine months ended September 30, 2007	
Assumptions:	
Risk free interest rate (%)	4
Expected life (years)	5
Expected volatility (%)	24
Results:	
Weighted average fair value of each incentive right granted	\$ 1.38

13. SUPPLEMENTAL CASH FLOW INFORMATION

Cash Interest and Taxes Paid

(\$000s)	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Cash paid:				
Interest	\$ 3,555	\$ 691	\$ 12,284	\$ 3,565
Taxes (net of refunds)	\$ 219	\$ 657	\$ 3,978	\$ 3,871

Change in Non-cash Working Capital

(\$000s)	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Changes in non-cash working capital items:				
Accounts receivable	\$ 1,313	\$ (24,019)	\$ 17,580	\$ (6,223)
Deposits and prepaid expenses	(1,873)	(4,733)	1,169	(5,332)
Accounts payable and accrued liabilities	(7,547)	39,909	(55,451)	3,666
Capital taxes recoverable/payable	356	-	(2,246)	-
	\$ (7,751)	\$ 11,157	\$ (38,948)	\$ (7,889)
Changes related to operating activities	\$ (2,598)	\$ 20,284	\$ (21,842)	\$ 4,375
Changes related to financing activities	(262)	1,255	(19)	2,148
Changes related to investing activities	(4,891)	(10,382)	(17,087)	(14,412)
	\$ (7,751)	\$ (11,157)	\$ (38,948)	\$ (7,889)

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.

In June 2007, the government legislation implementing the new tax (the "SIFT tax") on publicly traded income trust and limited partnerships (Bill C-52) received third reading in the House of Commons and Royal Assent. For existing income trusts and limited partnerships, the SIFT tax will be effective in 2011 unless certain rules related

to “undue expansion” are not adhered to. As such, the Trust would not be subject to the new measures until the 2011 taxation year provided the Trust continues to meet certain requirements.

As a result of the enactment of the SIFT tax, the Trust recorded a future income tax recovery of \$1.2 million to reflect current temporary differences between the book and tax basis of assets and liabilities expected to be remaining in the Trust in 2011. In accordance with generally accepted accounting principles, prior to the enactment, the Trust’s temporary differences were not recorded as future income taxes. As at September 30, 2007, the total “temporary difference” (tax basis exceeds accounting basis) in the Trust is \$10.5 million. As at September 30, 2007, the Trust’s subsidiaries have tax basis of approximately \$480 million that is available to shelter future taxable income. Included in this tax basis are estimated non-capital loss carry forwards of approximately \$29.3 million that expire in years through 2026. In addition, the Trust has approximately \$21 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 32.94% (2006: 40.10%) to earnings before income taxes.

This difference results from the following items:

(\$000s)	Nine months ended September 30,	
	2007	2006
Expected income tax expense (recovery)	\$ (17,244)	\$ (10,539)
Distributions deducted for tax purposes	(12,516)	(21,873)
Impact of SIFT legislation	(1,165)	-
Crown royalties and charges	-	3,354
Resource allowance	-	(2,929)
Unit based compensation expense	1,073	1,755
Change in enacted tax rates	(137)	(19,825)
Other	32	1,014
Future income tax expense (recovery)	\$ (29,957)	\$ (49,043)

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 as special meeting costs within the statement of income for the nine month period ended September 30, 2007.

16. PER TRUST UNIT AMOUNTS

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
	2007	2006	2007	2006
Basic trust units outstanding	79,715,595	69,321,703	79,709,119	69,321,703
Dilutive effect of:				
Trust unit incentive rights outstanding	6,086,832	5,516,500	6,086,832	5,516,500
Units issuable for exchangeable shares	316,547	272,264	316,547	272,264
Units issuable for convertible debentures	5,390,625	5,390,625	5,390,625	5,390,625
Diluted trust units outstanding	91,509,599	80,501,092	91,509,599	80,501,092
Weighted average trust units outstanding	79,714,539	44,934,827	74,528,093	39,549,352
Dilutive effect of exchangeable shares, trust unit incentive plan and convertible debentures ⁽¹⁾	-	272,264	-	272,264
Diluted weighted average trust units outstanding	79,714,539	45,207,091	74,528,093	39,821,616

⁽¹⁾ A total of 316,547 (2006: nil) exchangeable shares, 6,086,832 (2006: 3,103,033) trust incentive units and 5,390,625 (2006: 5,390,625) trust units issuable pursuant to the conversion of convertible debentures were excluded from the calculation for the three month period ended September 30, 2007 as they were not dilutive. A total of 316,547 (2006: nil) exchangeable shares, 6,086,832 (2006: 721,377) trust incentive units and 5,390,625 (2006: 2,132,555) trust units issuable pursuant to the conversion of convertible debentures were excluded from the calculation for the nine month period ended September 30, 2007 as they were not dilutive.

17. RELATED PARTY TRANSACTIONS

During the nine month period ended September 30, 2007, the Trust paid \$1.0 million (2006: \$1.0 million) for legal services provided by a firm in which a current director and corporate secretary 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. COMMITMENTS

At the end of the third quarter of 2007, the Trust had committed to drill a total of 2 wells in Alberta with varying commitment dates up to end of the first quarter of 2008 pursuant to various farm-in agreements with oil and gas companies. True expects to satisfy these various drilling commitments at an estimated cost for True's interest of approximately \$2.8 million.

19. FINANCIAL INSTRUMENTS

At September 30, 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	\$ 3,295	\$ 3,295
Commodity contract liability	2,598	2,598
Long-term debt	159,212	159,212
Convertible debentures		
Debt component	79,021	
Equity component	5,119	
	84,140	81,075

The carrying values of accounts receivable, deposits and prepaid expenses, 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 September 30, 2007.

For the nine month period ended September 30, 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	\$ 7,670
Interest expense	13,542

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

Type	Period	Volume	Price Floor	Price Ceiling	Index
Oil collar	Oct. 1, 2007 to March 31, 2008	2,000 bbl/d	\$ 65.00 US	\$ 75.00 US	WTI
Oil collar	April 1, 2008 to Dec. 31, 2008	1,000 bbl/d	\$ 65.00 US	\$ 82.00 US	WTI
Oil collar	April 1, 2008 to Dec. 31, 2008	1,000 bbl/d	\$ 65.00 US	\$ 82.00 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 collar	Nov. 1, 2007 to March 31, 2008	5,000 GJ/day	\$ 8.00 CDN	\$ 9.05 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
Natural Gas fixed ⁽¹⁾	Jan. 1, 2008 to Dec. 31, 2008	5,000 GJ/day	\$ 6.65 CDN	\$ 6.65 CDN	AECO C
Natural Gas fixed ⁽¹⁾	Jan. 1, 2008 to Dec. 31, 2008	10,546 GJ/day	\$ 6.65 CDN	\$ 6.65 CDN	AECO C

⁽¹⁾ These contracts were entered into subsequent to September 30, 2007.

For the nine month period ended September 30, 2007, the gain (loss) on commodity contracts was comprised of the following:

(\$000s)	Activity in the period	Adjustments for new standards ⁽¹⁾	Total
Gain (loss) on commodity contracts			
Realized ⁽²⁾	\$ 10,352	\$ (3,262)	\$ 7,090
Unrealized ⁽³⁾	(7,858)	8,438	580
	\$ 2,494	\$ 5,176	\$ 7,670

⁽¹⁾ 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.

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

⁽³⁾ 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:

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