

PRESS RELEASE
TRUE ENERGY ANNOUNCES 2003 YEAR-END FINANCIAL RESULTS

For Immediate Release

March 11, 2004 – True Energy Inc. (“True”) (TSX: TUI) is pleased to announce its financial results for the three and twelve months ended December 31, 2003 as well as a brief operational update of activities during the first quarter of 2004.

Subsequent to the end of 2003, True has drilled 22 (15.2 net) wells of its 2004 drilling program, at a net 84% success rate to-date. Current production is approximately 4,600 boe/d based on field estimates. The Company purchased certain petroleum and natural gas assets located in the Company’s West Central Saskatchewan core area. Estimated capital expenditures for the quarter are \$15.5 million.

FINANCIAL AND OPERATING HIGHLIGHTS

	Three months ended Dec. 31		Twelve months ended Dec. 31	
	2003	2002	2003	2002
FINANCIAL (\$ except per share amounts)				
Revenue	10,318,162	5,807,081	37,560,432	18,974,327
Funds flow from operations*	4,308,178	2,632,620	15,807,526	6,088,361
per share - basic	\$0.08	\$0.06	\$0.33	\$0.17
per share - diluted	\$0.08	\$0.06	\$0.32	\$0.17
Cash flow from operations	4,308,178	2,632,620	15,807,526	5,911,661
per share - basic	\$0.08	\$0.06	\$0.33	\$0.16
per share – diluted	\$0.08	\$0.06	\$0.32	\$0.16
Net earnings / loss	(781,877)	698,887	4,328,751	221,663
per share – basic	(\$0.01)	\$0.02	\$0.09	\$0.01
per share - diluted	(\$0.01)	\$0.02	\$0.09	\$0.01
Capital expenditures, net	7,528,692	2,667,098	20,039,875	18,802,290
Debt, net of working capital			14,460,532	19,892,545
Total assets			63,060,147	49,089,596
Shareholders' equity			31,732,229	19,127,701
Shares outstanding				
Basic			54,044,420	45,134,421
Diluted			57,730,420	47,663,587
Weighted average shares				
Basic	54,043,695	45,121,198	48,335,571	36,505,356
Diluted	55,271,364	45,283,731	49,285,718	36,560,469

* funds flow from operations includes prepaid gas revenue

OPERATIONAL
Daily Volumes

Oil and NGLs	(bbls/d)	1,598	1,054	1,192	809
Natural gas	(Mcf/d)	12,908	4,527	10,869	7,396
Total BOE/d	(6:1)	3,749	1,808	3,003	2,042

Prices

Oil and NGLs	(\$/bbl)	23.08	27.31	26.93	27.36
Natural gas – before hedge	(\$/Mcf)	5.76	7.59	6.53	3.96
Natural gas – after hedge	(\$/Mcf)	5.83	7.59	6.51	4.05

Statistics

Operating netback	(\$/boe)	15.53	21.56	18.15	12.60
Operating expenses	(\$/boe)	6.81	8.86	7.44	6.87
General & administrative	(\$/boe)	2.32	3.04	2.47	2.86
Royalties as a % of sales		26%	13%	25%	24%

FINANCIAL REVIEW

The following financial review of the financial results as provided by the management of True Energy Inc. ("True" or "The Company") should be read in conjunction with the audited consolidated financial statements and notes for the three and twelve months ended December 31, 2003 and 2002. Where amounts are expressed on a barrel of oil equivalent basis (BOE), gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel.

This financial review contains the term cash flow from operations, which should not be considered an alternative to, or more meaningful than cash flow from operations as determined in accordance with Canadian generally accepted accounting principals ("GAAP") as an indicator of the Company's performance. The Company presents cash flow from operations per share whereby per share amounts are calculated consistent with the calculation of earnings per share. The consolidated statements of cash flows in the audited consolidated financial statements present the reconciliation between net earnings and cash flow from operations.

Net Earnings and Cash Flow from Operations

True generated cash flow from operations of \$15.8 million for the twelve months ended December 31, 2003, up 167% from the \$5.9 million produced in the same period of 2002. For the three months ended December 31, 2003, cash flow from operations of \$4.3 million grew 64% compared to \$2.6 million for the fourth quarter of the prior year.

Cash Flow From Operations

	Three Months ended Dec. 31,		Twelve Months ended Dec. 31,	
	2003	2002	2003	2002
Cash flow from operations	\$ 4,308,178	\$ 2,632,620	\$ 15,807,526	\$ 5,911,661
Basic	\$ 0.08	\$ 0.06	\$ 0.33	\$ 0.16
Diluted	\$ 0.08	\$ 0.06	\$ 0.32	\$ 0.16

For the year ended December 31, 2003, net earnings were \$4.3 million, compared to \$0.2 million for the same period in 2002. The net loss for the fourth quarter of 2003 was \$0.8 million, compared to net earnings of \$0.7 million in the fourth quarter of 2002.

Net Earnings

	Three Months ended Dec. 31,		Twelve Months ended Dec. 31,	
	2003	2002	2003	2002
Net Earnings / Loss	\$ (781,877)	\$ 698,887	\$ 4,328,751	\$ 221,663
Basic	\$ (0.01)	\$ 0.02	\$ 0.09	\$ 0.01
Diluted	\$ (0.01)	\$ 0.02	\$ 0.09	\$ 0.01

Sales Volumes

Sales volumes for the three months ended December 31, 2003 increased to 3,749 boe/d, up from the 3,303 boe/d reported during the third quarter of 2003, and from the 2,376 boe/d reported for the second quarter of 2003. During the fourth quarter of 2003 the Company more than replaced production declines as a result of drilling successes, achieving exit production rates of 4,140 boe/d, weighted approximately 60% towards natural gas, by the end of December.

		Three Months ended Dec. 31,		Twelve Months ended Dec. 31,	
		2003	2002	2003	2002
Natural gas	(Mcf/d)	12,908	4,527	10,869	7,396
Heavy oil	(Bbls/d)	1,329	878	964	656
Light oil & NGLs	(Bbls/d)	269	176	228	153
Total crude oil & NGLs	(Bbls/d)	1,598	1,054	1,192	809
Total BOE/d	(6:1)	3,749	1,808	3,003	2,042

Average sales volumes on a year over year basis in 2003 have grown by 47% compared to 2002. Fourth quarter rates have grown by 107%. In the fourth quarter of 2002, an adjustment to production volumes of

811 boe/d was made to adjust for the effect of a payout, reducing volumes for the fiscal year by 205 boe/d.

For the three-month and twelve-month periods, sales volumes for all three commodities were higher. During the fourth quarter, weighting towards natural gas was 57% compared to 42% in the corresponding 2002 period.

Sales of natural gas averaged 12.9 Mmcf/d during the fourth quarter, to exit 2003 at 14.9 Mmcf/d with the completion of a fourth Saskatchewan gas processing facility at Coleville South, additional compression at Smiley and as a result of successful drilling in the Coleville South, Coleville Driver, Dodsland, Smiley, Donalds, and Goodwin areas. At year end, the Company had natural gas wells in the Dodsland/Druid area awaiting tie-in during the first quarter of 2004.

Oil and NGL sales volumes grew 360 bbls/d during the fourth quarter of 2003 with the successful drilling of two horizontal heavy oil wells at Kerrobert to average 1,598 bbls/d. During 2003, True drilled 10 successful light oil wells at Kerrobert accounting for the increased sales of light oil and NGL's during the year. Average sales during the last quarter of 2002 were 1,054 bbls/d.

Commodity Prices

Average Prices

		Three Months ended Dec. 31,		Twelve Months ended Dec. 31,	
		2003	2002	2003	2002
Natural gas – before hedge	(\$/ Mcf)	5.76	7.59	6.53	3.96
Natural gas – after hedge	(\$/ Mcf)	5.83	7.59	6.51	4.05
Heavy crude oil	(\$/ bbl)	19.97	25.31	23.92	25.38
Light crude oil & NGL's	(\$/ bbl)	38.48	37.25	39.68	35.84
Crude oil & NGL's	(\$/ bbl)	23.08	27.31	26.93	27.36
Total	(\$/ boe)	29.92	34.91	34.27	25.46

NYMEX prices during 2003 were 63% higher than in 2002. Partially offsetting this, the US\$/C\$ exchange rate moved from an average of 0.6371 in 2002 to 0.7164 in 2003. The effect of these changes produced an average Alberta Spot price of \$6.50/mcf in 2003, 64% higher than 2002's average price of C\$3.96/mcf. Similarly, before hedges, True received \$6.53/Mcf for its natural gas during 2003, up 65% from the average of \$3.96/Mcf received in 2002. True's natural gas is primarily sold on the daily spot market.

For the three months ended December 31, 2003, before accounting for hedges, True's natural gas averaged \$5.76/Mcf, 1% greater than the Alberta Spot price of \$5.69/Mcf. The fourth quarter of 2002 included the impact of payout adjustments over a twenty four month period, making the net price not reflective of operations for this period alone.

During 2003, WTI averaged US\$31.10/bbl, up 19% from the average US\$26.13/bbl in 2002. Exchange rates deteriorated over the same period from 0.6371 in 2002 to an average of 0.7164 in 2003. The combination of these two factors resulted in Edmonton Par prices growing 8% to \$43.39/bbl in 2003, from \$40.20/bbl in 2002. For heavy oil, differentials averaged \$11.01/bbl in 2003 compared to \$8.43/bbl in 2002, producing a net change of 2% in price for Bow River heavy crude to \$32.38/bbl in 2003, compared to \$31.77/bbl in 2002. True's net price is after adjustments for condensate blending and pipeline tariffs, with the price received directly proportional to the cost of condensate blending. In 2002, True's price was approximately 80% of the net Bow River price. In 2003, the average heavy oil price received was \$23.92/bbl, or 74% of the Bow River price, attributed to increased proportional sales from the Kerrobert McLaren field during 2003 and related condensate blending charges.

In the fourth quarter of 2003, the average WTI price was \$31.18/bbl and Edmonton Par was C\$39.85/bbl, or 8% less than in 2002. With the heavy oil differential during this period widening from C\$10.95/bbl in 2002 to \$11.58/bbl during 2003, the net Bow River price in the fourth quarter of 2003 was \$28.27/bbl. True's net heavy oil sales price averaged \$19.97/bbl, 71% of the Bow River price, directly proportional to the impact of changes in condensate blending costs.

The Company believes commodity prices during 2004 will remain strong. In comparison to 2003, True anticipates crude oil prices will strengthen. This conclusion is supported by a number of indicators. OPEC's actions to date indicate a willingness to maintain prices in or above the \$US28.00 range. In the United States, inventories of crude oil are below the five year average. Numerous studies suggest that demand may outstrip supply. Political instability in the Middle East continues.

In comparison to 2003, True anticipates natural gas prices may soften somewhat during 2004, although still remain very healthy. Although current underground storage numbers are slightly below the five year average, in comparison to inventories last year, current levels are solidly ahead. Tempering this is the relatively muted supply response, despite record drilling activity in both Canada and the United States.

Revenue

Revenue for the twelve months ended December 31, 2003 was \$37.6 million, 98% greater than the \$19.0 million generated in the same period in 2002. During the fourth quarter of 2003, revenue was \$10.3 million, up 78% from \$5.8 million for the corresponding three months of the previous year. The higher fourth quarter revenue in 2003 compared to 2002 was the result of growth in production volumes for both natural gas and crude oil & NGL's partially offset by lower commodity prices.

Revenue (\$000s)

	Three Months ended Dec. 31,		Twelve Months ended Dec. 31,	
	2003	2002	2003	2002
Crude oil & NGLs	3,392	2,648	11,715	8,083
Natural gas	6,845	3,159	25,903	10,636
Natural gas hedge	81	-	(58)	255
Total	10,318	5,807	37,560	18,974

Hedging

True had a natural gas commodity price swap for 3,000 gigajoules per day for the period April 1, 2003 to October 31, 2003 based on an AECO "C" price of Cdn. \$6.08 per gigajoule. For the three months ending December 31, 2003, the Company recorded an increase to gas sales of \$80,669. Over the period of the contract, True incurred a net cost of \$57,861. Currently, the Company has no hedges in place.

Royalties

For the year ending December 31, 2003, total royalties were \$9.5 million, 113% more than the \$4.5 million incurred in the same period in 2002. For the three months ended December 31, 2003, the Company paid \$2.6 million in royalties, 250% more than in the corresponding quarter of 2002. Saskatchewan production brought on-stream after October 1, 2002 was subject to lower royalty rates with the province's budget amendments. Royalties as a percentage of pre-hedge sales for the twelve and three months ending December 31, were 25% and 26% respectively in 2003. Fourth quarter 2002 royalties reflected an impact of a significant adjustment for the conversion of an overriding royalty to a working interest position. On a per unit basis, royalties have increased reflecting the impact of higher commodity price levels. Lower fourth quarter 2002 per unit royalties reflect the impact of the payout.

Royalties, by Commodity Type (\$000's)

	Three Months ended Dec. 31,		Twelve Months ended Dec. 31,	
	2003	2002	2003	2002
Crude oil & NGL's	710	421	2,474	1,677
Natural gas	1,903	325	7,043	2,787
Total	2,613	746	9,517	4,464

Royalties, as a % of Commodity Sales (excluding hedge)

	Three Months ended Dec. 31,		Twelve Months ended Dec. 31,	
	2003	2002	2003	2002
Crude oil & NGL's	21	16	21	21
Natural gas	28	10	27	26
Total	26	13	25	24

Royalties, by Type (\$000s)

	Three Months ended Dec. 31,		Twelve Months ended Dec. 31,	
	2003	2002	2003	2002
Crown royalties	1,625	734	6,228	2,917
Freehold & GORR	971	79	3,495	1,646
Alberta Royalty Tax Credit	17	(67)	(206)	(99)
Total	2,613	746	9,517	4,464

The weighting of royalties to gross sales for crude oil and NGL's during 2003 and 2002 have remained constant at 21%, except for the impact of a payout during the fourth quarter of 2002.

Similarly for natural gas, the pre-hedge royalty rate during 2003 and 2002 was in the 25% to 28% band, except for the fourth quarter of 2002 with the payout impact.

The Company has recorded \$206 thousand of Alberta Royalty Tax Credit ("ARTC") during 2003. During the prior year, True recorded ARTC of \$99 thousand with the acquisition of Alberta properties effective August 1, 2002. During the fourth quarter of 2003, True recorded a negative adjustment of \$38 thousand for a pre-acquisition period ARTC audit.

Operating Expenses

For the year ended December 31, 2003, operating costs totaled \$8.2 million, up 59% from the \$5.1 million recorded in the same period of 2002, reflecting the increased production base. For the three month period ended December 31, 2003 \$2.3 million of operating costs were incurred, an increase of 59% over the \$1.5 million in the same three months in 2002. On a barrel of oil equivalent basis, operating expenses averaged \$7.44 for 2003, compared to \$6.87 for the same period of 2002. Weather was a significant factor in high operating costs during the first half of 2003. True has traditionally had higher operating costs during the winter and spring months compared to the summer months. In 2003, this pattern was more pronounced due to harsher and more extended spring break-up conditions than usual. In contrast to the \$9.04/boe that True recorded during the second quarter of 2003, the Company averaged unit operating costs for the fourth quarter of 2003 of \$6.81/boe, 23% lower than the comparable 2002 period.

In 2004, operating costs for the winter months are expected to correlate directly to the severity of the winter weather. The duration of spring breakup will determine the late winter/ early spring cost levels. Assuming average temperatures and spring breakup, operating costs for 2004 are expected to be in the \$7.00 to \$7.50/boe range.

Production Costs, by Commodity Type \$000s

	Three Months ended Dec. 31,		Twelve Months ended Dec. 31,	
	2003	2002	2003	2002
Crude oil and NGL's	944	848	3,456	2,835
Natural gas	1,405	626	4,695	2,284
Total	2,349	1,474	8,151	5,119

Production Costs per Unit, by Commodity Type

		Three Months ended Dec. 31,		Twelve Months ended Dec. 31,	
		2003	2002	2003	2002
Crude oil & NGL's	(\$/ bbl)	6.42	8.75	7.95	9.60
Natural gas	(\$/ Mcf)	1.18	1.50	1.18	0.85
Total	(\$/ boe)	6.81	8.86	7.44	6.87

Operating costs for natural gas properties during the fourth quarter of 2003 averaged \$1.18/Mcf. The average for 2003 was also \$1.18/Mcf, 39% higher than 2002 average costs, triggered by cold winter weather combined with unusually harsh spring breakup conditions during the second quarter of the year. In the fourth quarter of 2002, operating costs include the payout.

For the Company's crude oil and NGL properties, operating costs for both the three and twelve month periods ended December 31 declined in 2003 in comparison to 2002. During the last quarter of 2003 True's crude oil and NGL operating costs averaged \$6.42/bbl, down \$2.33/bbl from the same period in 2002. For 2003, operating costs of \$7.95/bbl reflect savings of \$1.65/bbl from 2002 levels.

Operating Netbacks

Operating netbacks for natural gas were 64% higher in 2003 compared to 2002, with higher commodity prices partially offset by increased unit royalty and operating costs. For the fourth quarter of 2003, field operating netbacks averaged only 58% of 2002 levels, driven by a 24% decline in gas sales prices.

Field Operating Netbacks *Natural Gas*

<i>\$/Mcf</i>	Three Months ended Dec. 31,		Twelve Months ended Dec. 31,	
	2003	2002	2003	2002
Sales	5.76	7.59	6.53	3.96
Hedge	0.07	-	(0.01)	0.09
Royalties	(1.60)	(0.79)	(1.78)	(1.03)
Production expense	(1.18)	(1.50)	(1.18)	(0.85)
Field operating netback	3.05	5.30	3.56	2.17

Operating netbacks for crude oil and NGL's averaged \$11.83/bbl during the fourth quarter of 2003, \$2.39/bbl less than the \$14.22/bbl received for the same period in 2002, the net effect of lower commodity prices and higher royalties partially offset by decreased operating costs. For the year ended December 31, 2003 operating netbacks improved by \$1.22/boe from 2002 to average \$13.30/bbl. The 10% improvement in netbacks reflected lower commodity prices, flat royalties partially offset by lower operating costs.

*Field Operating Netbacks
Crude Oil & NGL's*

<i>\$/bbl</i>	Three Months ended Dec. 31,		Twelve Months ended Dec. 31,	
	2003	2002	2003	2002
Sales	23.08	27.31	26.93	27.36
Royalties	(4.83)	(4.34)	(5.68)	(5.68)
Production expense	(6.42)	(8.75)	(7.95)	(9.60)
Field operating netback	11.83	14.22	13.30	12.08

Operating netbacks for True improved in 2003 by 44% compared to 2002. During the fourth quarter of 2003, the combination of lower commodity prices and higher royalties partially offset by operating costs produced an average netback of \$15.53/boe.

Corporate Field Operating Netbacks

<i>\$/boe</i>	Three Months ended Dec. 31,		Twelve Months ended Dec. 31,	
	2003	2002	2003	2002
Sales	29.92	34.91	34.27	25.46
Royalties	(7.58)	(4.49)	(8.68)	(5.99)
Production expense	(6.81)	(8.86)	(7.44)	(6.87)
Field operating netback	15.53	21.56	18.15	12.60

General and Administrative

Gross general and administrative costs for 2003 were \$4.7 million compared to \$3.1 million for the same period in 2002, reflecting the personnel requirements to administer an increased production base and create exploration opportunities. During the fourth quarter of 2003 gross costs were \$1.6 million, up from the same 2002 period of \$0.9 million.

These total costs are reduced by charges allocated to the Company's capital and operating projects. Total recoveries of general and administrative costs for the fourth quarter of 2003 and 2002 were each \$0.3 million. For the entire year in 2003, recoveries totaled \$1.1 million compared to \$0.7 million in 2002. In addition, True capitalizes those direct costs incurred by exploration-focused personnel. Salaries and benefits for field personnel are charged to the related projects in which they are involved. During the last quarter of 2003, True capitalized \$0.4 million of the \$0.9 million capitalized during 2003, with severance costs accounting for \$0.3 million of this.

*General and Administrative Costs
\$ 000's*

	Three Months ended Dec. 31,		Twelve Months ended Dec. 31,	
	2003	2002	2003	2002
Gross costs	1,565	928	4,676	3,107
Capitalized	(450)	(103)	(884)	(327)
Recoveries	(315)	(320)	(1,082)	(652)
Net costs	800	505	2,710	2,128
Net costs, per unit (\$/ boe)	2.32	3.04	2.47	2.86

While gross general and administrative costs have increased, so too has the amount the Company capitalizes and recovers from operations. On a per unit of production basis, general and administrative expenses for the last three months of 2003 were \$2.32/boe, 24% lower than costs in the same period in 2002. For the 2003 fiscal year general and administrative costs were 14% less than in 2002 averaging \$2.47/boe. The reduced per unit cost in 2003 compared to 2002 is also directly reflective of the increased production base and the increased operations from which costs have been recovered.

Interest Expense

True recorded \$0.1 million of interest expense for the fourth quarter of 2003 compared to \$0.2 million in the same period of 2002. For fiscal 2003 and 2002 interest costs were \$0.8 million. During the third quarter of 2003 the Company reduced its borrowings through the proceeds of two common share issuances. The Company targets maintaining a maximum annualized net debt to historical cash flow ratio of approximately 1.3 times.

In conjunction with the strengthened balance sheet during 2003, the Company has re-negotiated the cost of borrowing with its lender, a Canadian chartered bank. In 2002 interest was incurred at the bank's prime rate plus 1% to 1½%. Interest is now payable at the lenders' prime rate plus an applicable margin, as outlined in the lending agreement, which is based on the debt to cash flow ratio. For the fourth quarter of 2003 this margin was 3/8%, representing significant savings to the Company.

Interest Costs

\$000s, except where noted

	Three Months ended Dec. 31,		Twelve Months ended Dec. 31,	
	2003	2002	2003	2002
Interest expense	119	247	773	781
Interest (\$/ boe)	0.34	1.48	0.71	1.05
Net debt at period end (\$000)	14,461	19,893	14,461	19,893
Debt to periods cash flow ratio annualized	0.8x	1.9x	0.9x	3.4x

Capital Expenditures

Capital expenditures in 2003 of \$20.0 million were primarily spent on oil and gas exploration and development activities. In comparison, in 2002, the Company spent \$18.8 million, with \$14.6 million incurred on the acquisition of Gresham Resources Inc. For the last quarter of 2003, the Company invested \$7.5 million in oil and gas activities compared to \$2.7 million in the same period of 2002.

Capital Expenditures

\$000s

	Three Months ended Dec. 31,		Twelve Months ended Dec. 31,	
	2003	2002	2003	2002
Lease acquisitions & retention	830	256	2,317	760
Geological & geophysical	481	404	1,050	1,164
Drilling & completion costs	4,588	2,199	12,603	6,071
Facilities & equipment	687	50	2,396	1,426
Exploration & development	6,586	2,909	18,366	9,421
Acquisitions	450	365	632	570
Corporate acquisitions	-	(411)	-	14,585
Head office expenditures	493	239	1,042	604
Total expenditures	7,529	3,102	20,040	25,180
Dispositions	-	(435)	-	(6,378)
Net capital expenditures	7,529	2,667	20,040	18,802

During 2003, True drilled or participated in 45 (29.5 net) wells at a net 91% success rate. In the fourth quarter of 2003, True's net success rate was 75% in 11 (6.8 net) wells.

At January 1, 2004 True had 362,493 gross (218,244 net) of undeveloped land. In comparison, at January 1, 2003 the Company had 153,255 net acres of undeveloped land, an addition of 64,989 net acres.

In the third quarter of 2003, the Company entered into a large area farm-in arrangement in the Whitecourt, Alberta area committing to drill four wells prior to March 15, 2004. During 2003, the Company drilled two wells under the terms of this farm-in, and has drilled the two remaining qualifying wells during the first quarter of 2004.

Subsequent to the end of 2003, True has drilled 22 (15.2 net) wells of its 2004 drilling program, at a net 84% success rate to date. The Company has entered into an agreement with an arm's length third party to purchase certain petroleum and natural gas assets located in the Company's West Central Saskatchewan core area. Closing of the acquisition occurred on March 1, 2004 and the Company will account for this acquisition as a purchase on this date.

Depletion, Depreciation and Site Restoration

Depletion, depreciation and site restoration expense for 2003 totaled \$8.4 million compared to \$5.2 million during 2002. For the three months ended December 31, 2003, depletion, depreciation and future site restoration was \$2.9 million compared to \$1.2 million for the same period of 2002. The depletion and depreciation rate for the fourth quarter of 2003 averaged \$8.35/boe, and \$7.63/boe for the fiscal year.

Depletion, Depreciation and Site Restoration Costs \$000's, except where noted

	Three Months ended Dec. 31,		Twelve Months ended Dec. 31,	
	2003	2002	2003	2002
Depletion	1,866	671	5,037	2,615
Depreciation	894	507	2,939	2,262
Future site restoration	119	69	392	303
Total	2,879	1,247	8,368	5,180
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Per unit (\$/ boe)	8.35	7.50	7.63	6.95

Income Taxes

Capital taxes paid by the Company are in respect of the Federal Large Corporations Tax and the Saskatchewan Capital Tax. For the year ended December 31, 2003 the provision for capital taxes is \$0.8 million. For the three months ended December 31, 2003 the capital tax provision was \$0.3 million. The total long term liability for capital taxes is \$0.8 million as at the end of 2003. Capital tax provision for the year ended December 31, 2002 was \$1.2 million, after adjustments for prior years.

During 2003, True has recorded a current income tax recovery of \$0.2 million reflecting recovery of prior over-estimation of taxes of subsidiary corporations. In 2002, the Company also recorded recovery of prior tax year payments of \$0.1 million.

During 2003, there have been substantively enacted changes to the federal and Alberta income tax rates and to deductions for resource income, reducing the rate on resource income, providing for the deduction of crown royalties and eliminating the resource allowance over a five year period. For True, the expected income tax charge was reduced by the impact of approximately 2.51% drop in tax rates, a change in valuation allowance, more than offset by a partnership deferral, and flow-through share renouncements. For the year ended December 31, 2003, the provision for future income taxes was \$4.35 million, with total tax pools of approximately \$39 million.

Liquidity and Capital Resources

At the end of the year 2002, True had a net debt position of \$19.9 million. By December 31, 2003, True's bank line draw was reduced to \$11.6 million with a working capital deficit excluding bank debt of \$2.9 million, or net debt of \$14.5 million. The reduction in overall net indebtedness is due to cash flow from operations combined with the issuance of 8.5 million shares at \$1.15 per share during the third quarter of 2003. The Company's net debt to historical cash flow ratio at the end of 2003 was 0.9 : 1.0.

Since December 31, 2002, the terms and conditions of the credit facility have been revised numerous times. At the end of 2003 this amount was established at \$20 million. The cost of borrowing was similarly reduced with the transition from prime plus one and a quarter to a price grid basis dependant on the Company's net debt to cash flow ratio on a quarter by quarter basis. Currently the credit facility is subject to an annual review by May 31, 2004. The Company has received a non-binding indicative term

sheet to increase the credit facility to \$27.5 million, subject to final bank credit approval, which is anticipated to be received in the next week.

On July 24, 2003 the Company issued 3.5 million flow-through common shares pursuant to a bought-deal private placement offering at a price of \$1.15 per share for gross proceeds of \$4.0 million. The Corporation is committed to renounce \$4.025 million of Canadian Exploration Expense in 2003 to the subscribers of these shares. The Corporation has until December 31, 2004 to incur the qualifying expenditures. Based on the current forecasts of operations for 2004, the Company is confident this obligation will be met. On September 17, 2003 the Company issued 5.0 million common shares pursuant to a bought-deal private placement offering at a price of \$1.15 per share for gross proceeds of \$5.75 million.

The Company expects to be able to fund its capital expenditure program for 2004 using cash flow from operations and forecasted credit facilities. If cash flows are other than projected, capital expenditure levels will be adjusted to meet the targeted ratio. The Company's practices of continually monitoring spending opportunities in comparison to expected cash flow levels allows for adjustments to the capital program as required.

At December 31, 2003 the Company had 54,044,420 common shares outstanding and 3,686,000 options outstanding at an average exercise price of \$0.91 per share. As at March 1, 2004 total common shares issued and outstanding were 54,676,086 and 3,446,000 options were outstanding at an average price of \$1.00 per share.

TRUE ENERGY INC.
CONSOLIDATED BALANCE SHEETS
at December 31, 2003 and 2002

	December 31, 2003	December 31, 2002
ASSETS		
Current Assets		
Accounts receivable	\$ 9,754,654	\$ 7,699,237
Deposits and prepaid expenses	704,380	853,208
	<u>10,459,034</u>	<u>8,552,445</u>
Property, plant and equipment (note 4)	52,601,113	40,537,151
	<u>\$ 63,060,147</u>	<u>\$ 49,089,596</u>
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	\$ 13,336,706	\$ 11,249,520
Bank debt (note 5)	11,582,860	17,195,471
	<u>24,919,566</u>	<u>28,444,991</u>
Capital taxes payable	835,878	686,430
Future site restoration and abandonment costs	1,222,474	830,474
Future income taxes (note 9)	4,350,000	-
Shareholders' equity		
Share capital (note 7)	46,723,901	38,448,124
Deficit	(14,991,672)	(19,320,423)
	<u>31,732,229</u>	<u>19,127,701</u>
	<u>\$ 63,060,147</u>	<u>\$ 49,089,596</u>

See accompanying notes to consolidated financial statements.

TRUE ENERGY INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND DEFICIT
for the periods ended December 31, 2003 and 2002

	Three months ended Dec. 31,		Twelve months ended Dec 31,	
	2003	2002	2003	2002
REVENUE				
Petroleum and natural gas sales	\$ 10,318,162	\$ 5,807,081	\$ 37,560,432	\$ 18,974,327
Royalties, net of Alberta royalty tax credit	2,612,939	746,219	9,516,983	4,464,490
	7,705,223	5,060,862	28,043,449	14,509,837
EXPENSES				
Production	2,349,361	1,473,621	8,150,955	5,119,012
General and administrative	799,600	505,172	2,710,131	2,128,488
Interest on debt	118,607	247,000	773,454	780,533
Depletion, depreciation and site restoration	2,879,379	1,247,303	8,367,913	5,180,268
	6,146,947	3,473,096	20,002,453	13,208,301
EARNINGS BEFORE TAXES	1,558,276	1,587,766	8,040,996	1,301,536
TAXES				
Current income tax recoveries (note 9)	-	(7,465)	(186,611)	(71,340)
Capital taxes	325,745	896,344	784,448	1,151,213
Future income tax (note 9)	2,014,408	-	3,114,408	-
	2,340,153	888,879	3,712,245	1,079,873
NET EARNINGS / LOSS	(781,877)	698,887	4,328,751	221,663
Deficit, beginning of period	(14,209,795)	(20,019,310)	(19,320,423)	(19,542,086)
Deficit, end of period	\$ (14,991,672)	\$ (19,320,423)	\$ (14,991,672)	\$ (19,320,423)
Net earnings per share (note 10)				
Basic	\$ (0.01)	\$ 0.02	\$ 0.09	\$ 0.01
diluted	\$ (0.01)	\$ 0.02	\$ 0.09	\$ 0.01

See accompanying notes to the consolidated financial statements.

TRUE ENERGY INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
for the periods ended December 31, 2003 and 2002

	Three months ended Dec. 31,		Twelve months ended Dec. 31,	
	2003	2002	2003	2002
Operations				
Net earnings (loss)	\$(781,877)	\$698,887	\$4,328,751	\$221,663
Charges not involving cash:				
Depletion, depreciation and site restoration	2,879,379	1,247,303	8,367,913	5,180,268
Future income tax	2,014,408	-	3,114,408	-
Capital tax	196,268	686,430	(3,546)	686,430
Prepaid contract revenue (note 6)	-	-	-	(176,700)
Cash flow from operations	4,308,178	2,632,620	15,807,526	5,911,661
Change in non-cash working capital	(2,773,019)	(752,264)	(3,358,812)	(2,103,736)
	1,535,159	1,880,356	12,448,714	3,807,925
Financing				
Issuance of common shares (note 7)	2,501	9,999	10,081,567	3,050,299
Share issue costs (note 7)	4,274	(55,394)	(774,727)	(406,065)
Stock option costs (notes 7 and 8)	185,739	-	204,530	-
Increase / (decrease) in bank debt	3,948,145	3,711,742	(5,612,611)	(5,024,198)
	4,140,659	3,666,347	3,898,759	(2,379,964)
Investing				
Additions to capital assets	(6,897,136)	(2,626,651)	(19,408,319)	(9,683,821)
Acquisition of capital assets	(631,556)	(911,103)	(631,556)	(911,103)
Proceeds on sale of capital assets	-	459,931	-	6,377,618
	(7,528,692)	(3,077,823)	(20,039,875)	(4,217,306)
Change in non-cash working capital	1,852,874	(2,468,880)	3,692,402	2,789,345
	(5,675,818)	(5,546,703)	(16,347,473)	(1,427,961)
Change in cash	-	-	-	-
Cash, beginning of period	-	-	-	-
Cash, end of period	\$ -	\$ -	\$ -	\$ -

See accompanying notes to consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Years ended December 31, 2003 and 2002

1. SIGNIFICANT ACCOUNTING POLICIES:

The consolidated financial statements of the Company 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. The amounts recorded for depletion and depreciation, the provision for future site restoration, ceiling test factors such as proved reserves production rates, oil and natural gas prices and future costs are estimated. 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 Company and its subsidiaries. Any reference to "the Company" throughout these consolidated financial statements refers to the Company and its subsidiaries. All inter-entity transactions have been eliminated.

(b) Petroleum and natural gas properties:

The Company follows the full cost method of accounting for petroleum and natural gas operations whereby all costs related to the exploration and the 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.

(c) 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.

The Company applies a ceiling test to capitalized costs to ensure that such costs do not exceed the aggregate of the costs of unproved properties plus future net revenues from production of proved reserves at year end product prices less future administrative, financing, site restoration and income tax expenses.

(d) Joint interests:

Substantially all of the Company's exploration and development activities are conducted jointly with others and, accordingly, the financial statements reflect only the Company's proportionate interest in such activities.

(e) Future site restoration and abandonment costs:

Future site restoration and abandonment costs are based on management's estimates and amortized using the unit-of-production method over the remaining proved reserves. The provision is included in depletion, depreciation and site restoration in the statement of operations.

(f) Prepaid contracts:

Advance payments received under prepaid contracts for oil and gas which is 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.

(g) Flow-through common shares:

Resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share issues are renounced to investors in accordance with income tax legislation. The estimated tax benefits transferred to shareholders are recorded as future income taxes and reduce share capital.

(h) Derivative financial instruments:

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

The derivative financial instruments are initiated within the guidelines of the Company'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 Company believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, as the term and notional amount do not exceed the Company's firm commitment or forecasted transaction, and the underlying basis of the instrument, such as commodity price or foreign exchange rate, matches the Company's exposure.

The Company 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. These derivative contracts, accounted for as hedges, are not recognized on the balance sheet. Realized gains and losses on these contracts are 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.

(i) Stock-based compensation plan:

The Company has one stock-based compensation plan, which is described in note 7 (c). Effective January 1, 2003, compensation expense is recognized for these plans when stock options are issued to employees and extending through the vesting periods of the options. Any consideration paid by employees is credited to share capital.

(j) Revenue recognition:

Revenues from the sale of petroleum and natural gas are recorded when title passes to an external party.

(k) 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.

(l) 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.

2. CHANGE IN ACCOUNTING POLICY:

Stock Based Compensation Plan

In September 2003, the CICA amended Section 3870 “Stock-based compensation and other stock-based payments” to be effective for fiscal years beginning on or after January 1, 2004 with earlier adoption encouraged. In the fourth quarter of 2003, the Company adopted the amended standard which requires the use of the fair value method for valuing stock option grants. Under this method, compensation cost, attributable to share options granted to employees or directors is measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. Upon the exercise of the stock options, consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital. Pursuant to the transition rules, the expense recognized applies to stock options granted on or after January 1, 2003. The impact of the adoption of this amended standard is disclosed in note 8.

3. ACQUISITIONS/DISPOSITIONS:

Effective October 1, 2003, the Company entered into an agreement with an arm’s length third party to purchase certain petroleum and natural gas assets located in central Alberta, specifically in the Goodwin, Greencourt, and Corbett areas (the “Acquisition”). Closing of the acquisition occurred on December 4, 2003 and the Company has accounted for this acquisition as a purchase on this date. The purchase price of \$477,412 was fully allocated to petroleum and natural gas properties and has an equivalent tax basis.

On April 26, 2002 the Company sold certain non-strategic assets in the Milton/Hoosier Areas to an arm’s length third party for net proceeds of \$5.9 million. The proceeds from this disposition were fully allocated to petroleum and natural gas properties and have an equivalent tax basis.

On July 31, 2002, the Company acquired all of the issued and outstanding shares of Gresham Resources Inc. pursuant to the plan of arrangement on the basis of 1.4 common shares of the Company for each outstanding share of Gresham. After giving effect to this transaction, the Company had 45,117,756 common shares issued and outstanding. The acquisition was accounted for using the purchase method and was effective July 31, 2002 being the date the majority of Gresham shares were taken up and exchanged for True shares.

The net assets acquired and consideration given were:

Net assets acquired:

Property, plant and equipment	\$14,762,668
Working capital	1,912,955
Future site restoration and abandonment	(100,890)
Debt	<u>(9,077,736)</u>
	<u>\$ 7,496,997</u>

Consideration:

Issued 12,232,654 shares of True Energy valued at \$0.60 per share	\$7,319,313
Acquisition costs	<u>177,684</u>
	<u>\$7,496,997</u>

On October 17, 2002, the Company sold its assets in the North Dodsland Viking Voluntary Unit to an arms length third party for \$424,000. The proceeds from this disposition were fully allocated to petroleum and natural gas properties and have an equivalent tax basis.

4. PROPERTY, PLANT AND EQUIPMENT:

December 31, 2003	Cost	Accumulated depletion and depreciation	Net book value
Petroleum and natural gas properties	\$ 112,499,021	\$ 60,408,569	\$ 52,090,452
Office furniture and equipment	902,817	392,156	510,661
	<u>\$ 113,401,838</u>	<u>\$ 60,800,725</u>	<u>\$ 52,601,113</u>
December 31, 2002			
Petroleum and natural gas properties	\$ 92,616,603	\$ 52,530,569	\$ 40,086,034
Office furniture and equipment	745,360	294,243	451,117
	<u>\$ 93,361,963</u>	<u>\$ 52,824,812</u>	<u>\$ 40,537,151</u>

At December 31, 2003, the estimated future site restoration costs to be accrued over the remaining proved reserves are \$1,886,000 (2002 - \$2,022,000) of which \$392,000 has been recorded as additional depletion and depreciation during 2003 (2002 - \$303,000).

Unproved properties with a cost of approximately \$11,294,000 (2002 - \$9,195,000) included in property, plant and equipment have not been subject to depletion.

At December 31, 2003, the Company performed the ceiling test, using year end prices, and no write-down of the carrying value of the assets is required.

5. BANK DEBT:

The Company has a demand revolving credit facility with an authorized borrowing amount of \$20,000,000 with a Canadian chartered bank. Interest is payable at the lenders' prime rate plus an applicable margin, as outlined in the lending agreement, based on the debt to cash flow ratio. Security is provided by a general assignment of book debts of the Company, a \$10,000,000 floating charge debenture over all assets of the Company, a fixed charge over certain producing petroleum and natural gas reserves at Smiley and first floating charge supplemental debentures of \$80,000,000. A standby fee is charged on one half of one percent on the undrawn portion of the credit facility. The availability under the facility is subject to an interim review by January 31, 2004, and an annual review by May 31, 2004.

6. PREPAID GAS CONTRACT:

The Company entered into a prepaid contract for future delivery of natural gas commencing November 1, 1998. The Company received \$1,387,000 on November 1, 1998 for 1,000 gigajoules of natural gas per day at \$1.90 per gigajoule at the wellhead for a period of two years.

On July 18, 2000, an amending agreement was signed with the consumer which stated that the Company did not have to deliver any gas for the seven months from June 1 to December 31, 2000. The completion of the 458,000 gigajoules of pre-purchase gas delivery restarted at the 1,000 gigajoules per day rate on January 1, 2001. The Company satisfied the remaining obligations under the contract during 2002.

7. CAPITAL STOCK AND CONTRIBUTED SURPLUS:

(a) Authorized:

Unlimited number of voting Common Shares
Unlimited number of non-voting First Preferred Shares

(b) Issued:

	Number of Shares	Amount
Common shares:		
Balance December 31, 2001	28,775,102	\$ 28,484,577
Options exercised	26,665	16,299
Issued through private placement	4,100,000	3,034,000
Issued on acquisition of Gresham Resources Inc.	12,232,654	7,319,313
Share issue costs		(406,065)
Balance December 31, 2002	45,134,421	\$ 38,448,124
Issued on exercise of stock options	409,999	306,567
Issued for cash on private placement	5,000,000	5,750,000
Flow-through shares issued for cash on private placement	3,500,000	4,025,000
Contributed surplus		204,530
Share issue costs, net of future income taxes of \$484,290		(290,438)
Tax effect of flow-through shares		(1,719,882)
Balance December 31, 2003	54,044,420	\$ 46,723,901

The Company has commitments to incur \$2,038,231 of Canadian Exploration Expense deductions in 2004 to satisfy flow-through agreements.

(c) Stock options:

On August 31, 2000, the Board of Directors approved a stock option plan (the "Plan") for directors, officers, employees and consultants of the Company up to a maximum amount as approved by the Shareholders (4,825,000 at December 31, 2003 and 3,050,000 at December 31,

Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercisable Price
\$0.57 to \$0.70	837,500	3.3	\$0.64	425,000	\$0.64
\$0.73 to \$0.79	1,315,000	3.4	\$0.75	787,500	\$0.75
\$0.85 to \$1.00	500,000	3.1	\$0.92	266,666	\$0.90
\$1.15 to \$1.24	359,000	4.2	\$1.22	-	-
\$1.30 to \$1.70	674,500	4.5	\$1.36	-	-
\$0.57 to \$1.70	3,686,000	3.6	\$0.91	1,479,166	\$0.75

2002). The exercise price shall not be lower than the closing sale price for board lots of common shares on the trading day immediately prior to the day on which the options are granted, and an option's maximum term is 5 years. The vesting period is determined by the Board and averages 3 years.

The following table summarizes the changes in stock options outstanding:

	Options	Weighted-Average Exercise Price
Outstanding at December 31, 2001	2,022,500	\$ 0.91
Cancelled	(1,669,169)	0.86
Granted	2,202,500	0.70
Exercised	(26,665)	0.61
Outstanding at December 31, 2002	2,529,166	\$ 0.77
Cancelled	(186,667)	0.73
Granted	1,753,500	1.05
Exercised	(409,999)	0.75
Outstanding at December 31, 2003	3,686,000	\$ 0.91

The following table summarizes information about stock options outstanding at December 31, 2003:

8. STOCK BASED COMPENSATION:

At December 31, 2003, the Company has one stock-based compensation plan, which is described in Note 7(c). In the fourth quarter of 2003, the Company prospectively adopted the amendments to CICA Handbook Section 3870 "Stock-based Compensation and Other Stock-Based Payments" pursuant to the transitional provisions contained therein. In accordance with the transition rules, the expense recognized applies to stock options granted in 2003. During the twelve months ended December 31, 2003, the Company granted 1,753,500 (2002: 2,202,500) stock options to employees, consultants and directors. As a result of adopting this amended standard, net income for the year ended December 31 2003, decreased by \$204,530 and contributed surplus increased by \$204,530.

For stock options granted in 2002 and prior years, the Company 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 Company 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 Company's net earnings and net earnings per share for the years ended December 31, 2003 and 2002 would approximate the following pro forma amounts:

	Three Months ended Dec. 31,		Twelve Months ended Dec. 31,	
	2003	2002	2003	2002
Net Earnings / Loss:				
As reported	\$(781,877)	\$698,887	\$4,328,751	\$221,663
Pro forma	\$(703,311)	\$513,799	\$4,127,773	\$(518,688)
Net Earnings per Share:				
As reported	\$(0.01)	\$0.02	\$0.09	\$0.01
Pro forma	\$(0.01)	\$0.01	\$0.09	\$(0.01)
Diluted:				
As reported	\$(0.01)	\$0.02	\$0.09	\$0.01
Pro forma	\$(0.01)	\$0.01	\$0.08	\$(0.01)

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:

	Three Months ended Dec. 31,		Twelve Months ended Dec. 31,	
	2003	2002	2003	2002
Assumptions:				
Risk free interest rate (%)	5.69	5.34	5.66	5.73
Expected life (years)	5.0	5.0	5.0	5.0
Expected volatility (%)	60	85	85	105
Results:				
Weighted average fair value of options granted (\$)	\$ 0.73	\$ 0.53	\$ 0.52	\$ 0.56

9. INCOME TAXES:

The provision for income taxes differs from the expected amount calculated by applying the combined Federal and Provincial corporate income tax rate (2003: 42.75%, 2002: 44.30%) to earnings or losses before income taxes. This difference results from the following items:

	2003	2002
Expected income tax expense	\$3,437,616	\$576,559
Crown royalties and charges	1,767,302	1,273,618
Resource allowance	(1,654,500)	(1,015,129)
Change in valuation allowance	(916,434)	(17,711)
Change in enacted tax rates	117,884	1,784
Other	362,540	(819,121)
Future income tax expense	\$3,114,408	\$ -
Current Income tax recoveries	(186,611)	(71,340)
Capital tax expense	784,448	1,151,213
Total tax expense	\$3,712,245	\$1,079,873

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

	2003	2002
Future income tax liabilities:		
Petroleum and natural gas properties	\$(2,004,192)	\$ -
Partnership deferral	(5,374,987)	
Future income tax assets:		
Petroleum and natural gas properties	261,795	95,564
Future site restoration	440,420	275,915
Share issue costs	757,500	544,955
Non-capital losses	1,160,946	
ACRI	386,658	
Other	21,860	
	\$(4,350,000)	\$916,434
Valuation allowance		(916,434)
Net future income tax liability	\$(4,350,000)	\$ -

During 2003, a current income tax recovery of \$186,611 was recorded to reflect overestimated income taxes owing by Gresham Resources Inc. and Marengo Exploration Ltd.

During 2002, a current income tax recovery of \$71,340 was recorded to reflect overestimated income taxes owing by Marengo Exploration Ltd. and True Energy Inc.

Included in capital tax expense of \$784,448 are capital taxes of \$835,878 that will become payable in 2004.

10. PER SHARE AMOUNTS:

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year.

The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. Under the treasury stock method, only "in the money" dilutive instruments impact the diluted calculations in computing diluted earnings per share.

In computing diluted earnings and cash flow from operations per share, 950,147 (2002: 55,113) shares were added to the 48,335,571 (2002: 36,505,356) weighted average number of common shares outstanding during the year for the dilutive effect of stock options. A total of 1,021,500 (2002: 1,960,000) options were excluded from the calculation as they were not dilutive.

11. SUPPLEMENTAL CASH FLOW INFORMATION:

	2003	2002
Cash paid:		
Interest	\$ 773,454	\$ 780,533
Taxes (net of refunds)	(152,706)	224,701
Non-cash investing and financing activities:		
Issue of common shares on acquisition of Gresham		7,319,313
Net assets acquired on acquisitions		7,496,997

12. COMMITMENTS:

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

Year	Gross Amount	Expected Recoveries	Net amount
2004	\$654,789	\$177,837	\$476,952
2005	567,404	118,290	449,114
2006	518,153	59,145	459,008
2007	490,388	-	490,388
2008	286,060	-	286,060
	\$2,516,794	\$355,272	\$2,161,522

13. FINANCIAL INSTRUMENTS – COMMODITY RISK:

(a) Credit risk:

A substantial portion of the Company'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 Company sells substantially all of its production to three primary purchasers under normal industry sale and payment terms. Purchasers of the Company'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) Commodity risk:

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

On January 30, 2003, the Company entered into a natural gas commodity price swap for 3,000 gigajoules per day for the period April 1, 2003 to October 31, 2003. The contract establishes that the Company will pay the counter party the differential for any month when the AECO "C" price is established at more than CDN \$6.08 per gigajoule and that the counter party will pay the Company the differential when the AECO "C" price is established at less than CDN \$6.08 per gigajoule. For the year ended December 31, 2003, the Company recorded a reduction to gas sales of \$57,861 for this transaction.

In addition, the Company had entered into a fixed price sales contract to deliver heavy oil Lloydblend (LLK) at a price of \$26.74 per barrel on 100 barrels per day for the period from May 1, 2002 to April 30, 2003. Effective October 1, 2002, the fixed price sales contract was modified in respect of the committed volumes to 50 barrels per day from October 1, 2002 to April 30, 2003. The Company has entered into another fixed price sales contract to deliver heavy oil Lloydblend (LLK) at a price of \$27.87 per barrel on 200 barrels per day for the period January 1, 2003 to June 30, 2003.

During March 2002, the Corporation entered into a natural gas contract for 3,000 gigajoules per day for the period April 1, 2002 to October 31, 2002. The contract established a floor price of Cdn \$4.00 per gigajoule and a ceiling price of Cdn \$5.00 per gigajoule at the AECO-C Hub. The total gain included in 2002 revenue relating to this hedging transaction is \$254,701.

14. SUBSEQUENT EVENTS:

- (a) During the third quarter of 2003, the Company committed to drill four wells pursuant to a farm-in agreement with an oil and gas company in the Whitecourt, Alberta area by March 15, 2004. At December 31, 2003, the Company has drilled two of the four wells and has drilled the remaining two during the first quarter of 2004.

The Company has committed to drill one well pursuant to a farm-in agreement with another oil and gas company in Alberta during 2004.

- (b) Effective January 1, 2004, the Company entered into an agreement with an arm's length third party to purchase certain petroleum and natural gas assets located in the Company's West Central Saskatchewan core area. Closing of the acquisition occurred on March 1, 2004 and the Company will account for this acquisition as a purchase on this date.

READER ADVISORY

In this release, production is stated in barrels of oil equivalent ("BOE") using a six to one conversion basis when converting thousands of cubic feet of natural gas to barrels of oil and a one to one conversion basis for natural gas liquids. Such conversion may be misleading, particularly if used in isolation. A 6:1 conversion ratio is based on energy equivalence between natural gas and oil at the burner tip and does not represent economic equivalence at the wellhead or point of sale.

Statements in this document may contain forward-looking information. The reader is cautioned that assumptions used in the preparation of such information may prove to be incorrect. Events or circumstances may cause actual results to differ materially from those predicted, a result of numerous known and unknown risks, uncertainties, and other factors, many of which are beyond the control of the Company. The reader is cautioned not to place undue reliance on this forward looking information.

True Energy Inc. is a Calgary-based oil and natural gas exploration and development company. The Company's shares trade on The Toronto Stock Exchange under the symbol **TUI**.

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