



For Immediate Release
TSX: TUI.UN

TRUE ENERGY TRUST ANNOUNCES 2006 YEAR END FINANCIAL RESULTS

March 1, 2007 – (TSX: TUI.UN) True Energy Trust (“True” or the “Trust”) is pleased to announce its financial and operating results for the year ended December 31, 2006. Highlights from the fourth quarter and year ended December 31, 2006 include:

- True generated record average sales volumes for the year of 13,861 boe per day, a 60% increase from 8,672 boe per day in 2005. Average sales volumes for the fourth quarter of 2006 were 19,747 boe per day, compared to 13,248 boe per day in the third quarter of 2006.
- Cash flow from operations* for 2006 was \$90.4 million on gross sales of \$220.9 million compared to cash flow from operations* of \$87.1 million on gross sales of \$161.7 million in 2005. For the fourth quarter of 2006, cash flow from operations* was \$31.8 million compared to \$32.9 million for the same period in 2005. The increase in cash flow for the 2006 year was the result of higher production volumes offset by lower natural gas prices. True’s realized natural gas prices in 2006 averaged \$6.75/mcf compared to \$9.41/mcf in 2005.
- Total capital expenditures for 2006, excluding corporate and property acquisitions and dispositions, were \$99.2 million compared to \$115.5 million in 2005. This decrease reflects the adjustment of capital expenditures while operating as a trust.
- Shellbridge Oil & Gas, Inc. and Prairie Schooner Petroleum Ltd. were acquired for an aggregate of \$413 million in 2006. Late in the third quarter of 2006, True completed the purchase of a steam assisted gravity drainage (“SAGD”) facility at Kerrobert, Saskatchewan. First phase implementation of the SAGD project on the Kerrobert field will occur during the first to third quarters of 2007 and is expected to provide a material production impact late in 2007 and significantly enhance ultimate recovery of reserves.
- True had a very active drilling and development program in 2006, drilling 98 (61.5 net) working interest wells with a 98% success rate. In the fourth quarter of 2006, True drilled 21 (10.1 net) working interest wells with a 95% success rate.
- True put in place a new \$225 million banking facility effective October 2, 2006. As at December 31, 2006, there was approximately \$67 million available under this facility.
- True has currently hedged approximately 33% of current natural gas production for the first quarter of 2007 and approximately 31% is hedged through to October 31, 2007.
- As at December 31, 2006, True had total tax pools of approximately \$498 million comprised of \$478 million tax pools in True’s subsidiaries that are available to shelter future taxable income and \$20 million of tax pools of the Trust as at December 31, 2006. True’s exploration and development activities will continue to add to these available tax pools in 2007.
- Net loss for 2006 was \$233.6 million compared to net earnings of \$13.9 million in 2005. This primarily reflects fourth quarter 2006 non-cash charges for the ceiling test write-down of property, plant and equipment of \$110.0 million and goodwill impairment of \$169.8 million.
- True maintains a large undeveloped land base of 1.1 million (0.7 million net) acres.
- The Trust replaced 4.6 times its production through capital development program and acquisition activities.

- At December 31, 2006, True's proved plus probable reserves stood at 48.7 mmboe, compared to 30.2 mmboe at December 31, 2005. The Trust's reserve life index on fourth quarter 2006 annualized production is 6.8 years.

On January 15, 2007, the Trust announced its intention to convert to a growth oriented, dividend paying intermediate exploration and production company (the "Reorganization"), pursuant to which holders of trust units of the Trust would receive an equal number of common shares from the newly formed corporation which will hold the assets previously held directly or indirectly by the Trust. The exchangeable shares will also be exchanged for common shares of the newly formed corporation based on the conversion ratio thereof. An Information Circular and Proxy Statement in connection with the Annual and Special Meeting will be mailed to securityholders on or about March 5, 2007, in advance of the March 30, 2007 meeting date. The Reorganization will be subject to all required regulatory approvals and securityholder approval by at least 66 2/3% of the votes cast by securityholders of the Trust and holders of the exchangeable shares.

* Refer to note (1) in the highlights section of the financial report in respect of the term "cash flow from operations".

True's 2006 financial report is presented below.

HIGHLIGHTS

	Years ended December 31	
	2006	2005
FINANCIAL		
<i>(CDN\$000s except unit and per unit amounts)</i>		
Revenue (before royalties and hedging)	220,913	161,670
Cash flow from operations ⁽¹⁾	90,391	87,137
Per basic trust unit	\$1.91	\$3.53
Per diluted trust unit ⁽²⁾	\$1.87	\$3.47
Net earnings (loss)	(233,564)	13,890
Per basic trust unit	\$(4.95)	\$0.56
Per diluted trust unit ⁽²⁾	\$(4.95)	\$0.55
Distributions paid	124,355	17,361
Per unit	\$2.64	\$0.48
Payout ratio before DRIP ^{(3) (4)}	98%	16%
Payout ratio after DRIP ^{(3) (4)}	64%	16%
Exploration and development	99,206	115,481
Corporate and property acquisitions	17,322	490
Capital expenditures - cash	116,528	115,971
Property dispositions - cash	(24,514)	-
Corporate acquisitions and other - non-cash	487,698	448,982
Total capital expenditures - net	579,712	564,953
Long-term debt	157,904	-
Convertible debentures	81,551	-
Bank debt	-	71,365
Working capital deficiency	36,361	39,764
Total net debt	275,816	111,129
Total assets	1,016,658	731,129
Unitholders' equity	505,096	392,269
OPERATING		
Daily sales volumes		
Crude oil and NGLs	(bbls/d)	5,317
Natural gas	(mcf/d)	51,264
Total oil equivalent	(boe/d)	13,861
Average prices		
Crude oil and NGLs	(\$/bbl)	48.00
Crude oil and NGLs (including hedging)	(\$/bbl)	47.54
Natural gas	(\$/mcf)	6.75
Natural gas (including hedging)	(\$/mcf)	6.93
Total oil equivalent	(\$/boe)	43.36
Total oil equivalent (including hedging)	(\$/boe)	43.88
Statistics		
Operating netback	(\$/boe)	22.60
Operating netback (including hedging)	(\$/boe)	23.12
Production expenses	(\$/boe)	9.23
General & administrative	(\$/boe)	2.94
Royalties as a % of sales after transportation		24%
		26%

	Years ended December 31	
	2006	2005
TRUST UNITS		
Trust units outstanding	70,275,703	36,176,196
Trust unit incentive rights outstanding	5,429,831	3,159,000
Units issuable for exchangeable shares	286,942	454,887
Units issuable for convertible debentures	5,390,625	-
Diluted trust units outstanding	81,383,101	39,790,083
Diluted weighted average trust units ⁽²⁾	47,217,258	25,133,085

TRUST UNIT TRADING STATISTICS

(CDN\$, except volumes) based on intra-day trading ⁽²⁾

High	21.30	25.88
Low	7.25	13.60
Close	7.49	20.80
Average daily volume	412,447	183,486

⁽¹⁾ The Management Discussion and Analysis ("MD&A") contains the term "cash flow from operations", which should not be considered an alternative to, or more meaningful than cash flow from operating activities as determined in accordance with Canadian generally accepted accounting principles ("GAAP") as an indicator of the Trust's performance. Therefore reference to diluted cash flow from operations or cash flow from operations per trust unit may not be comparable with the calculation of similar measures for other entities. Management uses cash flow from operations to analyze operating performance and leverage and considers cash flow from operations to be a key measure as it demonstrates the Trust's ability to generate the cash necessary to fund future capital investments and to repay debt. The reconciliation between cash flow from operations and cash flow from operating activities can be found in the MD&A. Cash flow from operations per trust unit is calculated using the diluted weighted average number of trust units for the period.

⁽²⁾ Restated for 2005 to reflect the consolidation of trust units effective November 2, 2005. In computing weighted average diluted earnings per trust unit for the year ended December 31, 2006 nil (2005: 454,887) trust units were added to the 47,217,258 (2005: 24,678,198 after consolidation) weighted average number of trust units outstanding during the year for the dilutive effect of exchangeable shares. A total of 286,942 exchangeable shares (2005: nil), 5,429,831 (2005: 3,159,000) trust incentive units and 2,953,767 (2005: nil) trust units issuable pursuant to conversion of convertible debentures were excluded from the calculation of diluted earnings per trust unit for the year ended December 31, 2006 as they were not dilutive. To calculate weighted average diluted cash flow from operations for the year ended December 31, 2006, a total of \$4.0 million for interest accretion expense was added to the numerator and 286,942 (2005: nil) exchangeable shares and 2,953,767 trust units were added to the denominator for units issuable on conversion of convertible debentures, resulting in diluted weighted average trust units of 50,457,967 under this calculation.

⁽³⁾ "Payout ratio" refers to distributions measured as a percentage of cash flow from operating activities including the change in non-cash working capital balances. Previously, until the second quarter ended June 30, 2006, the Trust had calculated the payout ratio as distributions divided by cash flow from operations, which excludes the change in non-cash working capital balances. This change in calculation of the payout ratio is consistent with recent staff notices provided by the Canadian Securities Administrators in respect of income trusts.

⁽⁴⁾ DRIP refers to distributions reinvested pursuant to the Premium Distribution™ Reinvestment, Distribution Reinvestment and Optional Trust Unit Purchase Plan.

REPORT TO UNITHOLDERS

The 2006 year was the first full year of True operating as an oil and gas energy trust, focused on providing unitholder distributions. The year presented endless challenges from dramatically decreasing commodity prices to sweeping government proposed tax changes in the trust sector. Although a disappointing year in the capital markets for the Trust, a number of operational accomplishments were achieved. The annual operational results reflect the Trust's response to the challenges of weaker crude oil and natural gas prices.

Accomplishments for the fourth quarter and year ended December 31, 2006 include:

Distributions

The Board maintained ten consecutive monthly distributions of \$0.24 per unit through to October 16, 2006. The monthly distributions paid on November 15, 2006 and December 15, 2006 were set at \$0.18 per unit. Additionally, monthly distributions declared and paid on January 15, 2007 and February 15, 2007 were \$0.12 per unit, with a further announced distribution of \$0.12 per unit to be paid on March 15, 2007.

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

Production

2006 production averaged 13,861 boe/d as compared to 8,672 boe/d in 2005, representing a 60% increase. Average sales volumes for the fourth quarter of 2006 were 19,747 boe/d, compared to 13,248 boe/d in the third quarter of 2006, which reflects the closing of the acquisition of Prairie Schooner Petroleum Ltd. ("Prairie Schooner") late in the third quarter.

During the first six months of 2007, we will continue to be very active on the drilling front, focused on the implementation of the Kerrobert SAGD program and drilling in west central Alberta. Capital expenditures in the first quarter of 2007 are expected to be approximately \$50 million.

Production for the first quarter of 2007, based on field estimates, is expected to be approximately 19,000 boe/d. The decrease in production expected for this period reflects shut-in production at Kerrobert as facility upgrades and new steam wells are being drilled, which is expected to materially increase production later in the year. We currently expect production to average approximately 20,500 boe/d for 2007.

Financial

Cash flow from operations for 2006 was \$90.4 million on gross sales of \$220.9 million compared to cash flow from operations of \$87.1 million on gross sales of \$161.7 million in 2005. For the fourth quarter of 2006, cash flow from operations was \$31.8 million compared to \$32.9 million for the same period in 2005. The increase in cash flow for the 2006 year was the result of higher production volumes offset by lower natural gas prices. True's realized natural gas prices in 2006 averaged \$6.75/mcf compared to \$9.41/mcf in 2005.

The net loss for 2006 was \$233.6 million compared to net earnings of \$13.9 million in 2005. This primarily reflects fourth quarter 2006 non-cash charges for the ceiling test write-down of property, plant and equipment of \$110.0 million and goodwill impairment of \$169.8 million.

Drilling

During the 2006 year, True achieved a 98% success rate in the drilling or participation in 98 (61.5 net) working interest wells, resulting in 72 (41.6 net) gas wells, 24 (18.4 net) oil wells and 2 (1.5 net) dry holes. In the fourth quarter of 2006, True drilled 21 (10.1 net) working interest wells with a 95% success rate, resulting in 15 (6.7 net) gas wells, 4 (1.4 net) oil wells, 1 (1 net) stratigraphic test oil well and 1 (1 net) dry

hole. True successfully participated in 17 (7.6 net) wells in Alberta and 3 (1.5 net) wells in Saskatchewan during the fourth quarter.

Acquisitions

On June 23, 2006, True completed the acquisition of Shellbridge Oil & Gas, Inc. ("Shellbridge") at a cost of \$68.8 million. On September 22, 2006, True completed the acquisition of Prairie Schooner at a cost of \$344.4 million.

Late in September 2006, the Trust completed the purchase of a facility in the Kerrobert, Saskatchewan area which will allow the Trust to begin implementation of the SAGD phase of the project. During the first phase of implementation over the first to third quarters of 2007, the Trust plans to convert a number of existing wells to steam injectors and drill additional wells that will be used as producing well bores. The facility is currently running at 600 bbls/d of heavy oil production with capacity of approximately 5,000 bbls/d. Also included in the acquisition were lands on which True has identified a number of development and exploration opportunities.

Liquidity

At December 31, 2006, True had \$153.0 million drawn on a revolving term credit facility, \$4.9 million drawn on a demand operating facility, \$81.6 million in convertible debentures (liability component) and the balance a net working capital deficiency which resulted in total net debt of \$275.8 million.

On October 2, 2006, the existing \$150 million credit facility was replaced by a \$225 million facility provided by a Canadian chartered bank, a U.S. bank, a foreign bank and one institutional lender. As at December 31, 2006, there is approximately \$67 million available under this lending facility.

Following the implementation of the Premium DistributionTM Reinvestment, Distribution Reinvestment and Optional Trust Unit Purchase Plan ("DRIP") effective March 27, 2006, participation in the first eight months of the plan averaged approximately 48%. 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 the DRIP until further notice. At the current lower unit price, this move was considered prudent to avoid further dilution to unitholders through the DRIP program.

True has actively increased its commodity price hedging program since July 2006. At present, True has hedged approximately 33% of current natural gas production through to the end of March 2007, and approximately 31% of current natural gas production is hedged in the second quarter through to October 31, 2007. The AECO natural gas collars have a weighted average floor of CDN\$8.63 per GJ for the first quarter of 2007 and CDN\$7.00 per GJ for the second quarter through October 2007. In addition, True has AECO natural gas put options (price floor) at CDN\$8.00 in the first quarter, in addition to fixed price natural gas contracts with an average of CDN\$9.42 per GJ for the first quarter and approximately CDN\$7.03 to CDN\$7.05 per GJ for the second quarter through to October 2007. As well, True has entered into WTI crude oil puts with a floor of US\$70.00 per barrel for 1,800 bbls per day for the first quarter of 2007 and an average price floor of US\$64.55 per barrel for 2,200 bbls per day during the second quarter of 2007. True will continue to implement various hedging strategies during 2007 with a focus on maintaining sufficient cash flow to provide funding of True's 2007 capital program.

Announcement of Plan to Convert to a Corporation

On October 31, 2006 the Federal government announced sweeping changes to the Canadian tax system which will, in essence, impose a tax on distributions from the Trust commencing with the 2011 tax year. The impact of the federal government's announcement resulted in a substantial decline in the market value of all trust units generally, including True. In the absence of final legislation implementing the 2006 proposed changes, the implications are difficult to fully evaluate and no assurance can be provided as to the extent and timing of their application to the Trust and our unitholders. Clearly, this has created a lot of uncertainty in the oil and gas trust sector.

The Board evaluated a number of alternatives and is recommending the Reorganization outlined in the Trust's January 15, 2007 press release.

Pursuant to the Reorganization announced on January 15, 2007, holders of trust units of the Trust would receive an equal number of common shares from the newly formed corporation which will hold the assets previously held directly or indirectly by the Trust. The exchangeable shares will also be exchanged for common shares of the newly formed corporation based on the conversion ratio thereof. An Information Circular and Proxy Statement in connection with the Meeting will be mailed to securityholders on or about March 5, 2007 in advance of the March 30, 2007 meeting date. The Reorganization will be 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. We encourage all our securityholders to carefully review the forthcoming information circular and vote in person or by proxy at the March 30th Meeting.

Paul R. Baay
President & CEO
March 1, 2007

MANAGEMENT'S DISCUSSION AND ANALYSIS

March 1, 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 audited consolidated financial statements for the years ended December 31, 2006 and 2005 for the Trust. This commentary is based on information available to, and is dated, March 1, 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 "payout ratio" which is not a recognized measure under Canadian GAAP. Management uses payout ratio to refer to distributions measured as a percentage of cash flow available for development and acquisition opportunities as well as overall sustainability of distributions. True calculates this measure consistent with recent staff notices provided by the Canadian Securities Administrators in respect of income trusts. True's method of calculating this measure may differ from other entities, and accordingly, may not be comparable to the measure 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 True'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, effects of drilling or wells to be tied-in, the effect of government announcements, proposals and legislation, plans regarding hedging, timing of anticipated adoption of new accounting rules, estimated cash flow from operations for the first quarter of 2007, wells to be drilled, the effect of recent legislation, expected or anticipated production rates, the weighting of production between different commodities, commodity prices, exchange rates, expected levels of royalty rates, operating costs, general and administrative costs, costs of services and other costs and expenses, capital expenditures and the nature of capital expenditures and the method of financing thereof, may constitute forward-looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing

and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources. The recovery and reserve estimates of True's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Events or circumstances may cause actual results to differ materially from those predicted, as a result of the risk factors set out and other known and unknown risks, uncertainties, and other factors, many of which are beyond the control of True. The reader is cautioned not to place undue reliance on this forward looking information. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhausted. Additional information on these and other factors that could effect True's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), 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.

Corporate Developments

Acquisition of Prairie Schooner Petroleum Ltd.

On September 22, 2006, the Trust completed the acquisition of Prairie Schooner Petroleum Ltd. ("Prairie Schooner") on the basis of 1.22 trust units of True for each outstanding share of Prairie Schooner, pursuant to a plan of arrangement under the Business Corporations Act (Alberta). In total, True issued 25,759,563 trust units to acquire Prairie Schooner.

Acquisition of Shellbridge Oil & Gas, Inc.

On June 23, 2006 the Trust completed the acquisition of Shellbridge Oil & Gas, Inc. ("Shellbridge") on the basis of 0.14 trust units of True for each outstanding share of Shellbridge, pursuant to a plan of arrangement under the Business Corporations Act (Alberta). In total, True issued 4,389,366 trust units to acquire Shellbridge.

Further information on the acquisitions of Prairie Schooner and Shellbridge is found in notes 3 and 5 of the consolidated financial statements.

Plan of Arrangement – Conversion to a Trust

On November 2, 2005 True Energy Inc. and TKE Energy Trust ("TKE") entered into a business combination whereby True Energy Inc. acquired TKE via a reverse takeover, thus creating True Energy Trust ("True" or the "Trust"), and a publicly listed exploration focused company, Vero Energy Inc. ("Vero"), pursuant to a Plan of Arrangement ("TKE Arrangement").

Concurrent with approval of the TKE Arrangement, TKE received approval from Unitholders at the TKE Unitholder Meeting to consolidate its existing outstanding trust units on a one-for-two (1:2) basis and to change its name to "True Energy Trust". Under the TKE Arrangement, True Energy Inc. and TKE Energy Inc. were amalgamated to form the new administrator of the Trust under the name True Energy Inc.

The TKE Arrangement resulted in True Energy Inc. shareholders receiving, for each True common share held: (i) 0.5 of a pre-consolidated trust units (0.25 of a post-consolidated Trust Unit); (ii) 0.10 of a Vero Share; and (iii) one Vero arrangement warrant. Each whole Vero arrangement warrant entitled the holder to acquire 0.0655 of a Vero Share, for a period of 30 days following November 2, 2005.

Pursuant to the TKE Arrangement, the Trust owns 100% of the assets of TKE and approximately 90% of the former True Energy Inc. assets. The remainder of the True Energy Inc. assets were transferred to Vero, consisting primarily of producing assets and undeveloped lands in the Whitecourt/ Edson area of west central Alberta.

The acquisition of True Energy Inc. by TKE Energy Trust to form the Trust has been accounted for as a reverse takeover of TKE and a continuity of interests of True Energy Inc. Accordingly, the consolidated financial statements for 2005 reflect the financial position, results of operations and cash flows as if the Trust had always carried on the business formerly carried on by True Energy Inc. The year ended December 31, 2005 reflects the results of operations and cash flows of True Energy Inc. and its subsidiaries for the period January 1 to November 1, 2005, and the results of operations and cash flows of the Trust (including TKE and its subsidiaries) for the period November 2 to December 31, 2005. The comparative figures are the results of True Energy Inc. and its subsidiaries. Due to the conversion into a trust, certain information included in Management's Discussion and Analysis for prior periods may not be directly comparable.

The term "units" has been used to identify both the trust units and the exchangeable shares of the Trust issued on or after November 2, 2005 as well as the common shares of True Energy Inc. outstanding prior to the conversion on November 2, 2005.

Fourth Quarter 2006

Cash flow from operations during the fourth quarter of 2006 was \$31.8 million, a decrease of 3% compared to \$32.9 million for the fourth quarter of 2005. By comparison, in the last quarter of 2006, True's earnings were a net loss of \$250.7 million compared to net earnings of \$3.2 million in the fourth quarter of 2005. The net loss during the fourth quarter is primarily due to non-cash charges of a ceiling test write down of \$110 million and a goodwill impairment charge of \$169.8 million.

Sales volumes for the three months ended December 31, 2006 averaged 19,747 boe/d, up 83% from the 10,784 boe/d produced in the fourth quarter of 2005. Production during the last quarter of 2006 included the additional volumes derived from the Shellbridge and Prairie Schooner acquisitions as well as drilling activity during 2006. In the fourth quarter of 2006, average sales volumes increased 49% from the third quarter 2006 average volumes of 13,248 boe/d as a result of the first full quarter of Prairie Schooner natural gas volumes. Natural gas sales averaged 73.8 Mmcf/d during the last quarter of 2006, compared to 42.5 Mmcf/d in the fourth quarter of 2005. The weighting toward natural gas averaged 62% in the fourth quarter, compared to 66% in the corresponding period of 2005. In the last quarter of 2006, True's natural gas exploration efforts focused on drilling 15 (6.7 net) wells, primarily in the Huxley, Ferrier and Willesden Green areas. Crude oil, condensate and NGL sales volumes averaged 7,440 bbls/d in the fourth quarter compared to 3,699 bbls/d during the same period of 2005. During the fourth quarter of 2006, True drilled 1 (0.4 net) heavy oil well at Mantario, 2 (0.8 net) light oil wells at George and 1 (0.3 net) light oil well at Gage. During the fourth quarter of 2006, True invested \$25.9 million on capital projects, excluding corporate and asset acquisitions and dispositions, compared to \$52.6 million in 2005.

During the fourth quarter of 2006, True experienced an overall decrease in commodity prices. The average Alberta Spot price for natural gas during this quarter was 43% lower than in the same period in 2005. For the three months ending December 31, 2006, before transportation and hedging, True received an average natural gas price of \$6.98/Mcf, 41% less than \$11.88/Mcf in the same period in 2005 and 16% higher than \$6.02/Mcf in the third quarter of 2006. For heavy crude oil, True received an average price before transportation of \$34.82/bbl during the fourth quarter of 2006, 14% more than \$30.53/bbl in the same period in 2005 and 33% less than \$51.92/bbl in the third quarter of 2006. In comparison, the average reference price for Bow River crude in the fourth quarter of 2006 was 7% more than the average 2005 price in the same period. For light oil, condensate and NGL's, True received an average price of \$60.34/bbl before hedging during the last quarter of 2006, 3% less than the average price of \$62.13/bbl received in the same period of 2005, compared to a 9% decrease in the Edmonton par reference price. The average price for light oil, condensate and NGLs for True was 13% lower than the \$69.68/bbl for the third quarter of 2006. During the fourth quarter of 2006, pre-transportation revenue of \$76.8 million was 26% more than the corresponding 2005 period.

In the fourth quarter of 2006, the Trust paid \$18.5 million in royalties, compared to \$15.5 million in the same period in 2005. As a percentage of pre-hedge sales (after transportation costs), royalties were 25% in the fourth quarter of 2006 compared to 26% in the same period in 2005. In this same period of 2006, operating costs totaled \$17.7 million, compared to \$7.6 million recorded in the same period of 2005. During the fourth quarter of 2006, operating costs averaged \$9.76/boe, up from the \$7.66/boe incurred during the fourth quarter of 2005, primarily reflecting the different property mix and increased field costs for services. In comparison, operating costs for the third quarter of 2006 averaged \$8.58/boe. True is forecasting operating costs of approximately \$9/boe in 2007. During the fourth quarter of 2006, company field operating netbacks decreased by 43% to \$21.05/boe compared to 2005, driven primarily by decreased natural gas prices, increased operating costs, and partially offset by decreased royalties. In comparison, the company field operating netback for the third quarter of 2006 was \$23.66/boe. Field operating netbacks for natural gas before hedging during the fourth quarter of 2006 of \$3.78/Mcf were 49% less than the 2005 netbacks, reflecting a significantly lower gas price offset by a reduction in

royalties. In comparison, the field operating netback for natural gas for the third quarter of 2006 was \$3.12/Mcf. Field operating netbacks before hedging for crude oil and NGLs during the fourth quarter of 2006 averaged \$18.35/bbl, down from \$22.96/bbl during the fourth quarter of 2005, primarily as a result of a small increase in the overall commodity price received, offset by higher operating costs associated with increased heavy oil production. In comparison, the field operating netback for crude oil and NGLs for the third quarter of 2006 was \$30.32/bbl.

In the fourth quarter of 2006, the net cost of general and administrative expenses was \$5.9 million, compared to \$1.2 million in the comparable 2005 period reflecting the increased costs for services and staffing as a result of the Shellbridge and Prairie Schooner acquisitions, as well as increased staffing to support higher production levels.

Depletion, depreciation and accretion expense for the fourth quarter of 2006 was \$53.1 million, compared to \$28.7 million in 2005, reflecting the acquisition of Shellbridge and Prairie Schooner assets in 2006 and increased production in the quarter.

Net Earnings (Loss) and Cash Flow from Operations

True generated cash flow from operations of \$90.4 million (\$1.87 per diluted unit) for the year ended December 31, 2006, up 4% from the \$87.1 million (\$3.47 per diluted unit) for the year of 2005. Lower commodity prices, despite increased volumes were the primary factors contributing to the decrease in cash flow per diluted unit.

True generated a net loss of \$233.6 million (\$(4.95) per diluted unit) in the year 2006 compared to net earnings of \$13.9 million (\$0.55 per diluted unit) in 2005. Net loss per unit in 2006 was impacted by higher depletion, depreciation and accretion charges from the 2006 acquisitions of Shellbridge and Prairie Schooner, a ceiling test write-down of \$110.0 million, a goodwill impairment charge of \$169.8 million and higher unit-based compensation expenses due to increased personnel numbers.

Cash Flow From Operations and Net Earnings

<i>(\$000s, except per unit amounts)</i>	Years ended December 31,	
	2006	2005
Cash flow from operations	90,391	87,137
Basic (\$/unit)	1.91	3.53
Diluted (\$/unit)	1.87	3.47
Net earnings (loss)	(233,564)	13,890
Basic (\$/unit)	(4.95)	0.56
Diluted (\$/unit)	(4.95)	0.55

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, ARTC 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

<i>(\$000s, except per unit amounts)</i>	Years ended December 31,	
	2006	2005
Cash flow from operations	90,391	87,137
Change in non-cash working capital	36,925	21,665
Cash flow from operating activities	127,316	108,802
Funding from convertible debentures and DRIP	124,564	-
Cash withheld to fund capital and other expenditures	(127,525)	(91,441)
Distributions paid	124,355	17,361
Accumulated distributions, beginning of year	17,361	-
Accumulated distributions, end of year	141,716	17,361
Distributions per unit for outstanding units in the year (2005: two month period)	2.64	0.48
Accumulated distributions per unit, beginning of year	0.48	-
Accumulated distributions per unit, end of year	3.12	0.48

Following the implementation of the Premium DistributionTM Reinvestment, Distribution Reinvestment and Optional Trust Unit Purchase Plan ("DRIP") effective March 27, 2006, participation in the first eight months of the plan averaged approximately 48%. Funds reinvested in the Trust through this plan will be available to fund capital and other expenditures. On November 16, 2006, the Trust announced the suspension of equity available for reinvestment under DRIP until further notice.

Payout Ratio

<i>(\$000s, except percentages)</i>	Years ended December 31,	
	2006	2005
Cash flow from operations	90,391	87,137
Change in non-cash working capital	36,925	21,665
Cash flow from operating activities	127,316	108,802
Distributions paid before DRIP	124,355	17,361
DRIP	(42,608)	(301)
Distributions after DRIP	81,747	17,060
Payout ratio before DRIP	98%	16%
Payout ratio after DRIP	64%	16%

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

Sales Volumes

Sales volumes for the year ended December 31, 2006 averaged 13,861 boe/d, an increase of 60% compared to 8,672 boe/d reported in the year 2005. This increase was due to a combination of results from drilling activity and the acquisitions of TKE effective November 2, 2005, Shellbridge effective June 23, 2006 and Prairie Schooner effective September 22, 2006. Estimated production for the first quarter of 2007, based on field estimates, is approximately 19,000 boe/d. True currently has 12 (6.5) Alberta wells and 1 (0.8 net) Saskatchewan wells remaining to be tied-in; current drilling operations are expected to add to this backlog in the short term, but contributing to production later in the year.

For the year ended December 31, 2006, the weighting towards natural gas production averaged 62% compared to 66% in 2005. Heavy oil sales made up 26% of total production for the 2006 year compared to 24% in 2005. The increase in heavy oil weighting for the year was due to the addition of primarily heavy oil weighted assets from Shellbridge at the end of the second quarter of 2006. The September 2006 acquisition of Prairie Schooner added significant natural gas volumes which has since increased the natural gas production weighting. Currently, the Trust estimates that the weighting towards natural gas production is approximately 64%.

Sales Volumes

		Years ended December 31,	
		2006	2005
Natural gas	(mcf/d)	51,264	34,287
Heavy oil	(bbls/d)	3,612	2,075
Light oil and condensate	(bbls/d)	1,285	591
NGLs	(bbls/d)	420	292
Total crude oil and NGLs	(bbls/d)	5,317	2,958
Total boe/d	(6:1)	13,861	8,672

Sales of natural gas averaged 51.3 mmcf/d for 2006, compared to 34.3 mmcf/d in 2005, an increase of 50%.

Crude oil and NGLs sales for 2006 averaged 5,317 bbls/d up 80% from 2005 average sales of 2,958 bbls/d. Most of this increase was due to greater heavy oil volumes from the acquisition of Shellbridge in June 2006 and an increased drilling program. During 2006, True also drilled and placed on production 18 (15.4 net) heavy oil wells with the majority of these wells in the Hoosier, Mantario and Kerrobert, Saskatchewan areas.

Commodity Prices

The impact of changes in the Canadian dollar from the conversion of US\$ based commodities prices reduced profitability during the year ended December 31, 2006 when compared to the same period in 2005. The U.S./Canadian exchange rate changed 7% from an average of 0.8261 in 2005 to 0.8817 in 2006.

Average Commodity Prices

	Years ended December 31,		% change
	2006	2005	
Exchange rate (US\$/Cdn\$)	0.8817	0.8261	7
Natural gas:			
NYMEX (US\$/mmbtu)	6.99	9.01	(22)
Alberta spot (\$/mcf)	6.17	8.65	(29)
True's average price (\$/mcf)	6.75	9.41	(28)
True's average price (including hedging) (\$/mcf)	6.93	9.41	(26)
Crude oil:			
WTI (US\$/bbl)	66.23	56.59	17
Edmonton par – light oil (\$/bbl)	73.30	69.18	6
Bow River – medium/heavy oil (\$/bbl)	51.54	43.83	18
Hardisty Heavy – heavy oil (\$/bbl)	43.32	34.35	26
True's average prices (\$/bbl)			
Light crude and condensate	66.15	64.19	3
Light crude and condensate (including hedging)	64.26	63.19	2
NGLs	51.15	52.69	(3)
Light crude oil, condensate and NGLs	62.46	60.39	3
Light crude oil, condensate and NGLs (including hedging)	61.03	59.72	2
Heavy crude oil	41.17	32.23	28
Total crude oil and NGLs	48.00	40.64	18
Total crude oil and NGLs (including hedging)	47.54	40.44	18

True's natural gas is primarily sold on the daily spot market. During 2006, the Alberta Spot reference price decreased by 29% compared to 2005. Similarly, True's average sales price before transportation and hedging for 2006 averaged \$6.75/mcf for its natural gas, 28% less than the \$9.41/mcf received in the prior year.

For heavy crude oil, True received an average price before transportation of \$41.17/bbl during 2006, an increase of 28% over 2005 prices. The Bow River and Hardisty Heavy reference prices increased by 18% and 26%, respectively. The majority of True's heavy crude oil density ranges between 11 and 16 degrees API consistent with the Hardisty Heavy reference price. The Trust blends most of its heavy oil with condensate on a 4:1 ratio to meet pipeline requirements. The lower comparative prices for condensate purchased for blending purposes has resulted in a relatively stronger price gain for the Trust's product than the reference price.

For light oil, condensate and NGLs, True recorded an average \$62.46/bbl before hedging during 2006, 3% greater than the average price received in 2005. During this period, the Edmonton par price increased by 6%. The Edmonton par price peaked in excess of \$80/bbl during July 2006 and since decreased for the remainder of 2006.

Revenue

Revenue before other income and transportation for the year ended December 31, 2006 was \$219.4 million, 36% greater than the \$161.6 million in 2005. The higher revenue was the result of significant growth in production volumes for natural gas, crude oil, condensate and NGLs, despite lower overall crude oil and natural gas prices.

(\$000s)	Years ended December 31,	
	2006	2005
Light crude oil and condensate	31,030	13,852
NGLs	7,846	5,617
Heavy oil	54,278	24,402
Crude oil and NGLs	93,154	43,871
Natural gas	126,216	117,758
Total revenue before other	219,370	161,629
Other	1,543	41
Total revenue before royalties and hedging	220,913	161,670
Gain (loss) on commodity contracts	2,639	(217)
Total	223,552	161,453

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.

Pursuant to the agreement between the Trust and Prairie Schooner entered into in connection with the acquisition of Prairie Schooner, both Prairie Schooner and True agreed to hedge up to 30% of the current production during the winter on a mutually agreed basis. Since July 2006, True has actively increased its hedging program, entering into various crude oil and natural gas hedging contracts. True also assumed certain hedging contracts from the Prairie Schooner acquisition. Currently, the Trust has hedged volumes of 1,800 bbl/d of crude oil and liquids and 26,000 GJ/d of natural gas for the first quarter 2007, 2,200 bbls/d of crude oil and liquids and 25,000 GJ/d of natural gas for the second quarter 2007, 25,000 GJ/d of natural gas for the third quarter 2007 and 11,739 GJ/d of natural gas for the fourth quarter 2007. The Trust plans to implement various hedging strategies during 2007 with a focus on maintaining sufficient cash flow to provide funding of True's 2007 capital program.

A summary of the hedge volumes and average prices by quarter is shown in the following tables (see Note 18 to the consolidated financial statements for a detailed disclosure of all commodity contracts in place as at March 1, 2007):

Crude oil and liquids		Average Volumes (bbls/d)			
	Q1 2007	Q2 2007	Q3 2007	Q4 2007	
Put option (price floor)	1,800	2,200	-	-	

Average Price (US\$/bbl WTI)		Q1 2007	Q2 2007	Q3 2007	Q4 2007
Put option price floor		70.00	64.55	-	-

Natural gas		Average Volumes (GJ/d)			
	Q1 2007	Q2 2007	Q3 2007	Q4 2007	
Costless collars	8,000	15,000	15,000	5,031	
Put option (price floor)	13,000	-	-	-	
Fixed	5,000	10,000	10,000	6,708	
Total GJ/d	26,000	25,000	25,000	11,739	

Average Price (\$/GJ AECO C)		Q1 2007	Q2 2007	Q3 2007	Q4 2007
Collar ceiling price		10.71	9.29	9.29	9.29
Collar floor price		8.63	7.00	7.00	7.00
Put option price floor		8.00	-	-	-
Fixed		9.42	7.05	7.05	7.03

The following is a summary of the gain (loss) on commodity contracts for the year ended December 31, 2006:

Commodity contracts				
	Crude Oil & Liquids	Natural Gas	2006 Total	2005 Total
(\$000s)				
Realized cash gain (loss) on contracts ⁽¹⁾	(890)	3,529	2,639	(217)
Unrealized gain (loss) on contracts	-	-	-	-
Total gain (loss) on commodity contracts	(890)	3,529	2,639	(217)

⁽¹⁾ Includes the amortization of natural gas put option premiums of \$1.8 million for the year ended December 31, 2006.

All of the existing contracts as of December 31, 2006 require monthly settlement and have been designated as hedges in accordance with Accounting Guideline 13. Further, the estimated fair value of open hedging contracts at the end of each reporting period is disclosed in accordance with this standard. As at December 31, 2006, the unrealized gain on the then outstanding commodity contracts, which changes on a daily basis, was \$8.2 million.

Effective January 1, 2007, True will be required to adopt Section 1530 "Comprehensive Income", Section 3855 "Financial Instruments – Recognition and Measurement" and Section 3865 "Hedges" issued by the CICA. Further details are discussed in the Financial Reporting Update section of this report.

Royalties

For the 2006 year, total royalties were \$51.8 million, compared to \$40.8 million incurred in 2005 up 27%, which was slightly less than the 36% increase in total revenue for the year. Overall royalties as a percentage of revenue (after transportation costs) in 2006 was 24%, compared with 26% in 2005. True recorded its maximum Alberta Royalty Tax Credit ("ARTC") in 2006. Royalties as a percentage of revenue (after transportation costs) in the year ended December 31, 2006 varied in the 16% to 28% range, reflecting gas cost allowance credits received and the relative commodity price changes combined with the lower overall royalty rate on the TKE asset base. The ARTC program has been eliminated effective January 1, 2007 which will effectively increase royalties by \$0.5 million per year.

Royalties by Commodity Type <i>(\$000s, except where noted)</i>	Years ended December 31,	
	2006	2005
Light crude oil and condensate	4,728	2,544
\$/bbl	10.08	11.79
Average light crude oil and condensate royalty rate (%)	16	15
NGLs	1,979	1,138
\$/bbl	12.90	10.67
Average NGLs royalty rate (%)	25	19
Heavy Oil	14,395	5,107
\$/bbl	10.91	6.75
Average heavy oil royalty rate (%)	28	22
Natural Gas	30,714	32,029
\$/mcf	1.64	2.56
Average natural gas royalty rate (%)	25	28
Total	51,816	40,818
\$/boe	10.24	12.90
Average total royalty rate (%)	24	26

Royalties, by Type

<i>(\$000s)</i>	Years ended December 31,	
	2006	2005
Crown royalties, net of ARTC	32,243	28,739
Indian Oil and Gas Canada royalties	2,948	909
Freehold & GORR	16,625	11,170
Total	51,816	40,818

Expenses

<i>(\$000s)</i>	Years ended December 31,	
	2006	2005
Production	46,685	21,219
Transportation	6,517	3,525
General and administrative	14,896	4,231
Interest and financing charges	10,665	1,308
Unit-based compensation	6,597	5,402

Expenses per boe

(\$ per boe)	Years ended December 31,	
	2006	2005
Production	9.23	6.70
Transportation	1.29	1.11
General and administrative	2.94	1.34
Interest and financing charges	2.11	0.41
Unit-based compensation	1.30	0.43

Production Expenses

For the 2006 year, production expenses totaled \$46.7 million, compared to \$21.2 million recorded in 2005. During 2006, production expenses averaged \$9.23/boe, an increase of 38% over 2005. This increase in production expenses is largely due to a different property mix along with inflationary pressure on the costs of services.

Production Expenses, by Commodity Type

(\$000s, except where noted)	Years ended December 31,	
	2006	2005
Light crude oil and condensate	6,305	2,115
\$/bbl	13.44	9.80
NGLs	1,568	500
\$/bbl	10.22	4.69
Heavy oil	13,754	5,420
\$/bbl	10.43	7.16
Natural gas	25,058	13,184
\$/mcf	1.34	1.05
Total	46,685	21,219
\$/boe	9.23	6.70

Transportation

Transportation costs continue to be approximately 2% to 3% of gross revenues for the year ended December 31, 2006 and 2005.

Operating Netbacks

For the 2006 year, corporate field operating netbacks (before hedging) decreased by 26% to \$22.60/boe from \$30.34/boe in 2005, primarily resulting from the weaker natural gas prices, increased production expenses and offset somewhat by increased prices for crude oil and NGLs. After including hedging activities, corporate field operating netbacks for 2006 was \$23.12/boe compared to \$30.28/boe in 2005.

Field Operating Netbacks – Corporate (before hedging)

(\$/boe)	Years ended December 31,	
	2006	2005
Sales	43.36	51.06
Transportation	(1.29)	(1.12)
Royalties	(10.24)	(12.90)
Production expense	(9.23)	(6.70)
Field operating netback	22.60	30.34

Field operating netbacks for natural gas during 2006 decreased 36% to \$3.59/mcf, compared to \$5.62/mcf for 2004, reflecting the weaker natural gas prices experienced. Per unit royalties decreased by 36% reflecting the change in asset base through acquisitions. After including hedging activities, field operating netbacks for natural gas for 2006 was \$3.77/mcf compared to \$5.62/mcf in 2005.

Field Operating Netbacks - Natural Gas (before hedging)

(\$/mcf)	Years ended December 31,	
	2006	2005
Sales	6.75	9.41
Transportation	(0.18)	(0.18)
Royalties	(1.64)	(2.56)
Production expense	(1.34)	(1.05)
Field operating netback	3.59	5.62

Field operating netbacks for crude oil and NGLs averaged \$24.36/bbl during 2006, up 3% compared to \$23.81/bbl for 2005, compared to an 18% increase in crude oil and NGLs sales price. This reflects the increased weighting of True's production of heavy oil compared to light oil and NGLs and the corresponding increase in average sales prices for heavy oil relative to light oil and NGLs, offset somewhat by increased production costs associated with heavy oil. After including hedging activities, field operating netbacks for crude oil and NGLs was \$23.90/boe compared to \$23.61/boe in 2005.

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

(\$/bbl)	Years ended December 31,	
	2006	2005
Sales	48.00	40.64
Transportation	(1.63)	(1.25)
Royalties	(10.87)	(8.14)
Production expense	(11.14)	(7.44)
Field operating netback	24.36	23.81

General and Administrative

Net general and administrative expenses for the year ended December 31, 2006 were \$14.9 million compared to \$4.2 million for the same period in 2005. On a per-unit of production basis, general and administrative expenses ("G&A") in 2006 are \$2.94/boe, compared to \$1.34/boe in 2005.

The increase during the first nine months of 2006 is attributed to higher costs incurred for reserve reporting, audit costs, annual reporting charges for preparation and mailing, recruiting, annual registration, securities filing fees, internal control compliance and employee cash compensation. The most significant increase in G&A expenses was due to increased staff levels in relation to the three acquisitions since November 2005 and higher compensation costs. As a result of unprecedented levels of activity for the Trust and for the industry as a whole, the costs associated with hiring, compensating and retaining employees and consultants have risen significantly. Total employee compensation and benefit costs for 2006 increased by 91% over 2005 which reflects the increased personnel and average increases in compensation over the prior year that were necessary to maintain competitive for retaining employees in the marketplace.

G&A expenses in 2006 include \$523,000 or \$0.10/boe for external costs associated with internal control compliance under Multilateral Instrument 52-109 compared to nil in 2005.

Other specific increases in G&A expenses from 2005 to 2006 include approximately \$652,000 related to prior year underaccruals of 2005 G&A, as well as \$542,000 (2005 – nil) for bad debts recorded in the fourth quarter of 2006.

The Trust estimates G&A costs/boe to decrease to approximately \$2.28/boe in 2007.

General and Administrative Expenses

(\$000s, except where noted)	Year ended December 31,	
	2006	2005
Gross expenses	19,702	9,204
Capitalized	(2,640)	(2,265)
Recoveries	(2,166)	(2,708)
Net expenses	14,896	4,231
Net expenses, per unit (\$/boe)	2.94	1.34

Interest and Financing Charges

True recorded \$10.7 million of interest and financing charges in 2006 compared to \$1.3 million in the same period of 2005. Financing charges during 2006 were \$1.0 million, with the balance being interest charges. True's net debt at December 31, 2006 of \$275.8 million includes the \$81.6 million liability portion of convertible debentures issued in the second quarter, \$157.9 million of bank debt and the balance a working capital deficiency. The acquisition of Prairie Schooner near the end of the third quarter represents approximately \$74 million of additional net debt as at September 30, 2006, with only 101 days of activity included in the year-to-date results.

Interest and Financing Charges

(\$000s, except where noted)	Years ended December 31,	
	2006	2005
Interest and financing charges	10,665	1,308
Interest and financing charges (\$/boe)	2.11	0.41
Net debt including convertible debentures at quarter end	275,816	111,129
Debt to fourth quarter cash flow from operations ratio annualized	2.1x	1.1x
Net debt excluding convertible debentures at quarter end	194,265	111,129
Debt to fourth quarter cash flow from operations ratio annualized	1.5x	1.1x

Unit-Based Compensation

Non-cash unit-based compensation expense for the year ended December 31, 2006 was \$6.6 million compared to \$5.4 million in 2005. The increase in the 2006 expense reflects the increased staffing levels of True given the additional acquisitions in 2006 and increased production activities requiring appropriate levels of support staff.

For 2005, all options and incentive units held by True Energy Inc. and TKE service providers were either exercised or expired on or before completion of the Arrangement on November 2, 2005, triggering an acceleration of stock based compensation charges. For TKE, these costs were treated as transaction costs and included in the purchase price equation of the acquisition. For True, a total of \$2.2 million of costs were triggered, reflected in the financial statements for 2005 as Plan of Arrangement costs.

Capital Expenditures

True invested \$116.5 million on capital projects during 2006, including cash acquisitions and before property dispositions and non-cash corporate acquisitions, compared to \$116.0 million in 2005. During

the 2006 year, True achieved a 98% success rate in the drilling or participation in 98 (61.5 net) wells, resulting in 72 (41.6 net) natural gas wells, 24 (18.4 net) oil wells and 2 (1.5 net) dry holes. True successfully participated in or drilled 54 (23.7 net) wells in Alberta, and 42 (36.3 net) wells in Saskatchewan. True completed the acquisition of Prairie Schooner on September 22, 2006 at a total cost of \$344.4 million and Shellbridge on June 23, 2006 at a total cost of \$68.8 million. These acquisitions are disclosed in note 3a and 3b, respectively, of the consolidated financial statements.

Capital Expenditures

(\$000s)	Years ended December 31,	
	2006	2005
Lease acquisitions and retention	9,056	8,667
Geological and geophysical	2,399	2,817
Drilling and completion costs	69,218	85,033
Facilities and equipment	18,533	18,964
Exploration and development	99,206	115,481
Corporate and property acquisitions	17,322	490
Total capital expenditures – cash	116,528	115,971
Property dispositions – cash	(24,514)	-
Total net capital expenditures – cash	92,014	115,971
Corporate acquisitions – non-cash	482,875	475,450
Property acquisitions – non-cash ⁽¹⁾	1,817	
Property dispositions – non-cash ⁽²⁾	-	(26,880)
Other ⁽³⁾	3,006	412
Corporate acquisitions and other	487,698	448,982
Total capital expenditures	579,712	564,953

⁽¹⁾ Includes consideration paid for the acquisition of a property interest by issue of trust units.

⁽²⁾ Includes the disposition of properties to Vero under the November 2, 2005 TKE arrangement.

⁽³⁾ Other includes current period's asset retirement obligations and unit based compensation capitalized.

True continues to develop its land base. At December 31, 2006, True has approximately 731,000 net undeveloped acres of land of the total net acreage position of 1,153,000 net acres in Saskatchewan, Alberta, and British Columbia. The addition of Shellbridge in June 2006 and Prairie Schooner in September 2006 added approximately 98,000 and 257,000 net acres, respectively, to the Trust's undeveloped land position.

As at December 31, 2006, the Trust has committed to drill 13 wells in Alberta and 16 wells in Saskatchewan by the end of 2007 pursuant to various farm-in agreements with oil and gas companies. Subsequent to year-end 2006, the Trust has further committed to drill an additional 10 wells in Alberta and 3 in Saskatchewan. Total estimated cost to the Trust for these commitments is \$29.0 million.

Corporate and property acquisitions for cash during 2006 consisted primarily of the acquisition of the Kerrobert, Saskatchewan SAGD heavy oil facility and wells at the end of September 2006 and the purchase of additional property interests in the Willesden Green, Alberta in October 2006.

Dispositions during 2006 consist of two separate oil and gas property sales involving areas outside of the Trust's core areas for future development. On May 31, 2006, True closed the sale of its southeast Saskatchewan oil properties Hartaven and Handsworth for \$24 million cash. On June 20, 2006, True closed the sale of its Peejay and Squirrel area B.C. properties for \$1.2 million cash. The net proceeds received on both property sales after adjustments was an aggregate of \$24.5 million.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion (site restoration) expense for 2006 was \$138.9 million, compared to \$61.4 million in 2005, reflecting the acquisition of TKE in 2005, Shellbridge in June 2006, Prairie Schooner in September 2006 in conjunction with increased production volumes. True has excluded from

the depletion calculation \$99.2 million for undeveloped properties, \$49.3 million for undeveloped land and \$49.9 million for estimated salvage.

Depletion, Depreciation and Accretion Costs

(\$000s, except where noted)	Years ended December 31,	
	2006	2005
Depletion	122,559	51,804
Depreciation	15,251	9,300
Accretion	1,065	336
Total	138,875	61,440
Per unit (\$/boe)	27.45	19.41

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 December 31, 2006 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. As a result of performing this test, a ceiling test impairment loss of \$110.0 million has been recorded as a write-down of petroleum and natural gas properties in the consolidated statements of operations and included in accumulated depletion.

At December 31, 2006, the Trust calculated the ceiling test using prices of \$39.01/bbl for heavy oil, \$66.31/bbl for light and medium gravity oil, and \$56.56/bbl for NGLs, and \$8.33/mcf for natural gas.

Plan of Arrangement Costs

Costs relating to the TKE Arrangement on November 2, 2005 include charges of \$2.2 million of stock-based compensation costs arising from the vesting and exercising of True Energy Inc. options and \$1.4 million of severance and retention costs.

Asset Retirement Obligation

As at December 31, 2006, the Trust has recorded an Asset Retirement Obligation ("ARO") of \$26.6 million, compared to \$10.4 million at December 31, 2005, for future abandonment and reclamation of the Trust's properties. For the 2006 year, the ARO increased by \$1.0 million for accretion expense and \$13.7 million as a result of the Shellbridge and Prairie Schooner acquisitions and included \$1.4 million net changes in estimates for property acquisitions and development activities.

Goodwill

Goodwill represents the excess of total consideration paid plus the future income tax liability less the fair value of the net identifiable assets acquired in each transaction. The goodwill balance prior to impairment of \$169.8 million was derived from two 2005 acquisitions, the second quarter 2006 acquisition of Shellbridge and the third quarter acquisition of Prairie Schooner. The \$97.8 million increase in goodwill during 2006 was a combination of the \$24.0 million goodwill recognized on the Shellbridge acquisition, \$71.6 million recognized on the Prairie Schooner acquisition along with a \$2.2 million purchase price

equation revision for TKE from the under accrual of certain capital, net operating expenditures and transaction costs and adjustments to tax pools from a prior year tax assessment.

Accounting standards require that the goodwill balance be assessed for impairment at least annually or more frequently if events or changes in circumstances indicate that the balance might be impaired.

The Federal Government's announcement of its plans to tax distributions by publicly traded income trust and similar structures resulted in the markets reacting quite strongly to the news. As of November 2, 2006, the market capitalization of the Trust had declined by approximately \$130 million (17.6%) since October 31, 2006. The S&P/TSX Energy Index was off 18% during this same period. The unit price of the Trust additionally declined to December 31, 2006 in light of various factors including further softening of commodity prices and uncertainty associated with the government's announcement. In light of the decline in the market capitalization of the Trust, the Trust has reviewed the valuation of goodwill as of December 31, 2006 based upon the latest available data, including the market capitalization of the Trust, recent commodity prices and an updated reserve engineering report. Based upon this review, an impairment of goodwill of \$169.8 million has been recorded as a non-cash charge to income as of December 31, 2006.

Income Taxes

For the year ended December 31, 2006 the Trust has recorded a provision for capital taxes of \$3.2 million compared to \$3.4 million expensed in 2005. Capital taxes are based on debt and equity levels of the Trust at the end of the year and were slightly lower in 2006 due to the elimination of federal capital tax effective January 1, 2006, offset by increased provincial capital tax. In addition, increased gross sales revenue from Saskatchewan based properties in 2006 was partially offset by recent provincial capital tax reductions. 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 will be based on only provincial capital taxes.

Future income taxes arise from differences between the accounting and tax bases of the operating companies' assets and liabilities. For the year ended December 31, 2006 the Trust recognized a future income tax recovery provision of \$101.1 million compared to a provision of \$2.6 million expensed in 2005. On April 10, 2006 the Alberta government enacted a decrease of 1.5 percent to the provincial corporate tax rate. In addition, on June 6, 2006 the Federal government enacted a two percent decrease to the federal corporate tax rate from January 1, 2008 to January 1, 2010 and an elimination of the 1.12 percent federal surtax at January 1, 2008.

In the Trust's structure, payments are made between the operating subsidiaries and the Trust transferring income and future income tax liability to the unitholders. We expect that if the trust structure of the Trust were maintained, based on existing legislation, that no cash income taxes would be paid by the operating subsidiaries. As such, the future income tax liability recorded on the balance sheet would likely have been recovered through earnings over time. As at December 31, 2006, the operating subsidiaries have a future income tax liability balance of \$123.9 million. Canadian generally accepted accounting principles require that a future income tax liability be recorded when the book value of assets exceeds the balance of tax pools. It further requires that a future tax liability be recorded on an acquisition when a corporation acquires assets with associated tax pools that are less than the purchase price.

At December 31, 2006 the Trust and operating subsidiaries of the Trust had approximately \$498 million (2005 - \$180 million), net of partnership deferrals, in tax pools available for deduction against future earnings as follows:

(\$000s)	Trust	Operating subsidiaries	Total
Intangible resource pools (net of partnership deferrals)	\$ 15,015	\$ 306,454	\$ 321,559
Undepreciated capital cost	-	158,132	158,132
Loss carryforwards (expire through 2026)	-	5,624	5,624
Unit issue costs	5,126	6,958	12,084
Other	-	271	271
	\$ 20,231	\$ 477,439	\$ 497,670

The October 31, 2006 announcement of the Tax Fairness Plan by the Federal Government anticipates a distribution tax on distributions from publicly traded income trusts and similar structures. For existing income trusts and limited partnerships, the government is proposing a four-year transition period. As such, the Trust would not be subject to the new measures until the 2011 taxation year provided the Trust continues to meet certain requirements. Refer to "Business Risks and Uncertainties" for further details.

The government's plans must first be enacted in Parliament and it may be some time before the plans, translated into legislation, are substantially enacted, particularly given the fact that there is a minority government in place. As such, as at December 31, 2006, and until third reading of the Bill in Parliament, current and future income taxes have not been adjusted as a result of this recent announcement. If implemented as currently proposed, the Trust would be required to recognize in its accounts, in the period in which the change is substantively enacted, future income taxes on temporary differences in the Trust.

Distributions

Trust unitholders who held their trust units throughout 2006 received distributions of \$2.64 per unit. For the year ended December 31, 2006 the Trust declared \$124.4 million in total distributions as follows:

<i>(\$000s, except per unit amount)</i>	Distribution Per Unit	Total
Year ended December 31, 2006		
Distributions paid	\$ 2.64	\$ 124,355

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	Taxable Portion	Return of Capital
2005 (two months) ⁽²⁾	\$ 0.480	\$ 0.456	\$ 0.024
2006 year to date ⁽³⁾	2.640	2.033	0.607
Cumulative	\$3.120	\$2.489	\$0.631

⁽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.

⁽³⁾ For Canadian tax purposes, 2006 distributions were determined to be 77 percent taxable and 23 percent a tax deferred return of capital in the hands of Canadian unitholders. In Canada, the tax deferred portion would usually be treated as an adjustment to the cost base of the units.

In consultation with its U.S. tax advisors, True believes that the trust units should be "qualified dividends" for U.S. federal purposes. As such, the portion of distributions made during 2006 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 trust units. Please view our March 15, 2006 press release addressing this.

Monthly Distributions

Actual distributions paid and declared per Trust unit along with anticipated relevant payment dates for 2006 are as follows:

Ex-distribution Date	Record Date	Payment Date	Distribution per unit
December 28, 2005	December 31, 2005	January 16, 2006	\$ 0.24
January 27, 2006	January 31, 2006	February 15, 2006	0.24
February 24, 2006	February 28, 2006	March 15, 2006	0.24
March 29, 2006	March 31, 2006	April 17, 2006	0.24
April 24, 2006	April 26, 2006	May 15, 2006	0.24
May 25, 2006	May 29, 2006	June 15, 2006	0.24
June 23, 2006	June 27, 2006	July 17, 2006	0.24
July 24, 2006	July 26, 2006	August 15, 2006	0.24
August 24, 2006	August 28, 2006	September 15, 2006	0.24
September 22, 2006	September 26, 2006	October 16, 2006	0.24
October 25, 2006	October 27, 2006	November 15, 2006	0.18
November 24, 2006	November 28, 2006	December 15, 2006	0.18
December 27, 2006	December 31, 2006	January 15, 2007	0.12

The Management and Board of the Trust continuously assesses distribution levels, in light of commodity prices and other factors, and announces the distribution per unit amount on a monthly basis.

In 2006, the distributions were funded from a combination of cash flows from operating activities, the proceeds from a convertible debenture offering, and the DRIP program.

The Board of True maintained ten consecutive monthly distributions of \$0.24 per unit through to October 16, 2006. In a press release dated October 10, 2006, the Trust announced that the cash distribution for the month of October would be \$0.18 per unit, to be paid on November 15, 2006 to all unitholders of record as of October 27, 2006. Further, in a press release dated December 14, 2006, the Trust announced that the cash distribution for the month of December would be \$0.12 per unit, to be paid on January 15, 2007 to all unitholder of record on December 31, 2006. These reductions in the monthly distribution were determined to be prudent by the Board to reflect weakening commodity prices, both in the current spot market and in the forward strip prices and to strengthen the balance sheet. Additionally, a monthly distribution declared and paid on February 15, 2007 was \$0.12 per unit, with a further announced distribution of \$0.12 per unit to be paid on March 15, 2007.

On January 15, 2007, the Trust announced its intention to convert to a growth oriented, dividend paying intermediate exploration and production company (the "Reorganization"), which will be voted upon by securityholders at an Annual and Special Meeting (the "Meeting") to be held on March 30, 2007. Further as announced on February 15, 2007, the Board of True has determined that no distribution will 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.

Combined with a capital efficient growth strategy, True intends to establish a dividend policy to take effect following the completion of the Reorganization of True into a corporation. The initial dividend proposed by True as a corporation is to be set at \$0.02/share per month to be paid quarterly.

Should the Reorganization not be approved by True securityholders, the Board of True will meet in April 2007 to determine the level of distribution to be paid by the Trust.

Distribution Reinvestment Plan

Effective March 27, 2006, True adopted a Premium DistributionTM Reinvestment, Distribution Reinvestment and Optional Trust Unit Purchase Plan (the "Plan"). The Plan amends, restates and

replaces in its entirety the distribution reinvestment and optional trust unit purchase plan (the "Old Plan") of True dated December 1, 2004, which was implemented by TKE. The Plan allows eligible unitholders of True to direct that their cash distributions be reinvested in additional trust units at 95% of the Average Market Price (as defined in the Plan) on the applicable distribution payment date. The Plan further allows eligible unitholders to elect, under the Premium DistributionTM component of the Plan, to have these additional trust units delivered to the designated Plan broker in exchange for a premium cash distribution equal to 102% of the cash distribution that such unitholders would otherwise have received on the applicable distribution payment date if they did not participate in the Plan (subject to proration in certain events as provided in the Plan.) Canaccord Capital Corporation acts as the Plan broker for the Premium DistributionTM component of the Plan.

In addition, the Plan allows those unitholders who participate in either the regular distribution reinvestment component or the Premium DistributionTM component of the Plan to purchase additional trust units from treasury at a purchase price equal to the Average Market Price (with no discount) in minimum amounts of \$2,000 per remittance up to a maximum aggregate amount of \$50,000 per month by any one unitholder, in any calendar month, all subject to an overall annual limit of 2% of the total number of outstanding trust units. The Trust reserves the right to limit the amount of any new equity available under the Plan on any particular distribution date and thus participants may be pro-rated in certain circumstances.

Participation during the first eight months of the plan averaged approximately 48%.

On November 16, 2006, the Trust announced the suspension of equity available for reinvestment under the Plan until further notice.

Foreign Ownership Update

Based on information from Trust records and information provided by intermediaries holding Trust units for others, we estimate that, as of January 31, 2007 approximately 32 percent of our Unitholders are non-Canadian residents with the remaining 68 percent being Canadian residents. True's Trust Indenture provides that not more than 40 percent of its Units can be held by non-Canadian residents.

Liquidity and Capital Resources

True's net debt as at December 31, 2006 was \$275.8 million, \$4.9 million drawn on a demand operating facility, \$153.0 million drawn on a revolving term credit facility, \$81.6 million in convertible debentures (liability component) and the balance a net working capital deficiency.

On October 2, 2006 the existing \$150 million credit facility was replaced by a \$15 million demand operating facility provided by one Canadian bank and a \$210 million extendible revolving term credit facility syndicated by the Canadian chartered bank, a U.S. bank, a foreign bank and one institutional lender. The revolving period on the new revolving term credit facility ends on June 29, 2007, unless extended for a further 364 day period. Should the facilities not be renewed they convert to 366 day non-revolving term facilities on the renewal date. Further details of the revised credit facility are disclosed in note 6 of the consolidated financial statements. As at December 31, 2006, there is approximately \$67 million available under this lending facility.

Management expects to be able to fund the capital expenditure program for 2007 using cash flow from operations, available credit facilities, the proceeds from the expected sale of certain non-core assets, and/or the reduced distributions as a result of the planned conversion to a corporation. If cash flows are other than projected, capital expenditure levels will be adjusted. The practice of continually monitoring

spending opportunities in comparison to expected cash flow levels allows for adjustments to the capital program as required.

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

The 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 the weighted average trading price of the trust units.

As at February 21, 2007 the Trust had outstanding a total of 5,252,333 incentive units exercisable at an average exercise price of \$14.04 per unit, 403,536 exchangeable shares (convertible, as at February 21, 2007 into an aggregate of 297,739 trust units, subject to further adjustments based on distributions made on trust units) and 70,275,703 trust units.

On February 13, 2007, True announced it had identified certain small, non-core properties, for possible disposition. The planned disposition is comprised of up to 950 boe/d of largely non-operated production. The proceeds will be used to fund capital expenditures and pay down debt.

Commitments

As at December 31, 2006, the Trust has committed to drill 13 wells in Alberta and 16 wells in Saskatchewan by the end of 2007 pursuant to various farm-in agreements with oil and gas companies. Subsequent to year-end 2006, the Trust has further committed to drill an additional 13 wells in Alberta and 5 in Saskatchewan. The total estimated cost to the Trust for these commitments is \$30.2 million.

Leases relating to gas compression and other equipment with initial costs totaling \$1.2 million (2005 - \$1.2 million) have been classified as capital leases and are included in property, plant and equipment. The remaining capital lease obligation of \$111 thousand has an implicit interest rate consisting of a variable Bankers Acceptance Rate + 3.7%; and will be repaid in 2007.

The Trust has further committed to various corporate sponsorships extending to June 2010 at an estimated combined cost of up to \$172,000.

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

(\$000s) Year	Gross Amount	Expected Recoveries	Net Amount
2007	1,669	271	1,398
2008	1,390	285	1,105
2009	1,000	285	715
2010	285	285	-
2011	285	285	-

Business Prospects and 2007 Outlook

Since its formation in September 2000, True Energy Inc. has experienced significant growth in its production and land base. The Trust continues to develop its core assets and conduct some exploration programs utilizing its large inventory of geological prospects. In addition, the Trust will continue to explore potential acquisition opportunities. Currently, the Trust's producing properties are located in Saskatchewan, Alberta and British Columbia.

Late in September 2006, the Trust completed the purchase of a facility in the Kerrobert, Saskatchewan area and wells which has allowed the Trust to begin implementation of the SAGD phase of the project. Continuing through June 2007, the Trust plans to convert a number of existing wells to steam injectors and drill additional wells that will be used as producing well bores. The facility is currently running at 600 bbls/d of heavy oil production with capacity of approximately 5,000 bbls/d. Also included in the acquisition were three sections of land on which True has identified a number of development and exploration opportunities.

Capital expenditure levels will be adjusted as appropriate. Under the Trust's assumption of approval of the conversion to a corporation, the Trust currently anticipates spending approximately \$120 million in 2007 focused on the implementation of the Kerrobert SAGD program and further development of its west central Alberta properties, most notably the Ferrier, Willesden Green and Brazeau areas.

The Trust currently anticipates that 2007 year average production will be approximately 20,500 boe/d, weighted approximately 64% toward natural gas. True further anticipates the US\$/Cdn.\$ exchange rate to average 0.90 through the 2007 year.

The Trust continues to maintain a large undeveloped land base of approximately 1.1 million (0.7 million net) acres and has identified a multi-year drilling inventory of over 600 net locations.

Financial Reporting Update

Effective January 1, 2007, True will be required to adopt the accounting rules 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" will also be effective for True on January 1, 2007. An additional Handbook section related to disclosure and presentation of financial instruments (Section 3861) is not effective until 2008 for the Trust. The new accounting pronouncements that are effective for 2007 determine how reporting entities recognize and measure financial assets, financial liabilities and non-financial derivatives.

New Section 3855 sets out comprehensive requirements for recognition and measurement of financial instruments. Under this standard, an entity would recognize a financial asset or liability only when the entity becomes a party to the contractual provisions of the financial instrument. Financial assets and financial liabilities would, with certain exceptions, be initially measured at fair value.

In conjunction with the new standard on financial instruments as discussed above, CICA Handbook Section 1530 (Comprehensive Income) has also been issued. A statement of comprehensive income would be included in a full set of financial statements for both interim and annual periods under this new standard. Comprehensive income is defined as the change in equity (net assets) of an enterprise during a period from transactions and other events and circumstances from non-owner sources. The new statement would present net income and each component to be recognized in other comprehensive income. Likewise, the CICA has issued Handbook Section 3251 (Equity) which requires the separate presentation of: the components of equity (retained earnings, accumulated other comprehensive income

("AOCI"), the total retained earnings and accumulated other comprehensive income, contributed surplus, unitholders' capital and reserves); and the changes in equity arising from each of these components of equity.

Effective January 1, 2007, the Trust will no longer be applying the former Accounting Guideline 13 hedge accounting to its existing crude oil and natural gas hedge contracts as the Trust will follow the recommendations of Section 3865. On January 1, 2007, the Trust will mark-to-market the existing positions and will record the fair values of approximately \$8.2 million on the Consolidated Balance Sheet as a deferred asset, with a corresponding increase to AOCI. Subsequent changes in the fair value of the positions will be recorded in net income.

Business Risks and Uncertainties

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

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

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

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

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

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

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

On October 31, 2006 the Federal Minister of Finance proposed to apply a tax at the trust level on distributions of certain income from publicly traded mutual fund trusts and similar structures at rates of tax comparable to the combined federal and provincial corporate tax and to treat such distributions as dividends to the unitholders (the "October 31 Proposals"). On December 21, 2006 the Federal Minister of Finance released draft legislation to implement the October 31, 2006 Proposals pursuant to which, commencing January 1, 2011 (provided the Trust only experiences "normal growth" and no "undue expansion" before then) certain distributions from the Trust which would have otherwise been taxed as ordinary income generally will be characterized as dividends in addition to being subject to tax at corporate rates at the trust level. Assuming the October 31 Proposals are ultimately enacted in their form, the implementation of such legislation would be expected to result in adverse tax consequences to the Trust and certain unitholders (including most particularly unitholders that are tax deferred or non-residents of Canada) and may impact cash distributions from the Trust. It is not known at this time when the October 31 Proposals will be enacted by Parliament, if at all, or whether the October 31 Proposals will be enacted in the form currently proposed.

On January 15, 2007, the Trust announced the proposed Reorganization and its intention to convert to a growth oriented, dividend paying intermediate exploration and production company, pursuant to which holders of trust units of the Trust would receive an equal number of shares from the newly formed corporation who will hold the assets previously held directly or indirectly by the Trust. The exchangeable shares will also be exchanged for common shares of the newly formed corporation based on the conversion ratio thereof. Completion of the Reorganization is subject to approval of securityholders of the Trust at the meeting of securityholders to be held to consider the matter and will be subject to receipt of all regulatory and other approvals. There is no assurance that securityholder or other approvals required for completion of the Reorganization will be received and that the Reorganization will be completed.

See also the risk factors described in the Trust's Annual Information Form.

Critical Accounting Estimates

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

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

The Trust uses the full cost method of accounting for oil and gas properties. Generally, all costs of exploring and developing oil and natural gas reserves are capitalized and depleted against associated oil

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

The discounted, expected future cost of statutory, contractual or legal obligations to retire long-lived assets are recorded as an Asset Retirement Obligation ("ARO") liability with a corresponding increase to the carrying amount of the related asset. The recorded ARO liability increases over time to its future amount through accretion charges to earnings. Revisions to the estimated amount or timing of the obligations are reflected as increases or decreases to the ARO liability. Amounts capitalized to the related assets are amortized to income consistent with the depletion or depreciation of the underlying asset.

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

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

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

Legal, Environmental Remediation and Other Contingent Matters

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

Controls and Procedures

Disclosure Controls and Procedures

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Trust is accumulated and communicated the Trust's management as appropriate to allow timely decisions regarding required disclosure. The Trust's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by the

Trust's annual filings for the most recently completed financial year, that the Trust's disclosure controls and procedures as of the end of such period are effective to provide reasonable assurance that material information related to the Trust, including its consolidated subsidiaries, is made known to them by others within those entities, particularly during the period in which the annual filings are being prepared.

Internal Controls over Financial Reporting

The Trust's Chief Executive Officer and Chief Financial Officer have designed or caused to be designed under their supervision internal controls over financial reporting related to the Trust, including its consolidated subsidiaries, to provide reasonable assurance regarding the reliability of the Trust's financial reporting and the preparation of financial statements together with the other financial information 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. During 2006, the Trust engaged external consultants to assist in documenting and assessing the Trust's design of internal controls over financial reporting. No material changes in the Trust's internal control over financial reporting were identified during the three months ended December 31, 2006, that has materially affected, or are reasonably likely to materially affect, the Trust's internal control of financial reporting.

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

National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109") Update

On March 30, 2004 National Instrument 52-109 came into force in various jurisdictions with a requirement for a certification process over disclosure and internal controls over financial reporting. Initially, an internal control design was required to provide reasonable assurance regarding the reliability of the financial reporting and preparation of financial statements in accordance with Canadian GAAP, with which the Trust is in compliance at December 31, 2006. Subsequently, an evaluation of the effectiveness over the internal control design was to have been certified by the Chief Executive Officer and Chief Financial Officer for the year ended December 31, 2007. The Canadian Securities Administrators ("CSA") issued a notice on February 9, 2007 proposing that requirements under NI 52-109 be extended becoming effective for the Trust at year end December 31, 2008. This extension is intended to allow significant lead time for issuers to plan and implement efficiently the activities required to support the additional certifications and disclosures relating to internal controls over financial reporting. The CSA further indicates that they plan, by the end of March 2007, to seek all necessary approvals to publish revisions to NI 52-109 for public comment. The Trust will continue to work diligently to ensure compliance with this requirement by December 31, 2008.

Sensitivity Analysis

The table below shows sensitivities to cash flow as a result of product price and operational changes. This is based on actual 2006 prices received for the fourth quarter of 2006 and average production volumes of 19,700 boe/d during that period, as well as the same level of debt outstanding at December 31, 2006. Diluted weighted average trust units is based upon the fourth quarter of 2006. These sensitivities are approximations only, and not necessarily valid under other significantly different production levels or product mixes. Hedging activities can significantly affect these sensitivities. Changes in any of these parameters will affect cash flow as shown in the table below:

Sensitivity Analysis	Cash Flow from Operations (annualized) (\$000s)	Cash Flow from Operations Per Diluted Unit (\$)
Change of US \$1/bbl WTI	2,300	0.03
Change of US \$0.10/ mcf	2,300	0.03
Change of US \$0.01 Cdn/ US exchange rate	2,500	0.03
Change in prime of 1%	1,300	0.02

Selected Quarterly Consolidated Information

The following table sets forth selected consolidated financial information of the Trust for the eight most recently completed quarters at the end of 2006.

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 earnings (loss)	3,259	12,243	1,652	(250,718)
Net earnings (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
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 earnings (loss)	1,030	3,130	6,502	3,228
Net earnings (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.

Selected Annual Information

Years Ended December 31, (\$000s, except per unit amounts)	2006	2005 ⁽²⁾	2004 ⁽²⁾
Revenues before royalties and hedging	220,913	161,670	67,948
Cash flow from operations ⁽¹⁾	90,391	87,137	33,945
Cash flow from operations per unit ⁽¹⁾			
Basic	\$1.91	\$3.53	\$2.28
Diluted	\$1.87	\$3.47	\$2.23
Net earnings (loss)	(233,564)	13,890	8,960
Net earnings (loss) per unit			
Basic	\$(4.95)	\$0.56	\$0.60
Diluted	\$(4.95)	\$0.55	\$0.59
Net capital expenditures (cash)	92,014	115,971	54,919
Total assets	1,016,658	731,129	108,339
Total net debt	275,816	111,129	22,158
Long-term financial liabilities			
Obligations under capital lease	-	54	-
Capital taxes payable	-	1,700	1,364
Future income taxes	123,861	146,729	13,209
Asset retirement obligations	26,605	10,457	3,951
Exchangeable shares of Subsidiary	4,153	9,709	-
Production (boe/d)	13,861	8,672	5,048
Distributions declared	124,355	17,361	-
Distributions per unit ⁽²⁾	\$2.64	\$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.

TRUE ENERGY TRUST
CONSOLIDATED BALANCE SHEETS

As at December 31

(\$000s)	2006	2005
ASSETS		
Current assets		
Accounts receivable	\$ 73,199	\$ 57,276
Deposits and prepaid expenses	7,928	1,806
	81,127	59,082
Property, plant and equipment (note 4)	931,979	600,077
Deferred financing charges (note 7)	3,552	-
Goodwill (note 5)	-	71,970
Total assets	\$1,016,658	\$ 731,129
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	\$ 107,431	\$ 88,270
Distribution payable to unitholders	8,433	8,677
Capital taxes payable	1,513	1,641
Current portion of obligations under capital lease (note 8)	111	258
Bank debt (note 6)	-	71,365
	117,488	170,211
Obligations under capital lease (note 8)	-	54
Long-term debt (note 6)	157,904	-
Capital taxes payable	-	1,700
Convertible debentures (note 7)	81,551	-
Asset retirement obligations (note 9)	26,605	10,457
Future income taxes (note 14)	123,861	146,729
Total liabilities	507,409	329,151
NON-CONTROLLING INTEREST		
Exchangeable shares of subsidiary (note 10)	4,153	9,709
UNITHOLDERS' EQUITY		
Unitholders' capital (note 11)	876,904	418,968
Equity component of convertible debentures (note 7)	5,119	-
Contributed surplus (note 12)	12,818	5,127
Deficit	(389,745)	(31,826)
Total unitholders' equity	505,096	392,269
Total liabilities and unitholders' equity	\$ 1,016,658	\$ 731,129

COMMITMENTS (note 17)

SUBSEQUENT EVENT (note 19)

See accompanying notes to the consolidated financial statements.

TRUE ENERGY TRUST
CONSOLIDATED STATEMENTS OF OPERATIONS AND DEFICIT

For the years ended December 31

(\$000s)	2006	2005
REVENUES		
Petroleum and natural gas sales	\$ 220,913	\$ 161,670
Royalties	(51,816)	(40,818)
Gain (loss) on commodity contracts	2,639	(217)
	<u>171,736</u>	<u>120,635</u>
EXPENSES		
Production	46,685	21,219
Transportation	6,517	3,525
General and administrative	14,896	4,231
Interest and financing charges	10,665	1,308
Unit-based compensation (note 12)	6,597	5,402
Depletion, depreciation and accretion (note 4)	138,875	61,440
Write-down of petroleum and natural gas properties (note 4)	110,000	-
Goodwill impairment (note 5)	169,768	-
Plan of Arrangement costs (note 4(c))	-	3,561
	<u>504,003</u>	<u>100,686</u>
EARNINGS (LOSS) BEFORE TAXES	(332,267)	19,949
TAXES (note 14)		
Current income taxes	-	7
Capital taxes	3,245	3,394
Future income taxes (recovery)	(101,145)	2,636
	<u>(97,900)</u>	<u>6,037</u>
NET EARNINGS (LOSS) BEFORE NON-CONTROLLING INTEREST	(234,367)	13,912
Non-controlling interest (note 10)	(803)	22
NET EARNINGS (LOSS)	(233,564)	13,890
Deficit, beginning of year	(31,826)	(6,090)
Transfer of assets pursuant to Plan of Arrangement (note 3(d))	-	(22,265)
Distributions declared	(124,355)	(17,361)
Deficit, end of year	<u>\$ (389,745)</u>	<u>\$ (31,826)</u>
Net earnings (loss) per trust unit (note 15)		
Basic	\$ (4.95)	\$ 0.56
Diluted	\$ (4.95)	\$ 0.55

See accompanying notes to the consolidated financial statements.

TRUE ENERGY TRUST
CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31

(\$000s)

	2006	2005
Cash provided by (used in):		
CASH FLOW FROM OPERATING ACTIVITIES		
Net earnings (loss)	\$ (233,564)	\$ 13,890
Items not involving cash:		
Non-controlling interest (note 10)	(803)	22
Depletion, depreciation and accretion (note 4)	138,875	61,440
Write-down of petroleum and natural gas properties (note 4)	110,000	-
Goodwill impairment (note 5)	169,768	-
Unit-based compensation (note 12)	6,597	7,552
Amortization of deferred financing charges	437	-
Accretion on convertible debentures	420	-
Future income taxes (recovery) (note 14)	(101,145)	2,636
Capital taxes (note 14)	(194)	1,597
	<u>90,391</u>	<u>87,137</u>
Change in non-cash working capital (note 13)	36,925	21,665
	<u>127,316</u>	<u>108,802</u>
CASH FLOW FROM (USED IN) FINANCING ACTIVITIES		
Increase in bank debt	19,166	15,169
Obligations under capital lease	(201)	(32)
Issuance of convertible debentures (note 7)	86,250	-
Deferred financing charges (note 7)	(3,989)	-
Issuance of common shares	-	11,397
Share and unit issue costs	(2,410)	(3,462)
Payment of cash component of distributions	(81,991)	(10,766)
	<u>16,825</u>	<u>12,306</u>
Change in non-cash working capital (note 13)	143	(10,664)
	<u>16,968</u>	<u>1,642</u>
CASH FLOW FROM (USED IN) INVESTING ACTIVITIES		
Additions to property, plant and equipment	(116,528)	(115,971)
Corporate transaction costs (note 3)	(2,083)	(4,174)
Proceeds on sale of property, plant and equipment	24,514	5,012
	<u>(94,097)</u>	<u>(115,133)</u>
Change in non-cash working capital (note 13)	(55,405)	4,689
	<u>(149,502)</u>	<u>(110,444)</u>
Cash acquired on corporate acquisition (note 3)	5,218	-
Change in cash	-	-
Cash, beginning of year	-	-
Cash, end of year	\$ -	\$ -

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Years ended December 31, 2006 and 2005

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. ("Vero"). The former shareholders of True Energy Inc. control approximately 71% of the Trust and substantially all of the Trust's new management team is the former management of True Energy Inc.

The TKE Arrangement resulted in True Energy Inc. shareholders receiving, for each True Share held: (i) 0.5 of a pre-consolidated trust units (0.25 of a post-consolidated trust unit); (ii) 0.10 of a Vero Share; and (iii) one Vero arrangement warrant.

Concurrent with approval of the TKE Arrangement, TKE received approval from Unitholders at the TKE unitholder meeting to consolidate its existing outstanding trust units on a one-for-two (1:2) basis and to change its name to "True Energy Trust". Under the TKE Arrangement, True Energy Inc. and TKE Energy Inc. were amalgamated to form the new administrator of the Trust under the name True 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.

The conversion of True Energy Inc. to the Trust has been accounted for as a reverse takeover of TKE and a continuity of interests of True Energy Inc. Prior to the TKE Arrangement on November 2, 2005, the consolidated financial statements included the accounts of True Energy Inc. and its subsidiaries and partnership. After giving effect to the TKE Arrangement, the consolidated financial statements include the accounts of the Trust, its subsidiaries and partnerships.

The term “units” has been used to identify both the trust units and the exchangeable shares of the Trust issued on or after November 2, 2005 as well as the common shares of True Energy Inc. outstanding prior to the TKE Arrangement on November 2, 2005.

On January 15, 2007, the Trust announced its intention to convert into an intermediate exploration and production company as disclosed in note 19 of these financial statements.

2. SIGNIFICANT ACCOUNTING POLICIES

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

a. Principles of Consolidation

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

b. Revenue Recognition

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

c. Joint Interests

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

d. Petroleum and Natural Gas Properties

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

e. Depletion and Depreciation

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

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

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

f. Ceiling Test

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

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

g. Goodwill

Goodwill is recognized on corporate acquisitions when the total purchase price exceeds the fair value of the net identifiable assets of the acquired company. The carrying value of goodwill is assessed for impairment annually at year-end, or more frequently if events occur that could result in an impairment. Impairment is verified by comparing the carrying amount of the goodwill for the reporting entity to the excess of the Trust's fair value of its publicly traded trust units over the related book value. If the fair value of the Trust's equity is less than the book value, impairment is measured by allocating the fair value of the Trust to its identifiable assets and liabilities at their fair values. The excess of this allocation represents the fair value of goodwill. The excess of the book value of goodwill over this implied fair value is then recognized through the statement of income as an impairment. Impairment is charged to income in the period in which it occurs. Goodwill is stated at cost less impairment and is not amortized.

h. Cash and Cash Equivalents

Cash and cash equivalents include bank balances and highly liquid temporary money market instruments with original maturities of three months or less.

i. Asset Retirement Obligations

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

j. Prepaid Contracts

Advance payments received under prepaid contracts for oil and gas not delivered are deferred and are recognized as revenue when deliveries are made. Revenue is recognized on a straight-line basis by dividing the advance payment by the total contracted volumes.

k. Unit-based Compensation Plan

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

l. Income Taxes

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

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. As the Trust distributes all of its taxable income to the unitholders and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for income taxes has been made in the Trust.

m. Exchangeable Shares of Subsidiary

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

n. Derivative Financial Instruments

The Trust uses derivative financial instruments from time to time to hedge its exposure to commodity price and foreign exchange fluctuations. The Trust does not enter into derivative financial instruments for trading or speculative purposes.

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

derivative financial instruments to determine their effectiveness as hedges, both at inception and over the term of the instruments.

The Trust enters into hedges of its exposure to petroleum and natural gas commodity prices by entering into crude oil and natural gas swap contracts, options or collars, when it is deemed appropriate. If the derivatives are deemed not to qualify as hedges under Canadian accounting standards, the fair values of the derivative financial instruments are recorded as assets or liabilities on the balance sheet. Otherwise, the derivative contracts are accounted for as hedges and are not recognized on the balance sheet. Realized gains and losses on these contracts are then recognized in petroleum and natural gas revenue and cash flows in the same period in which the revenues associated with the hedged transaction are recognized. Premiums paid or received are deferred and amortized to earnings over the term of the contract.

o. Basic and Diluted per Trust Unit Calculations

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

p. Measurement Uncertainty

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

3. ACQUISITIONS/DISPOSITIONS

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:

(\$000's)

Cost of acquisition:	
Trust units issued	\$ 342,870
True transaction costs	1,563
	\$ 344,433
Allocated at estimated fair values:	
Accounts receivable	\$ 32,295
Deposits and prepaid expenses	1,075
Property, plant and equipment	435,346
Goodwill (note 5)	71,601
Bank debt	(67,373)
Accounts payable and accrued liabilities	(42,636)
Future income taxes	(73,467)
Asset retirement obligations	(12,408)
	\$ 344,433

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:

(\$000's)

Cost of acquisition:	
Trust units issued	\$ 68,299
True transaction costs	520
	\$ 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 (note 5)	24,017
Accounts payable and accrued liabilities	(13,485)
Future income taxes	(3,330)
Asset retirement obligations	(1,296)
	\$ 68,819

c. Acquisition of TKE Energy Trust

On November 2, 2005 True Energy Inc. and TKE entered into a business combination whereby True Energy Inc. acquired TKE in a reverse takeover, changing to True Energy Trust, and a publicly listed exploration focused company, Vero Energy Inc., pursuant to a Plan of Arrangement. The former shareholders of True Energy Inc. controlled approximately 71% of the Trust and substantially all of the former management of True Energy Inc. formed the Trust's new management team.

The TKE Arrangement resulted in True shareholders receiving, for each True Share held: (i) 0.5 of a pre-consolidated trust units (0.25 of a post-consolidated trust unit); (ii) 0.10 of a Vero Share; and (iii) one Vero arrangement warrant.

To effect the TKE Arrangement, for accounting purposes only, all of the issued and outstanding trust units, being 20,708,128 trust units, of TKE were treated as acquired by True Energy Inc. The transaction value was based upon the adjusted weighted average trading price of True Energy Inc. common shares for the two days prior to the transaction announcement on August 23, 2005, of \$5.04, plus the assumption of TKE's debt. The transaction was accounted for using the purchase method, with the excess purchase price over the fair value of net identifiable assets acquired of approximately \$42.4 million being allocated to goodwill.

The purchase equation was adjusted during 2006 to reflect certain net under accruals for operating income and capital expenditures and transaction costs and adjustments from tax assessments relating to the period prior to November 2, 2005. As a result, transactions costs were increased by \$0.5 million, total net accounts receivable was reduced by \$0.7 million, future income tax liability was increased by \$1.0 million and goodwill was increased by \$2.2 million.

The purchase price equation is as follows:

(\$000s)

Cost of acquisition:	
Trust units issued	\$ 196,214
Transaction costs	2,505
	<u>\$ 198,719</u>
Allocated at estimated fair values:	
Accounts receivable	\$ 10,833
Deposits and prepaid expenses	1,152
Property, plant and equipment	291,706
Goodwill (note 5)	44,573
Accounts payable and accrued liabilities	(17,912)
Bank debt	(32,077)
Distribution payable	(2,382)
Obligation under capital lease	(343)
Non-controlling interest	(10,351)
Future income taxes	(80,320)
Asset retirement obligations	(6,160)
	<u>\$ 198,719</u>

In accordance with the TKE Arrangement, all stock options of True Energy Inc. vested and were exercised or expired resulting in recognition of previously unamortized stock-based compensation of \$2.2 million being charged to Plan of Arrangement costs in earnings for 2005. In addition, the Trust incurred \$1.4 million in severance and retention costs that are included in Plan of Arrangement costs within earnings for 2005.

d. Disposition to Vero Energy Inc.

Under the TKE Arrangement, True Energy Inc. transferred to Vero certain prospective natural gas weighted assets and undeveloped land at their net book value. A future tax asset was transferred as the result of disposing of petroleum and natural gas properties with a net book value of \$26.9 million compared to tax pools of \$27.9 million. The details are as follows:

(\$000s)

Petroleum and natural gas properties	\$ 26,880
Asset retirement capital	318
Future income tax asset	384
Total assets transferred	27,582
Asset retirement obligation	(318)
Bank indebtedness assumed	(5,000)
Net assets transferred and charged to deficit	<u>\$ 22,264</u>

In conjunction with the TKE Arrangement, the Trust entered into a Transitional Services Agreement ("Agreement") with Vero where the Trust provided personnel and certain administrative and technical services in connection with the management, development, exploitation and operation of the assets of Vero. The initial term of the Agreement was for a period of 3 months after the effective date of the TKE Arrangement, however, this Agreement has been extended to April 1, 2006, at which time it expired. The Trust provided these services to Vero on an expense reimbursement basis, based on Vero's monthly capital activity and production levels relative to the combined capital activity and production levels of both the Trust and Vero. Total expenses reimbursed by Vero for the three month period ended March 31, 2006 were \$0.1 million.

e. Acquisition of Meridian Energy Corporation

Effective March 15, 2005, True Energy Inc. acquired all of the issued and outstanding common shares of Meridian Energy Corporation ("Meridian"), a public company, involved in the exploration, development and production of oil and natural gas in central Alberta. The consideration offered was \$0.6 million and 0.91 of a True Energy Inc. common share for each Meridian common share resulting in 35,111,184 True Energy Inc. shares issued as at March 31, 2005 and an additional 638,747 shares issued in April and June 2005. The value of the transaction, based on an adjusted average share price for the common shares of True Energy Inc. of \$4.20 at January 19, 2005, was \$152.2 million (including \$1.4 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 \$29.6 million, which was reflected as goodwill. The accounts include the results of Meridian effective March 15, 2005, the date the majority of Meridian shares were taken up and exchanged for True Energy Inc. common shares.

The purchase equation was adjusted at December 31, 2005 to reflect revised estimates for tax information regarding expected temporary difference reversals. As a result, the future tax liability was decreased by \$3.6 million and goodwill was also decreased by the same amount.

The purchase price equation is as follows:

<u>(\$000's)</u>	
Cost of acquisition:	
Common shares issued	\$ 150,150
True transaction costs	1,411
Cash to shareholders	620
	\$ 152,181
Allocated at estimated fair values:	
Accounts receivable	\$ 15,186
Deposits and prepaid expenses	89
Property, plant and equipment	183,744
Goodwill (note 5)	29,577
Accounts payable and accrued liabilities	(14,119)
Bank debt	(11,389)
Future income taxes	(49,915)
Asset retirement obligations	(992)
	\$ 152,181

4. PROPERTY, PLANT AND EQUIPMENT

(\$000s)

December 31, 2006	Cost	Accumulated depletion and depreciation	Net book value
Petroleum and natural gas properties	\$1,314,374	\$ 384,110	\$ 930,264
Office furniture and equipment	2,588	873	1,715
	\$1,316,962	\$ 384,983	\$ 931,979
December 31, 2005			
Petroleum and natural gas properties	\$ 735,788	\$ 136,539	\$ 599,249
Office furniture and equipment	1,461	633	828
	\$ 737,249	\$ 137,172	\$ 600,077

The Trust has excluded from the depletion calculation \$99.2 million (2005 - \$36.3 million) for undeveloped properties and \$49.3 million (2005 - \$24.1 million) for undeveloped land.

In 2006, the Trust capitalized \$2.6 million (2005 - \$2.3 million) of general and administrative expenses and \$1.1 million (2005 - \$1.4 million) of unit-based compensation expense directly related to exploration and development activities.

The Trust performed a ceiling test calculation at December 31, 2006 resulting in undiscounted cash flows from proved reserves plus the carrying cost less impairment allowance of 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 less impairment allowance of unproved properties exceeded the carrying value of its petroleum and natural gas properties. As a result of performing this test, a ceiling test impairment loss of \$110.0 million has been recorded as a write-down of petroleum and natural gas properties in the consolidated statements of operations and is included in accumulated depletion.

The prices used in the ceiling test evaluation of the Trust's crude oil and natural gas reserves at December 31, 2006 were:

Year	Heavy Oil (\$/bbl)	Medium/Light Oil (\$/bbl)	Natural Gas (\$mcf)	NGLs (\$/bbl)
2007	\$ 38.69	\$ 68.23	\$ 7.44	\$ 56.57
2008	39.58	68.14	7.90	56.48
2009	38.09	64.66	7.82	53.74
2010	37.33	62.11	7.81	51.88
2011	36.42	60.30	7.95	50.56
2012	37.82	61.43	8.16	51.66
2013	38.77	62.60	8.32	53.01
2014	39.81	64.70	8.47	54.40
2015	40.78	66.08	8.65	55.66
2016	41.99	67.51	8.81	56.91
2017	43.55	68.76	8.99	58.14
2018	44.98	70.09	9.17	59.40
Remaining	53.81	78.70	10.83	70.88

5. GOODWILL

(\$000s)	Years ended December 31,	
	2006	2005
Balance, beginning of period	\$ 71,970	\$ -
Prairie Schooner acquisition (note 3a)	71,601	-
Shellbridge acquisition (note 3b)	24,017	-
TKE acquisition (note 3c)	2,180	42,393
Meridian acquisition (note 3e)	-	29,577
Goodwill impairment recognized	(169,768)	-
Balance, end of period	\$ -	\$ 71,970

The Trust reviewed the valuation of goodwill as of December 31, 2006 based upon the latest available data. Based upon this review, an impairment of goodwill of \$169.8 million has been recorded as a non-cash charge to income as of December 31, 2006.

6. LONG-TERM DEBT

The Trust has a \$15 million demand operating facility provided by one Canadian bank and \$210 million extendible revolving term credit facility syndicated by the Canadian chartered bank, a U.S. bank, a foreign bank and one institutional lender. Amounts borrowed under the credit facility bear interest at a floating rate based on the applicable Canadian prime rate, U.S. base rates, LIBOR rates, plus between 0% and 1.95%, depending on the types of borrowings and the Trust's debt to cash flow ratio. Security is provided by a \$400 million debenture containing a first ranking security interest on all of the Trust's assets. The credit facility is secured against all the assets of True Energy Inc., the Trust and all material subsidiaries. True has provided a negative pledge and undertaking to provide fixed charges over major petroleum and natural gas reserves in certain circumstances. A standby fee is charged on between 0.125% and 0.400% on the undrawn portion of the facility, depending on the Trust's debt to cash flow ratio. The borrowing base is currently scheduled for renewal on or before March 31, 2007. As at December 31, 2006, there was \$4.9 million outstanding under the operating facility and \$153.0 million outstanding under the revolving term credit facility, which leaves approximately \$67.1 million under the facility.

The revolving period on the new revolving term credit facility ends on June 29, 2007, unless extended for a further 364 day period. Should the facilities not be renewed they convert to 366 day non-revolving term facilities on the renewal date. Payment will not be required under the revolving term facility for more than 365 days from the balance sheet date and as at December 31, 2006 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.

7. CONVERTIBLE DEBENTURES

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

The convertible debentures have a face value of \$1,000 per debenture and a maturity date of June 30, 2011. The convertible debentures bear interest at an annual rate of 7.50% payable semi-annually on June 30 and December 31 in each year 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 are amortized over the term of the debentures. The debt component of the convertible debentures will accrete up to the principal balance at maturity. The accretion, amortization of issue costs 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 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

The following table shows the deferred financing charges activities for the year ended December 31, 2006:

Deferred financing charges (\$000s)

Costs incurred	\$ 3,989
Less amortization in the period	(437)
Balance, December 31, 2006	\$ 3,552

8. OBLIGATIONS UNDER CAPITAL LEASE

Leases relating to gas compression and other equipment with initial costs totaling \$1.2 million (2005 - \$1.2 million) million have been classified as capital leases and are included in property, plant and equipment. The remaining capital lease obligation of \$111 thousand has an implicit interest rate consisting of a variable Bankers Acceptance rate + 3.7%; and will be repaid in 2007.

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 \$74.7 million which will be incurred between 2007 and 2053. A credit-adjusted risk-free rate of 8.0 percent and an inflation rate of 2.2 percent were used to calculate the fair value of the asset retirement obligation.

(\$000s)	2006	2005
Asset retirement obligation, beginning of year	\$ 10,457	\$ 3,951
Liabilities acquired through corporate acquisitions	13,704	7,152
Liabilities incurred	1,210	1,717
Changes in prior period estimates	810	(2,381)
Liabilities released on dispositions	(641)	(318)
Accretion expense	1,065	336
Asset retirement obligation, end of year	\$ 26,605	\$ 10,457

10. EXCHANGEABLE SHARES OF SUBSIDIARY

Authorized:

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

	2006		2005	
	Number	Amount (\$000s)	Number	Amount (\$000s)
Balance, beginning of year	788,558	\$ 9,709	-	\$ -
TKE shares acquired under Arrangement	-	-	843,304	10,351
Non-controlling interest expense	-	(803)	-	22
Exchanged for trust units	(385,022)	(4,753)	(54,746)	(664)
Balance, end of year	403,536	\$ 4,153	788,558	\$ 9,709

The Series A exchangeable shares are non-voting (but holders are entitled to equivalent voting rights in the Trust) and can be converted, at the option of the holder into trust units at any time. If the number of exchangeable shares outstanding is less than 180,000, the Trust can elect to redeem the exchangeable shares for trust units or an amount in cash equal to the amount determined by multiplying the exchangeable ratio on the last business day prior to the redemption date by the current market price of a trust unit on the last business day prior to such redemption date. The number of trust units issued upon conversion is based on the exchange ratio in effect on the date of conversion. The exchange ratio is calculated monthly based on the five day weighted average trust unit trading price preceding the monthly effective date. The exchange ratio was adjusted November 2, 2005 to reflect the consolidation of trust units on a 1 for 2 trust unit basis. The exchangeable shares are not eligible for cash distributions; however cash distributions will increase the exchange ratio.

As at December 31, 2006, the exchange ratio was 0.71107 (2005 - 0.57686).

Retraction of Exchangeable Shares

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

Redemption of Exchangeable Shares

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

11. UNITHOLDERS' CAPITAL

a. Trust Units of True Energy Trust

The Trust Indenture provides that an unlimited number of trust units may be authorized and issued. Each trust unit is transferable, carries the right to one vote and represents an equal undivided beneficial interest in any distributions from the Trust and in the net assets of the Trust in the event of termination or winding-up of the Trust. All trust units are of the same class with equal rights and privileges. Trust units are redeemable at any time at the lesser of 90% of the

market price (as determined in accordance with the Trust Indenture) and the closing price of the trust units on the date tendered for redemption to a maximum, unless waived, of \$250,000 per calendar month in which case the redemption price is payable by distributing notes of the Trust's subsidiary or notes of the Trust.

	2006		2005	
	Number	Amount (\$000s)	Number	Amount (\$000s)
Balance, beginning of year	36,176,196	\$ 418,968	-	\$ -
Units issued for True Common Shares	-	-	51,550,302	223,686
TKE units acquired under Arrangement	-	-	20,708,128	196,214
	<u>36,176,196</u>	<u>418,968</u>	<u>72,258,430</u>	<u>419,900</u>
Balance after 1:2 consolidation	36,176,196	418,968	36,129,215	419,900
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	231,035	4,753	30,869	664
Units issued pursuant to DRIP	3,574,185	42,608	16,112	301
Issued to acquire property interest	145,358	1,817	-	-
Unit issue costs, (net of \$0.4 million tax)	-	-	-	(1,897)
Balance, end of year	70,275,703	\$ 876,904	36,176,196	\$ 418,968

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 year ended and as at December 31, 2006.

Unit Rights Continuity

	Average Exercise Price ^(a)	Number
Balance, December 31, 2004	\$ -	-
Granted	\$ 18.27	3,159,000
Forfeited	\$ -	-
Balance, December 31, 2005	\$ 17.94	3,159,000
Granted	\$ 12.67	3,022,500
Forfeited	\$ 14.66	(751,669)
Balance, December 31, 2006	\$ 14.18	5,429,831

Unit Rights Outstanding

Exercise Price Before Price Reductions	Exercise Price Net of Reductions	At Dec. 31, 2006	Outstanding Exercise Price Net of Price Reductions ^(b)	Remaining Contractual Life ^(b)	Exercisable	
					At Dec. 31, 2006	Exercise Price Net of Price Reductions ^(b)
\$10.58 - \$12.53	\$10.15 - \$12.00	1,539,000	\$ 10.40	4.7	-	N/A
\$13.74 - \$14.83	\$12.63 - \$13.80	681,000	\$ 13.05	4.5	-	N/A
\$15.92 - \$16.70	\$14.41 - \$15.16	227,500	\$ 14.61	4.3	29,166	14.93
\$18.25 - \$20.98	\$16.15 - \$19.10	2,982,331	\$ 16.36	3.9	1,919,888	16.27
\$10.58 - \$20.98	\$10.30 - \$19.10	5,429,831	\$ 14.18	4.2	1,949,054	16.25

^(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 first three months of the plan ended December 31, 2006, the Trust matched \$0.1 million under the plan.

d. Common Shares of True Energy Inc.

Authorized:

Unlimited number of voting Common shares

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

Issued:

	Number of Shares	Amount (\$000s)
Balance, December 31, 2004	62,097,979	\$ 60,229
Options exercised	5,252,694	11,397
Issued on acquisition of Meridian Energy Corporation	35,749,931	150,150
Share issue costs (net of future income taxes of \$0.4 million)	-	(671)
Tax effect of 2004 flow-through shares	-	(2,115)
Transfer from contributed surplus to share capital on exercise of options	-	4,696
Balance prior to Plan of Arrangement	103,100,604	223,686
Balance after 2:1 consolidation	51,550,302	223,686
Exchanged for Trust units	(51,550,302)	(223,686)
Balance, December 31, 2005	-	\$ -

e. Stock Options of True Energy Inc.

The following table summarizes the changes in stock options outstanding for the year ended December 31, 2005.

	Options	Weighted-Average Exercise Price
Outstanding, December 31, 2004	3,958,567	\$ 1.35
Cancelled	(417,873)	1.95
Granted	1,712,000	4.01
Exercised	(5,252,694)	2.17
Outstanding, December 31, 2005	-	\$ -

12. CONTRIBUTED SURPLUS

(\$000s)	Year ended December 31	
	2006	2005
Balance, beginning of year	\$ 5,127	\$ 877
Unit-based compensation expense	7,691	5,127
Stock-based compensation expense	-	3,819
Transfer to share capital on exercise of options	-	(4,696)
Balance, end of year	\$12,818	\$ 5,127

a. Unit-based Compensation

During 2006, the Trust granted 3,022,500 unit incentive rights to employees and directors. In 2006 the Trust recorded unit-based compensation of \$7.7 million, of which \$1.1 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 year ended December 31, 2006 and the assumptions used in their determination are as noted below.

	Year ended December 31, 2006
Assumptions:	
Risk free interest rate (%)	4
Expected life (years)	5
Expected volatility (%)	24
Results:	
Weighted average fair value of incentive rights granted	\$ 4.27

b. Stock-based Compensation

The expense recognized applies to stock options granted in 2003 and thereafter. During the year ended December 31, 2006, the Trust granted nil (2005: 1,712,000) stock options to employees, consultants, officers and directors.

For stock options granted in 2002 and prior years, the Trust elected to continue accounting for the related compensation expense on the intrinsic value at the grant date. Accordingly, net income for 2002 and subsequent years remains unchanged with respect to stock options granted in 2002.

The Trust continues to disclose the pro forma earnings impact of stock options granted in 2002. If the fair value method had been used for options granted in 2002, the Trust's net earnings and net earnings per share for the years ended December 31, 2005 would approximate the following pro forma amounts:

	Year ended December 31, 2005
<i>(\$000s, except per trust unit amounts)</i>	
Net Earnings:	
As reported	\$ 13,890
Pro forma	\$ 13,865
Net Earnings per trust unit:	
As reported	\$ 0.56
Pro forma	\$ 0.56
Diluted:	
As reported	\$ 0.55
Pro forma	\$ 0.55

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions and resulting values for grants as follows:

	Year ended December 31, 2005
Assumptions:	
Risk free interest rate (%)	2.80
Expected life (years)	5.0
Expected volatility (%)	44
Results:	
Weighted average fair value of options granted	\$ 1.69

13. SUPPLEMENTAL CASH FLOW INFORMATION

Cash Interest and Taxes Paid

(\$000s)	Year ended December 31,	
	2006	2005
Cash paid:		
Interest	\$ 10,598	\$ 1,308
Taxes (net of refunds)	\$ 4,476	\$ 1,659

Change in Non-cash Working Capital

(\$000s)	Year ended December 31,	
	2006	2005
Changes in non-cash working capital items:		
Accounts receivable	\$ 25,633	\$ (18,671)
Deposits and prepaid expenses	(4,887)	(154)
Accounts payable and accrued liabilities	(37,449)	34,179
Capital taxes	(1,634)	336
	\$ (18,337)	\$ 15,690
Changes related to operating activities	\$ 36,925	\$ 21,665
Changes related to financing activities	143	(10,664)
Changes related to investing activities	(55,405)	4,689
	\$ (18,337)	\$ 15,690

In December 2006, the Trust closed on an asset exchange agreement whereby certain property interests of the Trust in Saskatchewan were exchanged for other property interests in Saskatchewan from another oil and gas producer. The exchange was a non-cash transaction that was valued at approximately \$8.4 million as agreed by the parties.

14. INCOME TAXES

The Trust is a mutual fund trust as defined under the Income Tax Act (Canada). All taxable income earned by the Trust has been allocated to unitholders and such allocations are deducted for income tax purposes. The Trust does not recognize any future income tax assets or liabilities on "temporary differences" (difference between the accounting basis and tax basis of assets and liabilities) in the Trust. As at December 31, 2006, this "temporary difference" (tax basis exceeds accounting basis) is \$7.1 million (2005: \$4.1 million). The Trust's subsidiaries are subject to income taxation and provide income tax obligations based upon statutory corporate rates.

As at December 31, 2006, the Trust's subsidiaries have tax basis of approximately \$478 million that is available to shelter future taxable income. Included in this tax basis are estimated non-capital loss carry forwards of approximately \$5.6 million that expire in years through 2026. In addition, the Trust has approximately \$20 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 35.7% (2005: 39.5%) to earnings before income taxes. This difference results from the following items:

(\$000s)	Year ended December 31,	
	2006	2005
Expected income tax expense (recovery)	\$ (118,645)	\$ 7,878
Amount in Trust income	(33,757)	(7,090)
Goodwill impairment	60,620	-
Crown royalties and charges	5,032	5,044
Resource allowance	(4,292)	(4,836)
Unit based compensation expense	2,356	3,533
Change in enacted tax rates	(11,548)	(1,507)
Other	(911)	(379)
Total tax expense (recovery)	(101,145)	2,643
Future income tax expense (recovery)	(101,145)	2,636
Current income tax	-	7
Total income tax expense (recovery)	(101,145)	2,643
Capital tax expense	3,245	3,394
Total tax expense (recovery)	\$ (97,900)	\$ 6,037

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

(\$000s)	2006	2005
Future income tax liabilities:		
Petroleum and natural gas properties	\$ (120,203)	\$ (132,899)
Partnership deferrals	(16,374)	(28,354)
Other	(565)	(565)
Future income tax assets:		
Future site restoration/asset retirement obligation	7,899	3,712
Share issue costs	2,207	2,166
Non-capital losses	1,856	8,595
Attributed Canadian Royalty Income	1,209	523
Other	110	93
Net future income tax liability	\$ (123,861)	\$ (146,729)

15. PER TRUST UNIT AMOUNTS

	Years ended December 31,	
	2006	2005
Basic trust units outstanding	70,275,703	36,176,196
Dilutive effect of:		
Trust unit incentive rights outstanding	5,429,831	3,159,000
Units issuable for exchangeable shares	286,942	454,887
Units issuable for convertible debentures	5,390,625	-
Diluted trust units outstanding	81,383,101	39,790,083
Weighted average trust units outstanding	47,217,258	24,678,198
Dilutive effect of exchangeable shares, trust unit incentive plan and convertible debentures (1)	-	454,887
Diluted weighted average trust units outstanding	47,217,258	25,133,085

⁽¹⁾ A total of 286,942 (2005: nil) exchangeable shares, 5,429,831 (2005: 3,159,000) trust incentive units and 5,390,625 (2005: nil) trust units issuable pursuant to the conversion of convertible debentures were excluded from the calculation for the year ended December 31, 2006 as they were not dilutive.

16. RELATED PARTY TRANSACTIONS

During the year ended December 31, 2006, the Trust paid \$1.2 million (2005: \$1.1 million) for legal services provided by a firm in which a current director is a partner. These payments were made in the normal course of operations, on commercial terms, and therefore were recorded at the exchange amount.

17. COMMITMENTS

As at December 31, 2006, the Trust has committed to drill 13 wells in Alberta and 16 wells in Saskatchewan by the end of 2007 pursuant to various farm-in agreements with oil and gas companies. Subsequent to year-end 2006, the Trust has further committed to drill an additional 13 wells in Alberta and 5 in Saskatchewan. Total estimated cost to the Trust for these commitments is \$30.2 million.

The Trust has further committed to various corporate sponsorships extending to June 2010 at an estimated combined cost of up to \$172,000.

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

(\$000s) Year	Gross Amount	Expected Recoveries	Net amount
2007	\$ 1,669	\$ 271	\$ 1,398
2008	1,390	285	1,105
2009	1,000	285	715
2010	285	285	-
2011	285	285	-

18. FINANCIAL INSTRUMENTS

a. Credit Risk

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

b. Fair Value of Financial Instruments

The carrying amounts of financial instruments included in the balance sheet, other than long-term debt, approximate their fair value due to their short-term maturity. The long-term carrying value approximates fair value due to the cost of borrowing being at a floating rate.

c. Interest Rate Risk

The Trust is exposed to interest rate risk to the extent that changes in market interest rates will impact True's bank debt that has a floating interest rate. The trust's convertible debentures have a fixed coupon interest rate of 7.5%. The Trust had no interest rate swaps or hedges at December 31, 2006.

d. Commodity Risk

The Trust seeks to reduce its exposure to commodity price risk in its business through the use of physical product arrangements, futures, and options.

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

Type	Period	Volume	Price		
			Price Floor	Ceiling	Index
Oil put option	Jan. 1, 2007 to June 30, 2007	1,000 bbl/d	\$ 70.00 US	-	WTI
Oil put option	Jan. 1, 2007 to March 31, 2007	800 bbl/d	\$ 70.00 US	-	WTI
Oil put option	April 1, 2007 to June 30, 2007	1,200 bbl/d	\$ 60.00 US	-	WTI
Natural Gas put option	Sept. 1, 2006 to March 31, 2007	10,000 GJ/day	\$ 8.00 CDN	-	AECO C
Natural Gas put option	Nov. 1, 2006 to March 31, 2007	3,000 GJ/day	\$ 8.00 CDN	-	AECO C
Natural Gas collar	Nov. 1, 2006 to March 31, 2007	3,000 GJ/day	\$ 8.50 CDN	\$ 10.50 CDN	AECO C
Natural Gas collar	Nov. 1, 2006 to March 31, 2007	2,000 GJ/day	\$ 9.00 CDN	\$ 10.95 CDN	AECO C
Natural Gas collar	Nov. 1, 2006 to March 31, 2007	3,000 GJ/day	\$ 8.50 CDN	\$ 10.75 CDN	AECO C
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 ⁽¹⁾	April 1, 2007 to Oct. 31, 2007	5,000 GJ/day	\$ 7.00 CDN	\$ 8.76 CDN	AECO C
Natural Gas collar ⁽¹⁾	April 1, 2007 to Oct. 31, 2007	5,000 GJ/day	\$ 7.00 CDN	\$ 8.12 CDN	AECO C
Natural Gas fixed	Nov. 1, 2006 to March 31, 2007	2,000 GJ/day	\$ 9.32 CDN	\$ 9.32 CDN	AECO C
Natural Gas fixed	Nov. 1, 2006 to March 31, 2007	3,000 GJ/day	\$ 9.48 CDN	\$ 9.48 CDN	AECO C
Natural Gas fixed ⁽¹⁾	April 1, 2007 to Dec. 31, 2007	5,000 GJ/day	\$ 7.00 CDN	\$ 7.00 CDN	AECO C
Natural Gas fixed ⁽¹⁾	April 1, 2007 to Oct. 31, 2007	5,000 GJ/day	\$ 7.10 CDN	\$ 7.10 CDN	AECO C

⁽¹⁾ These contracts were entered into subsequent to December 31, 2006.

The above contracts require monthly settlement and have been designated as hedges in accordance with Accounting Guideline 13. As at December 31, 2006, the unrealized gain on the then outstanding commodity contracts, which changes on a daily basis, was \$8.2 million. Included in revenue for year ended December 31, 2006 are oil and gas net hedging gains of \$2.6 million (2005: \$0.2 million hedging loss) related to the monthly settlement of the commodity contracts in the period.

19. SUBSEQUENT EVENT

On January 15, 2007, the Trust announced its intention to convert into a intermediate exploration and production company (the "Reorganization"). Pursuant to the Reorganization, it is contemplated that holders of True trust units ("Trust Units") will receive an equal number of shares of a newly formed corporation that will hold the assets previously held directly or indirectly by the Trust. The exchangeable shares will also be exchanged for common shares based on the conversion ratio thereof. The Reorganization will be 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.

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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