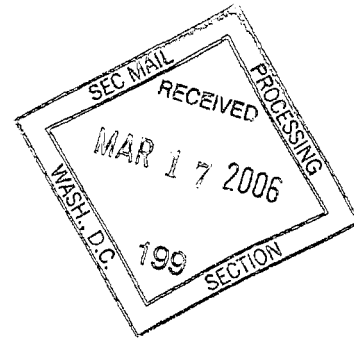


ZARGON
ENERGY TRUST

March 14, 2006



Securities and Exchange Commission
100 F. Street, N.E.
Washington, D.C. 20549
Attention: Filing Desk

Dear Sir or Madame:

Re: Zargon Energy Trust
File No. 82-34907
Exemption Pursuant to Rule 12g3-2(b)

SUPPL

Pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 194, as amended, enclosed is a copy of the Company's news release dated March 14, 2006. As required pursuant to Rule 12g3-2(b), the exemption number appears in the upper right-hand corner of each unbound page and of the first page of each bound document.

Please indicate your receipt of the enclosed by stamping the enclosed copy of this letter and returning it to the sender in the enclosed self-addressed, stamped envelope.

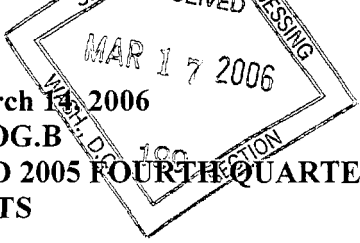
Yours truly,
ZARGON ENERGY TRUST

B.C. Heagy
Vice President Finance & CFO

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MAR 22 2006
THOMSON
FINANCIAL

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Encl.



FOR IMMEDIATE RELEASE: March 14, 2006
TSX SYMBOL: ZAR.UN; ZOG.B
ZARGON ENERGY TRUST ANNOUNCES RECORD 2005 FOURTH QUARTER
AND FULL YEAR RESULTS

Zargon Energy Trust (“Zargon” or the “Trust”) today announced record operating and financial results for the fourth quarter and the year ended December 31, 2005. The year 2005 was the first full year for Zargon operating in a trust format. Zargon Energy Trust was initiated on July 15, 2004 with the acquisition of all of the operational, financial and intellectual assets of its predecessor exploration and production company, Zargon Oil & Gas Ltd.

The reorganization of Zargon Oil & Gas Ltd. into Zargon Energy Trust has been accounted for using the continuity of interest method. Accordingly, all financial and operating information has been reported as if Zargon Energy Trust had always carried on the business of Zargon Oil & Gas Ltd.

Highlights from the fourth quarter and year ended December 31, 2005

- Zargon reported record results for the fourth quarter and the year, primarily driven by historically high commodity prices. Fourth quarter 2005 revenue of \$50.26 million, cash flow from operations of \$26.62 million and net earnings of \$17.45 million were 18 percent, 22 percent and 177 percent respectively higher than the preceding 2005 third quarter levels. Revenue for the full year increased by 31 percent to \$162.72 million, cash flow from operations increased 33 percent to \$84.97 million and net earnings increased 71 percent to \$35.37 million.
- Production in 2005 remained relatively stable with a year-over-year increase of one percent to 8,342 barrels of oil equivalent per day compared to 2004. Fourth quarter production of 27.73 million cubic feet per day of natural gas and 4,030 barrels per day of oil and natural gas liquids provided Zargon record quarterly production volumes of 8,651 barrels of oil equivalent per day and was approximately eight percent higher than third quarter volumes.
- Net capital expenditures in 2005 were \$54.68 million with \$2.42 million of net property and corporate acquisitions and \$52.26 million for exploration and development programs. For the year, Zargon drilled a record 53.5 net wells with a 93 percent success ratio, yielding 35.3 net gas wells, 13.5 net oil wells, 3.8 net dry holes and 0.9 service wells.
- The 2005 capital program replaced 127 percent of Zargon’s 2005 production volumes. Year end proved plus probable reserves increased three percent to 26.77 million barrels of oil equivalent. Including the change in future development costs, Zargon’s 2005 proved plus probable finding, development and acquisition costs were \$14.11 per barrel of oil equivalent. The three-year average proved plus probable finding, development and acquisition costs were \$13.09 per barrel of oil equivalent.
- Cash distributions in 2005 of \$2.32 per trust unit were declared and represented 51 percent of the year’s \$4.51 per trust unit of cash flow from operations. Including the effect of the exchangeable shares, which do not receive distributions, the 2005 cash distributions totalled \$37.44 million or 44 percent of the year’s \$84.97 million of cash flow from operations. Fourth quarter distributions totalled \$1.02 per trust unit and included a December 2005 supplemental distribution of \$0.50 per trust unit.
- Year end net debt (excluding the unrealized risk management liability) of \$27.49 million is less than 0.3 times annualized fourth quarter cash flow.
- On a per unit basis, Zargon’s 2005 production of 445 barrels of oil equivalent per million total trust units was essentially unchanged from the prior year. For the year, Zargon’s proved and probable reserves increased one percent to 1.41 barrels of oil equivalent per total trust unit.

	Three Months Ended December 31,			Year Ended December 31,		
	2005	2004	Percent Change	2005	2004	Percent Change
	(unaudited) (unaudited)					
FINANCIAL HIGHLIGHTS						
Income and Investments (\$ million)						
Petroleum and natural gas revenue	50.26	32.90	53	162.72	123.97	31
Cash flow from operations	26.62	15.36	73	84.97	63.75	33
Cash distributions	16.66	6.43	159	37.44	10.70	250
Net earnings	17.45	5.33	228	35.37	20.63	71
Net capital expenditures	19.12	15.25	25	54.68	56.27	(3)
Per Unit, Diluted						
Cash flow from operations (\$/unit)	1.40	0.82	71	4.51	3.40	33
Net earnings (\$/unit)	1.06	0.34	212	2.19	1.20	83
Cash Distributions (\$/trust unit)	1.02	0.42	143	2.32	0.70	231
Balance Sheet at Year End (\$ million)						
Property and equipment, net				253.32	209.74	21
Bank debt				10.34	14.23	(27)
Unitholders' equity				144.61	120.62	20
Total Units Outstanding at Year End (million)				18.99	18.61	2
OPERATING HIGHLIGHTS						
Average Daily Production						
Oil and liquids (bbl/d)	4,030	3,618	11	3,697	3,416	8
Natural gas (mmcf/d)	27.73	28.93	(4)	27.87	28.84	(3)
Equivalent (boe/d)	8,651	8,440	3	8,342	8,222	1
Equivalent per million total units (boe/d)	457	454	1	445	447	-
Average Selling Price (before risk management gains and losses)						
Oil and liquids (\$/bbl)	57.58	47.13	22	57.15	45.37	26
Natural gas (\$/mcf)	11.34	6.46	76	8.41	6.37	32
Wells Drilled, Net	15.3	16.1	(5)	53.5	49.5	8
Undeveloped Land at Year End (thousand net acres)				367	376	(2)

Notes:

-Total units outstanding include trust units plus exchangeable shares outstanding at period end. The exchangeable shares are converted at the exchange ratio at the end of the period.

-The calculation of barrels of oil equivalent (boe) is based on the conversion ratio that six thousand cubic feet of natural gas is equivalent to one barrel of oil.

-Average daily production per million total trust units is calculated using the weighted average number of units outstanding during the period, plus the weighted average number of exchangeable shares outstanding for the period converted at the average exchange ratio for the period.

-Cash distributions to unitholders commenced subsequent to the reorganization of the Company into a Trust effective July 15, 2004.

-Cash flow from operations is a non-GAAP term that represents net earnings except for non-cash items.

FOURTH QUARTER 2005 CAPITAL PROGRAM

Exploration and development fourth quarter capital expenditures of \$16.82 million were mostly allocated to an active 17 gross (15.3 net) well drilling program that resulted in 12 gross (10.5 net) gas wells, three gross (3.0 net) oil wells and two gross (1.8 net) dry holes. Of the natural gas wells, six were drilled in our Alberta Plains core area and two wells were drilled in each of the Peace River Arch, Pembina and Highvale properties of the West Central Alberta core area. The three oil wells were all drilled in the Williston Basin core area and included two horizontal wells in the Truro and Haas, North Dakota properties.

Zargon experienced very strong results from this expanded fourth quarter exploration and development capital program. The West Central Alberta drilling program provided six higher rate natural gas wells that will be tied-in during the first half of 2006 and will help support trust production levels at current levels throughout the majority of the year. Combined with the active third quarter Williston Basin horizontal drilling program, Zargon added strong wells at Pinto, Saskatchewan and Truro and Haas, North Dakota, that enabled Zargon to increase oil production to 4,030 barrels per day in the fourth quarter, a gain of 13 percent over the prior quarter level.

During the fourth quarter, Zargon also spent \$2.30 million on property and corporate acquisitions that were primarily related to the purchase of a small private company with assets in the Pinto, Saskatchewan area of our Williston Basin core area.

GUIDANCE*

Commencing with the November 2005 distribution, Zargon raised its monthly cash distribution to \$0.18 per trust unit. This distribution is based on Zargon's sustainable trust strategy that calls for the distribution of approximately 50 percent of the Trust's cash flows attributed to the unitholders. At this time, the Trust's distribution levels have been set assuming long term commodity prices of US \$50 per barrel (WTI oil), and US \$8 per mmbtu (NYMEX natural gas). Consistent with last December's supplemental distribution, Zargon will consider further semi-annual supplemental distributions based on the commodity price environment, tax position and funding requirements for Zargon's exploration and development capital program.

In a November 2005 press release reporting third quarter results, the Trust forecast that fourth quarter 2005 production would average 8,500 barrels of oil equivalent per day, comprised of 27.60 million cubic feet per day of natural gas and 3,900 barrels per day of oil and liquids. Actual production for the fourth quarter of 8,651 barrels of oil equivalent per day was two percent higher than guidance with natural gas production of 27.73 million cubic feet per day and a strong oil and liquids production rate of 4,030 barrels per day.

Also in the November 2005 press release, the Trust forecast that 2006 production volumes would average 8,600 barrels of oil equivalent per day, comprised of 27.60 million cubic feet per day of natural gas and 4,000 barrels per day of oil and liquids. At this time, Zargon reconfirms this production guidance which is premised on a 2006 exploration and development capital program of \$45 million. Depending on actual commodity prices and the industry's field cost and activity levels, Zargon's 2006 exploration and development program may be expanded, which could lead to higher production levels. Furthermore, with our very low debt to cash flow ratio, Zargon can make value-added acquisitions when and if they become available using funds from increased bank debt and/or new equity issues.

* Please see comments on "*Forward-Looking Statements*" on the last page of this report.

RESERVES

Formal disclosure of oil and natural gas reserves as required by National Instrument 51-101 Standards of Disclosure ("NI 51-101") will be included in the Trust's Annual Information Form for the year ended December 31, 2005 that will be filed on SEDAR.

Since 1993, the independent engineering firm of McDaniel & Associates Consultants Ltd. ("McDaniel") has evaluated 100 percent of Zargon's reserves. Commencing with the 2003 year end report, Zargon's reserve estimates have been calculated in accordance with National Instrument 51-101 ("NI 51-101"). Under NI 51-101, proved reserve estimates are defined as having a 90 percent probability that actual reserves recovered over time will equal or exceed proved reserve estimates. Probable reserves are defined under NI 51-101 so that there are equal (50 percent) probabilities that the actual reserves to be recovered will be less than, or greater than, the proved and probable reserves estimate.

In a report dated March 13, 2006, McDaniel assigned the following reserve estimates based on forecast prices and costs as of December 31, 2005:

Trust Reserves ⁽¹⁾

At December 31, 2005	Oil and Liquids (mmbbl)	Natural Gas (bcf)	Equivalents ⁽²⁾ (mmboe)
Proved producing	11.30	34.25	17.00
Proved non-producing	0.19	12.27	2.24
Proved undeveloped	-	-	-
Total proved	11.49	46.52	19.24
Probable additional	3.86	21.98	7.53
Total proved and probable	15.35	68.50	26.77
Proved reserve life index, years	7.8	4.6	6.1
Proved and probable reserve life index, years	10.4	6.8	8.5

(1) Trust working interest reserves before royalties, boe (6:1).

(2) Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 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.

In McDaniel's report, proved producing reserves represented 88 percent of Zargon's total proved reserves while total proved reserves accounted for 72 percent of proved plus probable reserves. These percentages are relatively unchanged from the respective 89 and 73 percentages reported in the 2004 year end report. Zargon's proved non-producing reserves are comprised primarily of natural gas reserves from recently drilled wells at the West Central Alberta areas of Pembina, Greater Highvale and the Peace River Arch properties and behind pipe natural gas reserves at the Alberta Plains Jarrow property. Zargon has booked no proved undeveloped reserves as at December 31, 2005. McDaniel forecasts \$6.88 million of net future (forecast prices) capital costs to deliver the total proved reserve estimate. Zargon's probable reserves generally reflect incremental waterflood recoveries on producing oil properties and improved gas recoveries for currently producing natural gas wells. McDaniel forecasts \$8.15 million of net future (forecast prices) capital costs to deliver the total proved and probable reserve estimate.

Based on 2005 year end reserves and Zargon's 2005 fourth quarter production rates of 4,030 barrels of oil and liquids per day and 27.73 million cubic feet of natural gas per day, Zargon's proved reserve life index is 7.8 years for oil and liquids, 4.6 years for natural gas and 6.1 years on an oil equivalent basis. The corresponding proved and probable oil and liquids, natural gas and oil equivalent reserve life indices are 10.4, 6.8 and 8.5 years, respectively. The relatively high oil and liquids reserve life reflects Zargon's portfolio of long-life shallow-decline Williston Basin waterflood projects.

RESERVE RECONCILIATION

A reconciliation of the 2005 year end reserve assignments with the reserves reported in the 2004 year end report is presented below:

Reserve Reconciliation

	Oil and Liquids (mmbbl)			Natural Gas (bcf)			Equivalents (mmboe)		
	Proved	Probable	Proved & Prob.	Proved	Probable	Proved & Prob.	Proved	Probable	Proved & Prob.
December 31, 2004	10.95	3.41	14.36	48.57	20.99	69.56	19.05	6.90	25.95
Discoveries & extensions	0.85	0.48	1.33	8.46	6.12	14.58	2.26	1.50	3.76
Revisions	0.98	(0.04)	0.94	(0.54)	(5.22)	(5.76)	0.89	(0.91)	(0.02)
Acquisitions & dispositions	0.06	0.01	0.07	0.20	0.09	0.29	0.08	0.04	0.12
Production	(1.35)	-	(1.35)	(10.17)	-	(10.17)	(3.04)	-	(3.04)
December 31, 2005	11.49	3.86	15.35	46.52	21.98	68.50	19.24	7.53	26.77

Proved reserves at December 31, 2005 increased one percent from the prior year. Proved 2005 reserve additions were 3.23 million barrels of oil equivalent (after revisions) or 2.34 million barrels of oil equivalent (before revisions). Positive technical reserve revisions were 0.89 million barrels of oil equivalent, which equated to five percent of the 2005 proved reserves opening balance. The majority of the positive revisions were attributed to performance-related adjustments to waterflood oil properties in the Williston Basin offset by negative natural gas revisions due to the watering out of a significant well located at Progress in the Peace River Arch region of the West Central Alberta core area.

On a proved and probable basis, Zargon increased its reserves by three percent in 2005, with the addition of 3.86 million barrels of oil equivalent (after revisions) or 3.88 million barrels of oil equivalent (before revisions), thereby replacing annual production by a factor of 127 percent (128 percent before revisions). Field capital exploration and development programs provided 3.76 million barrels of oil equivalent of new additions, while net acquisitions, primarily in Southeast Saskatchewan, added 0.12 million barrels of oil equivalent additions. Negative technical reserve revisions were 0.02 million barrels of oil equivalent which equated to less than one percent of the 2005 proved and probable reserves opening balance. The majority of the negative technical revisions on a probable basis were due to the watering out of the Progress well. Included in the 2005 capital expenditure program was \$7.12 million for undeveloped land and seismic costs that should provide for future reserves additions in subsequent years.

FINDING, DEVELOPMENT AND ACQUISITION COSTS

For 2005, Zargon's proved and probable finding, development and acquisition costs ("FD&A costs"), taking into account reserve revisions and changes in estimated future development capital during the period, were \$14.11 per barrel of oil equivalent. For the purposes of this calculation, the \$54.68 million of 2005 net capital additions were combined with a decrease in estimated future development capital for proved and probable reserves of \$0.22 million (\$8.15 million at December 31, 2005 compared to \$8.37 million at December 31, 2004). If the change in future development costs is excluded, the 2005 proved and probable finding, development and acquisition costs, taking into account reserve revisions, were \$14.17 per barrel of oil equivalent.

Proved and Probable Finding, Development and Acquisition Costs

	2005	2004	2003
Total net capital expenditures (\$ million)	54.68	56.27	39.91
Total net capital expenditures plus change in forecast future development costs (\$ million)	54.46	57.88	39.00
Proved and probable reserves (mmboe) ⁽¹⁾			
Open	25.95	24.74	23.98
Discoveries & extensions	3.76	2.97	3.71
Acquisitions & dispositions	0.12	0.95	0.77
Revisions	(0.02)	0.30	(1.00)
Production	(3.04)	(3.01)	(2.72)
Close	26.77	25.95	24.74
Proved and probable FD&A costs (\$/boe) ⁽¹⁾	14.11	13.72	11.21
Proved and probable three-year FD&A costs (\$/boe) ⁽¹⁾	13.09	11.89	9.85

(1) Certain comparative numbers reflect the retroactive restatement of removing royalty interest reserves from the Trust interest reserves in accordance with NI 51-101.

Zargon experienced slightly higher FD&A costs in 2005 as the combination of a successful drilling program and positive oil revisions were almost successful in offsetting the negative proved and probable reserve revisions of 4.0 billion cubic feet related to the watering out of a significant West Central Alberta well. Excluding the impact of this write-off, Zargon's 2005 proved and probable FD&A costs would have been a very strong \$12.05/boe.

In 2005, Zargon's net acquisitions (including corporate acquisitions) accounted for only four percent of Zargon's total capital expenditures. If the impact of the 2005 net acquisitions and corporate acquisitions is excluded, Zargon's proved and probable finding and development costs ("F&D costs") would have been \$13.91/boe (2004 – \$14.09/boe).

NET ASSET VALUE

Zargon's oil, natural gas liquids and natural gas reserves were evaluated using McDaniel product price forecasts effective January 1, 2006, prior to provisions for income taxes, interest, debt service charges and general and administrative expenses. It should not be assumed that the following discounted future net property cash flows estimated by McDaniel represent the fair market value of the reserves:

Before Tax Present Value of Future Net Revenue (Forecast Price Case)

(\$ million)	Discount Factor			
	0%	5%	10%	15%
Proved producing	417.9	346.3	298.4	264.6
Proved non-producing	66.3	59.2	53.5	48.8
Proved undeveloped	-	-	-	-
Total proved	484.2	405.5	351.9	313.4
Probable	207.5	135.9	99.5	78.4
Total proved and probable	691.7	541.4	451.4	391.8

**Before Tax Present Value of Future Net Revenue
(Constant Price Case)**

(\$ million)	Discount Factor			
	0%	5%	10%	15%
Proved producing	488.5	391.1	329.2	286.5
Proved non-producing	81.1	70.7	62.7	56.3
Proved undeveloped	-	-	-	-
Total proved	569.6	461.8	391.9	342.8
Probable	248.2	164.2	120.6	94.6
Total proved and probable	817.8	626.0	512.5	437.4

The following net asset value table shows what is customarily referred to as a “produce-out” net asset value calculation under which the current value of Zargon’s reserves would be produced at McDaniel forecast future prices and costs. The value is a snapshot in time as of December 31, 2005 and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. In this analysis, the present value of the proved and probable reserves is calculated at a before tax 10 percent discount rate, and the value assigned to the undeveloped land was provided by the independent firm of Seaton-Jordan & Associates Ltd.

Net Asset Value

As at December 31 (\$ million)	2005	2004	2003
Proved and probable reserves (PVBT 10%) ⁽¹⁾⁽²⁾	451.4	308.2	219.6
Undeveloped land ⁽³⁾	41.7	32.2	29.0
Working capital (excluding unrealized risk management liability)	(17.1)	(9.1)	(6.1)
Bank debt	(10.3)	(14.2)	(7.0)
Proceeds from the exercise of all trust unit rights	20.9	10.3	9.1
Net asset value (including trust unit rights dilution)	486.6	327.4	244.6
Net asset value per unit			
Total (\$/unit)	24.53	17.04	13.09
With full dilution (\$/unit) ⁽⁴⁾	24.45	17.06	12.68

(1) McDaniel’s estimate of future before tax cash flow discounted at PV 10 percent.

(2) PVBT represents present value before taxes.

(3) Seaton-Jordan year end estimates.

(4) Full dilution of units represent the year end units outstanding plus the presumed exercise of all trust unit rights and the conversion of exchangeable shares converted at the exchange ratio at the end of the period.

If the net asset value calculation is adjusted to assume that the commodity prices received at year end 2005 (Edmonton light crude oil at \$68.46 Cdn per barrel and Alberta AECO average natural gas at \$9.29 Cdn per gj) will remain constant throughout the future (McDaniel constant price case), the equivalent analysis calculates a 10 percent present value before tax (PVBT) net asset value of \$27.52 per fully diluted unit.

TRUST SUSTAINABILITY

With the conversion during 2004 to a trust, Zargon’s objectives are to sustain distributions, production and reserves on a per unit basis after paying out approximately 50 percent of cash flow attributable to unitholders.

The following is a summary of the key metrics that Zargon monitors as it works towards meeting its sustainability objectives:

Key Sustainability Metrics

	2005	2004	Percent Change
Annualized cash distributions (\$/unit)	2.32	1.68	38
Cash flow from operations (\$/unit diluted)	4.51	3.40	33
Trust payout ratio (percent)	51	49	4
Production (boe/d per million units)	445	447	-
Proved and probable reserves (boe/total unit)	1.41	1.39	1
Cash flow from operations (\$/boe)	27.91	21.18	32
Proved and probable FD&A costs (\$/boe)	14.11	13.72	3
Trust recycle ratio	1.98	1.54	29
Production addition costs (\$ thousand/boe/d) ⁽¹⁾	35.3	37.6	(6)

(1) The production addition costs for the total capital program are calculated by dividing the year's total capital expenditures by the year's actual change in production rate plus the year's estimated naturally occurring decline in production. This production decline is estimated as the year end proved producing (forecast case) depletion rate (the inverse of the reserve life index) based on fourth quarter production rates.

In early 2006, Zargon reached a significant milestone. Over its thirteen-year history, Zargon has raised approximately \$50 million in equity (includes equity issued for all public and private offerings, for property acquisitions and for the exercise of employee stock options or trust unit rights). With the distribution declared on February 15, 2006, Zargon has paid back this entire amount by distributing \$54 million to its unitholders.

PLAN OF ARRANGEMENT

On July 15, 2004, approval was given by the shareholders to a resolution in favour of a Plan of Arrangement (the "Arrangement") reorganizing Zargon Oil & Gas Ltd. (the "Company") into Zargon Energy Trust (the "Trust" or "Zargon"). The Arrangement received court approval and also became effective on July 15, 2004. The Arrangement resulted in shareholders of the Company receiving either one trust unit or one exchangeable share for each common share held. The unitholders of the Trust are entitled to receive cash distributions paid by the Trust. Holders of exchangeable shares are not eligible to receive distributions, but rather, on each payment of a distribution, the number of trust units into which each exchangeable share is exchangeable is increased on a cumulative basis in respect of the distribution. The exchangeable shares are traded on the Toronto Stock Exchange and can be converted, at the option of the holder, into trust units at any time. On July 15, 2014, all the remaining outstanding exchangeable shares will be redeemed into trust units unless the Board of Directors of the Company elect to extend the redemption period. In certain circumstances, the Company has the right to require redemption of the exchangeable shares prior to July 15, 2014. Upon completion of the Arrangement, 14.87 million trust units and 3.66 million exchangeable shares were issued. The Trust is an unincorporated open-end investment trust governed by the laws of the Province of Alberta. On September 15, 2004, Zargon commenced cash distributions, relating to August 2004, of \$0.14 per trust unit.

The reorganization of the Company into a Trust has been accounted for using the continuity of interest method. Accordingly, the consolidated financial statements for the years ended December 31, 2005 and 2004 reflect the financial position, results of operations and cash flows as if the Trust had always carried on the business of the Company. All comparative figures referred to in the consolidated financial statements and this report are the previous consolidated results of the Company.

Cash Distributions

Cash distributions to unitholders are at the discretion of the Board of Directors and can fluctuate depending on cash flow. The Trust currently targets a payout ratio of approximately 50 percent of the cash flows attributed to unitholders. The Trust's capital program is financed from available cash flow and additional drawdowns on the bank facility if required. The key drivers of Zargon's cash flow are commodity prices and production. Since the Trust's production is relatively evenly weighted between natural gas (2005 – 56 percent) and oil and liquids (2005 – 44 percent), both commodity prices have a significant effect on its cash flow. In the event that oil and natural gas prices are higher than anticipated and a cash surplus develops, the surplus may be used to increase distributions, reduce debt, and/or increase the capital program. In the event that oil and natural gas prices and/or production are lower than expected, the Trust may decrease distributions, increase debt or decrease the capital program. Zargon regularly reviews its distribution policy in the context of the current commodity price environment and production levels.

Distributions remained constant throughout the first seven months of 2005 at \$0.14 per unit per month and had been at that level since the Trust's inception in July 2004. On August 11, 2005, Zargon announced its monthly distribution rate would be increased to \$0.16 per unit, representing a \$0.02 per unit increase. Furthermore, on November 14, 2005 Zargon announced its monthly distribution rate would be increased an additional \$0.02 per unit to \$0.18 per unit. Other than a supplemental distribution (over-and-above the monthly distribution) declared in December 2005 of \$0.50 per unit, distributions have been maintained at the \$0.18 per unit level since that date. Cash distributions to unitholders declared for 2005 totalled \$37.44 million, resulting in a payout ratio for the year of 44 percent of cash flow from operations or 51 percent on a per diluted trust unit basis.

For Canadian income tax purposes, the 2005 cash distributions are 100 percent taxable income to unitholders.

2005 HIGHLIGHTS

The combination of high crude oil prices, natural gas prices, and stable production volumes enabled Zargon to achieve record revenues and cash flow from operations in 2005, showing gains of 31 percent and 33 percent, respectively, over the prior year. The annual revenue gain came from a combination of factors, including a 26 percent increase in oil and liquids prices, an eight percent increase in oil and liquids production, and a 32 percent increase in natural gas prices which more than offset the three percent decline in natural gas production. Net earnings for the year were \$35.37 million, a 71 percent increase from 2004. Earnings for 2005 were primarily enhanced by record cash flows from operations of \$84.97 million, an increase of \$21.22 million from 2004, while 2004 earnings were negatively impacted by a significant one-time charge of \$2.17 million related to the accelerated vesting of stock options as a result of the July 15, 2004 Arrangement.

Net capital expenditures for 2005 totalled \$54.68 million with \$52.26 million allocated to field-related activities. Compared to the prior year, the 2005 capital program showed a three percent decline in overall net expenditures and an 18 percent increase in field-related expenditures. Net property acquisitions of \$1.23 million were lower in 2005 when compared to the 2004 net property acquisitions of \$11.81 million which primarily consisted of a portfolio of oil properties in Weyburn and Elswick, Saskatchewan of the Williston Basin. The 2005 capital expenditures were complemented with the corporate acquisition of a small private Saskatchewan oil and gas company for consideration of \$1.19 million. For the year ended December 31, 2005, Zargon spent \$3.65 million to maintain an undeveloped land base of 367,000 net acres (2004 – 376,000 net acres); shot or acquired seismic at a cost of \$3.47 million; drilled, equipped and tied-in wells for \$45.14 million and made net property acquisitions of \$1.23 million. Cash distributions to unitholders totalled \$37.44 million during the year (2004 – \$10.70 million). All of these activities were funded by the high cash flows received throughout the year plus an increase in debt net of working capital (excluding the unrealized risk management liability) of \$4.12 million.

FINANCIAL HIGHLIGHTS

(\$ million, except per unit amounts)	2005	2004	2003
Petroleum and natural gas revenue	162.72	123.97	101.66
Cash flow from operations	84.97	63.75	54.35
Per unit – diluted	4.51	3.40	2.96
Net earnings ⁽¹⁾	35.37	20.63	24.36
Per unit – diluted ⁽¹⁾	2.19	1.20	1.33
Total assets ⁽¹⁾	277.86	226.96	181.05
Net capital expenditures ⁽²⁾	54.68	56.27	39.91
Bank debt	10.34	14.23	6.98
Cash distributions	37.44	10.70	-

(1) Comparative 2003 period numbers reflect the retroactive restatements due to a change in accounting policy.

(2) Amounts include capital expenditures acquired for cash and equity issuances.

DETAILED FINANCIAL ANALYSIS

Petroleum and Natural Gas Revenue

Zargon derives its revenue from the production and sale of petroleum (oil, natural gas liquids) and natural gas. Petroleum and natural gas revenue, exclusive of risk management losses, increased 31 percent to \$162.72 million in 2005 from \$123.97 million in 2004 primarily due to higher prices and a slight increase in production. Compared to the prior year, the allocation of production revenue in 2005 was essentially unchanged with 47 percent of the revenues coming from the sale of oil and liquids (46 percent in 2004) and 53 percent coming from the sale of natural gas (54 percent in 2004). Production volumes on a barrel of oil equivalent basis in 2005 increased one percent to 8,342 barrels of oil equivalent per day from the prior year amounts of 8,222 barrels of oil equivalent per day. Specifically, in 2005 natural gas production decreased three percent and oil and liquids production increased eight percent over 2004 levels. Production increases in oil and liquids resulted from mid-2004 Williston Basin property acquisitions and field exploitation programs. Natural gas production declines resulted primarily from production losses at a significant well in the West Central Alberta core area in mid-2005. The average price of oil and liquids received by Zargon rose to \$57.15 per barrel in 2005, up 26 percent from 2004. The average field price of natural gas was \$8.41 per thousand cubic feet in 2005, a 32 percent increase over \$6.37 per thousand cubic feet in 2004.

Pricing

Average for the year	2005	2004	2003
Natural Gas:			
NYMEX average daily spot price (\$US/mmbtu)	8.89	5.90	5.49
AECO average daily spot price (\$Cdn/mmbtu)	8.77	6.55	6.70
Realized price (\$Cdn/mcf) ⁽¹⁾	8.41	6.37	6.33
Crude Oil:			
WTI (\$US/bbl)	56.56	41.40	31.04
Edmonton par price (\$Cdn/bbl)	68.72	52.54	43.14
Realized price (\$Cdn/bbl) ⁽¹⁾	57.15	45.37	36.66

(1) Amounts are before risk management losses.

Petroleum (Oil and Natural Gas Liquids) Pricing

Zargon's field oil and natural gas liquids prices are adjusted at the point of sale for transportation charges and oil quality differentials from an Edmonton light sweet crude price that varies with world commodity prices. In 2005, Zargon's average oil and liquids field price, exclusive of risk management losses, rose 26 percent to \$57.15 per barrel from \$45.37 per barrel in 2004 and \$36.66 per barrel in 2003. The field price differential for Zargon's average blended 30 degree API crude stream was \$11.57 per barrel less than the 2005 Edmonton reference crude price, which compares to the 2004 differential of \$7.17 per barrel and the 2003 differential of \$6.48 per barrel. As the quality and weight of Zargon's crude stream have remained relatively consistent for several years, the movements in the Zargon's price differential is derived from the North American refinery supply and demand factors for light and medium crudes.

Natural Gas Pricing

The average field natural gas price, exclusive of risk management losses, for 2005 increased to \$8.41 per thousand cubic feet which is 32 percent higher than the 2004 average of \$6.37 per thousand cubic feet, and also 33 percent higher than the 2003 average of \$6.33 per thousand cubic feet. Historically, Zargon's field prices have shown a small discount to the benchmark AECO average daily price (\$0.36 per thousand cubic feet in 2005), due to a lower heating content for Zargon's natural gas and due to legacy aggregator and other contracts which are partially based on monthly index prices that tend to lag the AECO average daily index price in upward trending markets. Zargon is also committed to various fixed price physical contracts which are treated as part of natural gas production revenue and natural gas pricing. In 2005, the physical contracts created a gain of \$0.18 million (2004 - \$0.25 million), equivalent to an increase of \$0.02 per thousand cubic feet, unchanged from 2004.

Similar to the prior year, approximately 23 percent of Zargon's 2005 natural gas production was sold under aggregator contracts pursuant to long term contracts. The remainder of Zargon's natural gas production was sold by spot sale contracts and Alberta index prices were received.

Risk Management Activities

Zargon's commodity price risk management policy uses forward sales, puts and costless collars for 20 to 35 percent of oil and natural gas working interest production in order to partially offset the effects of large price fluctuations. As both Canadian oil and natural gas field prices are closely correlated to US dollar denominated markets, Zargon will also place US/Cdn currency exchange risk management transactions when considered prudent. Because our risk management strategy is protective in nature and is designed to guard the Trust against extreme effects on cash flow from sudden falls in prices and revenues, upward price spikes tend to produce overall losses. Financial risk management contracts in place as at December 31, 2004, were designated as hedges for accounting purposes and the Trust continues to monitor these contracts in determining the continuation of hedge effectiveness. For these contracts, realized gains and losses are recorded in the statement of earnings as the contracts settle and no unrealized gain or loss is recognized.

For 2005, the total realized risk management loss was \$7.75 million compared to a loss of \$4.57 million in 2004 and a loss of \$2.88 million in 2003. Of the 2005 loss, \$5.17 million (equivalent to a reduction of \$3.83 per barrel) is related to oil risk management transactions and \$2.58 million (equivalent to a reduction of \$0.25 per thousand cubic feet) was related to natural gas risk management transactions. Oil swaps and collars are settled against the NYMEX pricing index, whereas natural gas swaps, collars, and puts are settled against the AECO pricing index. In 2005, NYMEX WTI crude oil prices increased throughout the year, peaking in the month of September. AECO daily natural gas prices also trended upwards during the year and became volatile towards year end. For financial risk management contracts entered into after December 31, 2004, the Trust does consider these contracts to be an effective hedge on an economic basis but has decided not to designate these contracts as hedges for accounting purposes and accordingly, for outstanding contracts not designated as hedges, an unrealized gain or loss is recorded based on the fair value (mark-to-market) of the contracts at the period end. The unrealized losses as at December 31, 2005 were \$3.76 million (2004 – nil). These instruments have been recorded as a liability in the consolidated balance sheet. Gains or losses on fixed price physical contracts are included in petroleum and natural gas revenue in the statement of earnings.

Royalties

Royalties include payments made to the Crown, freehold owners and third parties. Reported royalties also include credits received through the Alberta Royalty Credit (ARC) program, the cost of the Saskatchewan Resource Surcharge (SRC) and the cost of North Dakota state taxes. During 2005, total royalties were \$37.32 million, an increase of 33 percent from \$28.05 million in 2004. Royalties as a percentage of gross revenue were 22.9 percent in 2005 compared to 22.6 percent in 2004 and 22.1 percent in 2003. On a commodity basis, oil royalties averaged 22.5 percent in 2005, a small increase from the previous year's average of 21.5 percent. Natural gas royalties averaged 23.3 percent, relatively unchanged from the prior year.

During 2005, 61 percent of the total royalties were paid to provincial and state governments, with the remainder paid to freehold owners and other third parties. Royalties payable to the Province of Alberta on qualifying properties are reduced through the ARC program. Zargon earned the maximum \$0.50 million ARC rebate in 2005, which is the same amount received in both 2004 and 2003. The SRC charges were \$1.03 million in 2005, up from \$0.64 million in the prior year and \$0.53 million in 2003 trending the increase in Saskatchewan oil revenues. North Dakota state taxes increased to \$1.82 million in 2005 from \$1.25 million in the prior year, primarily due to increased prices for oil, as well as increased production in the state.

Production Expenses

Zargon's production expenses increased 11 percent to \$24.04 million in 2005, from \$21.69 million in 2004. On a unit of production basis, production expenses increased nine percent to \$7.89 per barrel of oil equivalent from \$7.21 in 2004 (\$6.33 in 2003).

Natural gas production expenses in 2005 rose 13 percent to \$0.95 per thousand cubic feet from \$0.84 per thousand cubic feet in 2004. The primary reasons for the increases are due to increased gas gathering charges, increased rentals for compression equipment, increased water disposal and water hauling, all part of the industry-wide trend towards higher operating costs.

Oil production expenses also rose in 2005 to \$10.64 per barrel, an increase of three percent from \$10.30 per barrel in 2004. With the strong oil prices during the year, there is an industry-wide trend to higher operating costs, particularly for chemicals, propane and equipment repairs.

Due to the high levels of industry activity caused by the high commodity price environment, there is increasing upward pressure on per unit operating costs. In 2003, Zargon was able to deliver a cost improvement on a per unit of production basis over the prior year through the disposition of smaller, higher cost properties. In 2005 and 2004, Zargon's costs increased substantially due in general to the effect of industry-wide higher cost trends. For 2006, Zargon expects the trend of increasing costs to persist as the current high demand for industry services is expected to continue.

Operating Netbacks

The average oil and liquids price received after realized risk management losses in 2005 of \$53.32 per barrel was 26 percent higher than the \$42.17 per barrel received in 2004, while the average natural gas price received after realized risk management losses in 2005 of \$8.16 per thousand cubic feet was 29 percent above the \$6.32 per thousand cubic feet received in 2004. Operating netbacks increased commensurately. Oil and natural gas liquids netbacks rose 35 percent to \$29.80 per barrel from \$22.10 per barrel in 2004. Natural gas netbacks increased 32 percent to \$5.25 per thousand cubic feet from \$3.98 per thousand cubic feet in 2004. On a barrel of oil equivalent basis, 2005 operating netbacks rose 33 percent to \$30.75 from \$23.15 in 2004.

OPERATING NETBACKS

	2005		2004	
	Oil and Liquids (\$/bbl)	Natural Gas (\$/mcf)	Oil and Liquids (\$/bbl)	Natural Gas (\$/mcf)
Production revenue	57.15	8.41	45.37	6.37
Realized risk management loss	(3.83)	(0.25)	(3.20)	(0.05)
Royalties	(12.88)	(1.96)	(9.77)	(1.50)
Production costs	(10.64)	(0.95)	(10.30)	(0.84)
Operating netbacks	29.80	5.25	22.10	3.98

General and Administrative Expenses

Gross general and administrative costs increased 24 percent in 2005 to \$8.96 million from \$7.23 million in 2004. On a unit of production basis, net general and administrative costs increased 37 percent to \$1.99 per barrel of oil equivalent, compared to \$1.45 per barrel in 2004 and \$1.30 per barrel in 2003. In 2005, as was the case in 2004, the increased general and administrative costs on a per unit of production basis were due to increased staff costs, performance-based compensation costs, increased regulatory reporting requirements and the additional legal and other outside advisory costs of operating as a trust.

GENERAL AND ADMINISTRATIVE EXPENSES

(\$ million, except as noted)	2005	2004	2003
Gross general and administrative expenses	8.96	7.23	5.94
Overhead recoveries	(2.91)	(2.87)	(2.40)
Net general and administrative expenses	6.05	4.36	3.54
Net expense after recoveries (\$/boe)	1.99	1.45	1.30
Number of office employees at year end	39	35	34

Interest and Financing Charges

Zargon's borrowings are through its syndicated bank credit facility. Interest and financing charges were \$0.79 million compared to \$0.44 million in 2004. An increase in the average debt level is the primary reason for the increase in interest and financing charges. Zargon's effective interest and financing charge rate was 4.3 percent on an average bank debt of \$18.17 million in 2005, compared to 4.9 percent on an average bank debt of \$8.88 million in 2004 and 4.5 percent on an average bank debt of \$17.19 million in 2003. At year end 2005 Zargon's bank debt, net of working capital (excluding unrealized risk management liability), totalled \$27.49 million, up 18 percent from \$23.37 million at December 31, 2004.

Capital and Current Income Taxes

During 2005, Zargon incurred \$1.80 million of current income taxes compared to \$1.11 million in 2004. Of the total, \$0.90 million is due to current taxes incurred in the United States compared to \$0.61 million in 2004. Provided that oil prices remain high, a similar level of United States current income taxes is predicted in 2006. The remaining current tax amounts relate to federal and provincial capital taxes, which were \$0.90 million in 2005 compared to \$0.50 million in 2004. Tax pools as at December 31, 2005 were approximately \$90 million which represents an increase from the comparable \$79 million of tax pools available to Zargon at the end of 2004. The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on the income that is not distributed or declared distributable to unitholders. It is anticipated that sufficient distributions will be made to eliminate current Canadian income tax. For Canadian income tax purposes, 2005 distributions are 100 percent taxable income to unitholders.

Trust Netbacks

Historically high oil prices and the continued strength of natural gas prices in 2005 resulted in higher revenue netbacks and operating netbacks. On a barrel of oil equivalent basis, revenue of \$53.44 in 2005 was 30 percent higher than the prior year and operating netbacks as well as cash flow netbacks increased 33 percent and 32 percent over the prior year to \$30.75 and \$27.91 per barrel of oil equivalent, respectively.

TRUST NETBACKS

(\$/boe)	2005	2004	2003
Petroleum and natural gas revenue	53.44	41.20	37.40
Realized risk management loss	(2.55)	(1.52)	(1.06)
Royalties	(12.25)	(9.32)	(8.28)
Production costs	(7.89)	(7.21)	(6.33)
Operating netbacks	30.75	23.15	21.73
General and administrative	(1.99)	(1.45)	(1.30)
Interest and financing charges	(0.26)	(0.15)	(0.28)
Capital and current income taxes	(0.59)	(0.37)	(0.15)
Cash flow netbacks	27.91	21.18	20.00
Depletion and depreciation ⁽¹⁾	(12.31)	(9.11)	(7.23)
Unrealized risk management loss	(1.24)	-	-
Accretion of asset retirement obligations ⁽¹⁾	(0.39)	(0.36)	(0.43)
Unit-based compensation	(0.30)	(1.22)	(0.10)
Unrealized foreign exchange gain	0.07	0.19	0.11
Future income taxes ⁽¹⁾	(0.16)	(3.20)	(3.38)
Earnings before non-controlling interest ⁽¹⁾	13.58	7.48	8.97

(1) Comparative 2003 period numbers reflect the retroactive restatements due to a change in accounting policy.

Cash Flow from Operations

In 2005, production volumes held steady, but increases of 26 percent in oil and natural gas liquids prices and 32 percent in natural gas prices, produced a 33 percent gain in cash flow from operations to \$84.97 million, compared to \$63.75 million in 2004 and \$54.35 million in 2003. The corresponding cash flow per diluted unit was \$4.51 in 2005, a 33 percent gain from \$3.40 per diluted unit in 2004, and compares to \$2.96 in 2003. The diluted per unit statistics reflected a one percent increase in the weighted average outstanding units to 18.85 million in 2005, and a two percent increase in the average weighted number of outstanding units to 18.72 million in 2004 from 18.37 million in 2003.

The following table summarizes the variances in cash flow from operations between 2004 and 2005. It shows the variance is caused mainly by increased commodity pricing, with partial offset coming from increased royalties and higher realized risk management losses.

	\$ Million	\$ Per Diluted Trust Unit	Per Unit Percent Variance
Cash flow from operations - 2004	63.75	3.40	-
Price variance	36.95	1.97	58
Volume variance	1.81	0.10	3
Realized risk management losses	(3.19)	(0.17)	(5)
Royalties	(9.27)	(0.49)	(14)
Expenses:			
Production	(2.34)	(0.12)	(3)
General and administrative	(1.70)	(0.09)	(3)
Interest and financing charges	(0.35)	(0.02)	(1)
Current taxes	(0.69)	(0.04)	(1)
Weighted average trust units - diluted	-	(0.03)	(1)
Cash flow from operations - 2005	84.97	4.51	33

Depletion and Depreciation

In 2005, Zargon's depletion and depreciation provision increased 37 percent to \$37.48 million, compared to \$27.41 million in 2004 and \$19.66 million in 2003. The higher charges reflect an increase of one percent in production volumes and a 35 percent increase in the charge on a per barrel of oil equivalent basis. This large increase in the per barrel of oil equivalent depletion and depreciation expense is primarily due to the increase in the property and equipment balance from the conversion of exchangeable shares due to the application of EIC-151. The effect of EIC-151 on depletion and depreciation expense results in an increase of \$5.08 million or \$1.67 per barrel of oil equivalent. Additionally, the write-off of 2.4 billion cubic feet of proved reserves related to the production loss at a significant well in the West Central Alberta core area also factors into the increase. The 2004 increase from 2003 resulted from a December 31, 2003 year-over-year 14 percent reduction in the Trust's proved reserves as calculated pursuant to the implementation of the National Instrument 51-101 standards of reserve disclosure policy.

Depletion and depreciation charges calculated on a unit of production method are based on total proved reserves with a conversion of six thousand cubic feet of natural gas being equivalent to one barrel of oil. The 2005 depletion calculation includes \$6.88 million of future capital expenditures to develop the Trust's reserves, but excludes \$14.72 million of unproven properties relating to undeveloped land.

Zargon's depletion and depreciation, on a barrel of oil equivalent basis, increased 35 percent in 2005 to \$12.31 from \$9.11 in 2004 and \$7.23 in 2003. Depletion and depreciation rates will be subject to continuing upward pressure as industry finding and development costs increase to reflect the new economics of the recent trends to substantially higher commodity prices.

Accretion of Asset Retirement Obligations

For the year ended December 31, 2005, the non-cash accretion expense for asset retirement obligations is \$1.20 million compared to \$1.08 million in 2004 and \$1.17 million in 2003. The significant assumptions used in this calculation are a credit adjusted risk-free rate of 7.5 percent, an inflation rate of two percent and the payments to settle the retirement obligations will be made over the next 30 years with the majority of the costs being incurred after 2012. The estimated net present value of the total asset retirement obligation is \$15.86 million as at December 31, 2005, based on a total future liability of \$62.54 million.

Unit-Based Compensation

Unit-based compensation was \$0.90 million in 2005 or \$2.78 million lower than the \$3.68 million expense in 2004. Of the 2004 amount, \$2.17 million was related to a one-time charge for the accelerated vesting of stock options related to the July 15, 2004 Arrangement. The remainder was primarily the expense for the trust unit rights incentive plan, which in 2004 were originally calculated using the intrinsic value method. In response to an emphasis by securities regulators that fair value methodologies be used, new measurement techniques have been developed in 2005 utilizing a fair value option-pricing model for such unit rights grants. Zargon has reassessed the previous unit rights grants under this fair value model and there is no significant impact on amounts previously recorded as 2004 unit-based compensation expense. Zargon will continue to use fair value methodologies, where possible, for future unit rights grants. These non-cash expenses will be recurring charges in future years if Zargon continues to grant employee and director trust unit rights.

The trust unit rights incentive plan allows the Trust to issue rights to acquire trust units to directors, officers, employees and service providers. The Trust is authorized to issue up to 1.82 million unit rights; however, the number of trust units reserved for issuance upon exercise of the rights shall not exceed 10 percent of the aggregate number of issued and outstanding trust units of the Trust. The plan allows for the holder of rights to either exercise the right based on the original grant price or on the original grant price reduced by a portion of the future distributions. Unit right grant prices are set at the market price for the trust units on the date the unit rights are issued. Trust unit rights granted under the plan generally vest over a three-year period and expire approximately five years from the grant date.

Future Income Taxes

Zargon's 2005 future tax expense decreased 95 percent to \$0.47 million when compared to the respective expenses for 2004 and 2003 of \$9.64 million and \$9.19 million. The effective future tax rate in 2005 (the first full year in the trust structure) was 1.1 percent and is no longer comparable to the 2004 future tax rate of 29.0 percent and the 2003 rate of 27.1 percent. Effectively, Zargon's future tax obligations are reduced as distributions are made from the Trust, and consequently it is anticipated that Zargon's effective 2006 future tax rate will continue to be at considerably lower levels than the future tax rates booked prior to Zargon's conversion into a trust.

Net Earnings

Zargon's 2005 net earnings were \$35.37 million, a \$14.74 million increase from \$20.63 million in 2004. The 2003 net earnings were \$24.36 million. The very strong 2005 increase was due primarily to the \$21.23 million increase in cash flow from operations as previously described. On a per diluted unit basis, 2005 net earnings were \$2.19 compared to \$1.20 in 2004 and \$1.33 in 2003.

On a barrel of oil equivalent basis, the 2005 earnings before non-controlling interest were \$13.58 compared to \$7.48 in 2004 and \$8.97 in 2003.

Reflecting primarily the reduction in future income taxes, the 2005 net earnings were 42 percent of cash flow from operations. The 2004 net earnings represented 32 percent of cash flow from operations compared to 45 percent of cash flow in 2003.

Capital Expenditures

Net capital expenditures in 2005 of \$54.68 million decreased three percent from \$56.27 million in 2004. The decrease in capital expenditures was a result of a decline in Zargon's 2005 net property acquisition program to \$1.23 million from the prior year's \$11.81 million purchase of producing Saskatchewan oil properties in the Williston Basin core area. In 2005, Zargon completed an expanded drilling program of 60 gross (53.5 net) wells and drilling and completion expenditures climbed commensurately by 24 percent to \$33.36 million. Of the total 2005 net capital expenditures, \$15.77 million was expended on West Central Alberta, \$19.07 million on Alberta Plains and \$19.84 million on Williston Basin properties.

CAPITAL EXPENDITURES

(\$ million)	2005	2004	2003
Undeveloped land	3.65	3.84	6.98
Geological and geophysical (seismic)	3.47	5.26	5.69
Drilling and completion of wells	33.36	26.94	17.30
Well equipment and facilities	11.78	8.42	7.33
Exploration and development	52.26	44.46	37.30
Property acquisitions	3.68	12.09	7.83
Property dispositions	(2.45)	(0.28)	(5.22)
Net property acquisitions	1.23	11.81	2.61
Corporate acquisitions assigned to property and equipment ⁽¹⁾	1.19	-	-
Total net capital expenditures ⁽¹⁾	54.68	56.27	39.91

(1) Amounts include capital expenditures acquired for cash and equity issuances.

LIQUIDITY AND CAPITAL RESOURCES

Zargon's financing philosophy and three sources of funding are as follows:

- Internally generated cash flow provides the basic level of funding for the Trust's annual capital expenditures program and for distributions to unitholders.
- Debt may be utilized for acquisitions or to expand capital programs when it is deemed appropriate. The Trust has an \$80 million syndicated committed credit facility. As at December 31, 2005, \$69.66 million or 87 percent of this facility is unutilized. The Trust has followed and intends to maintain a conservative debt policy.
- New equity, if available and if on favourable terms, can be utilized for acquisitions or to expand capital programs.

In 2005, the summation of the cash outflows pertaining to the net capital expenditure program (\$54.68 million) and the cash distributions to unitholders (\$37.44 million) exceeded by \$3.28 million the summation of the cash inflows coming from the cash flow from operations (\$84.97 million) plus the proceeds from the issuance of trust units (\$3.87 million).

CAPITAL SOURCES

(\$ million)	2005	2004	2003
Cash flow from operations	84.97	63.75	54.35
Changes in working capital and other	7.17	2.54	2.66
Change in bank debt	(3.89)	7.25	(18.30)
Reorganization costs	-	(9.44)	-
Cash distributions	(37.44)	(10.70)	-
Issuance of trust units	3.87	2.87	1.20
Total capital sources	54.68	56.27	39.91

Cash Flow from Operations

It is anticipated that Zargon's 2006 capital budget and cash distributions to unitholders will be financed through the Trust's cash flow from operations. Cash flow is partially influenced by factors that the Trust cannot control, such as commodity prices, the US/Canadian dollar exchange rates and interest rates. Zargon's 2006 estimated sensitivity to moderate fluctuations in these key business parameters is shown in the accompanying table.

CASH FLOW SENSITIVITY SUMMARY

	Change in 2006 Cash Flow	
	(\$ million)	(\$/unit)
Change of \$1.00 US/bbl in the price of WTI oil	0.86	0.04
Change in oil production of 100 bbl/d	0.82	0.04
Change of \$0.10 US/mcf in the price of NYMEX natural gas	0.74	0.04
Change in natural gas production of one mmcf/d	1.76	0.09
Change in \$0.01 in the \$US/\$Cdn exchange rate	1.39	0.07

Bank Debt

On September 30, 2005, a Canadian subsidiary and a US subsidiary of the Trust entered into syndicated committed credit facilities with a borrowing base of \$80 million, which replaces its former demand facility of \$50 million. These facilities consist of a \$60 million tranche available to the Canadian borrower and a US \$15 million tranche available to the US borrower. A \$150 million demand debenture on the assets of the subsidiaries of the Trust has been provided as security for these facilities. These facilities are fully revolving for a 364 day period with the provision for an annual extension at the option of the lenders and upon notice from the Company. Should the facilities not be renewed, they convert to one year non-revolving term facilities at the end of the revolving 364 day period. Repayment would not be required until the end of the non-revolving term, and as such, in accordance with Canadian GAAP, the revolving credit facility has been classified as long term debt as opposed to the previous facility which was treated as a current liability. At December 31, 2005, bank debt was \$10.34 million, a decrease of 27 percent from the prior year end bank indebtedness amount of \$14.23 million.

Zargon's debt net of working capital (excluding the unrealized risk management liability) of \$27.49 million at December 31, 2005 was equivalent to 32 percent of the 2005 cash flow from operations of \$84.97 million. At December 31, 2004, the debt net of working capital (excluding the unrealized risk management liability) was \$23.37 million, equivalent to 37 percent of the 2004 cash flow from operations of \$63.75 million.

Equity

At March 13, 2006, Zargon had 16.461 million trust units and 2.345 million exchangeable shares outstanding. Assuming full conversion of exchangeable shares at the effective exchange ratio of 1.12640, there would be 19.101 million trust units outstanding at this date. Pursuant to the trust unit rights incentive plan, there are currently an additional 0.986 million trust unit incentive rights issued and outstanding.

During 2005, 13.18 million Zargon trust units traded on The Toronto Stock Exchange with a high trading price of \$34.99 per unit, a low of \$20.75 per unit and a closing price of \$31.75 per unit. The 2005 trading statistics show a 26 percent year-over-year decrease in trading volume, and a 33 percent increase in the closing stock price. Zargon's market capitalization (including the market value of exchangeable shares) at year end 2005 was approximately \$603 million, compared to approximately \$444 million at the end of 2004.

Segmented Geographic Information

In calendar 2005, approximately 87 percent (2004 – 88 percent) of Zargon's combined petroleum and natural gas revenue came from Western Canadian (Alberta, Saskatchewan and Manitoba) properties, with the remaining 13 percent (2004 – 12 percent) of revenues generated in the United States (North Dakota and Montana).

CRITICAL ACCOUNTING ESTIMATES

The preparation of the consolidated financial statements in accordance with Canadian generally accepted accounting principles requires management to make judgments and estimates that affect the financial results of the Trust. Zargon's management reviews its estimates regularly, but new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. The critical estimates are discussed below:

Petroleum and Natural Gas Reserves

All of Zargon's petroleum and natural gas reserves are evaluated and reported on by independent petroleum engineering consultants in accordance with Canadian Securities Administrators' National Instrument 51-101 ("NI 51-101"). The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, commodity prices and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Trust expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels, and changes in costs and commodity prices.

Full Cost Accounting

Zargon follows the full cost method of accounting for petroleum and natural gas operations as outlined in Canadian Institute of Chartered Accountants ("CICA") accounting guideline "Oil and Gas Accounting – Full Cost" (AcG-16). Under this accounting method, all costs related to the exploration for and development of petroleum and natural gas reserves are capitalized. Capitalized costs, as well as the estimated future expenditures to develop proved reserves, are depleted using the unit-of-production method based on estimated proved oil and natural gas reserves.

In applying the full cost method, Zargon calculates a ceiling test on a quarterly basis to ensure that the net carrying value of petroleum and natural gas assets do not exceed the estimated undiscounted future net cash flows from production of proved reserves. Accordingly, the Trust must base this calculation of future net cash flows on estimated forecasted sales prices, costs and regulations in effect at the period end. AcG-16 limits the carrying value of petroleum and natural gas properties to their fair value. The fair value is equal to estimated future cash flows from proved and probable reserves using future price forecasts and costs discounted at a risk-free rate.

Asset Retirement Obligations

Effective January 1, 2004, Zargon adopted CICA Section 3110, "Asset Retirement Obligations", which requires liability recognition for retirement obligations associated with the Trust's property, plant and equipment. Under this policy, the Trust is required to provide for future removal and site restoration costs. The Trust must estimate these costs in accordance with existing laws, contracts or other policies and must also estimate a credit adjusted risk-free rate and inflation rate in this calculation. These estimated costs are charged to earnings and the appropriate liability account over the expected life of the asset. When the future removal and site restoration costs cannot be reasonably determined, a contingent liability may exist. Contingent liabilities are charged to earnings when management is able to determine the amount and the likelihood of the future obligation.

Income Tax Accounting

The determination of the Trust's income and other tax liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

RECENT CANADIAN ACCOUNTING PRONOUNCEMENTS

During 2005, the following new or amended standards and guidelines were issued:

Exchangeable Securities Issued by Subsidiaries of Income Trusts

On January 19, 2005, the CICA issued revised draft EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" which states that exchangeable securities issued by a subsidiary of an Income Trust should be reflected as either non-controlling interest or debt on the consolidated balance sheet unless they meet certain criteria. The exchangeable shares issued by Zargon Oil & Gas Ltd., a corporate subsidiary of the Trust, are publicly traded and have an expiry term, which could be extended at the option of the Board of Directors. Therefore, these securities are considered, by EIC-151, to be transferable to third parties and to have an indefinite life. EIC-151 states that if these criteria are met, the exchangeable shares should be reflected as non-controlling interest. Previously, the exchangeable shares were reflected as a component of unitholders' equity.

For the 2004 year end, the Trust retroactively restated prior periods back to the Plan of Arrangement dated July 15, 2004. As a result of this change in accounting policy, the Trust has increased its unitholders' equity and non-controlling interest for 2005 by \$24.44 million (2004 – \$10.15 million) on the Trust's consolidated balance sheet. Consolidated net earnings for 2005 have been reduced for net earnings attributable to the non-controlling interest of \$5.99 million (2004 – \$1.87 million). In accordance with EIC-151 and given the circumstances in Zargon's case, each redemption is accounted for as a step-purchase, which for 2005 additionally resulted in an increase in property and equipment of \$24.93 million (2004 – \$11.28 million), an increase in accumulated depletion and depreciation by \$5.08 million (2004 – nil), and an increase in future income tax liability of \$6.48 million (2004 – \$3.00 million). Cash flow was not impacted by this change.

The cumulative impact to date of the application of EIC-151 has been to increase gross property and equipment by \$36.21 million, unitholders' equity and non-controlling interest by \$34.59 million, future income tax liability by \$9.48 million and an allocation of net earnings to exchangeable shareholders' of \$7.86 million.

Financial Instruments – Recognition and Measurement

On January 27, 2005, the Accounting Standard's Board (AcSB) issued CICA Handbook section 3855 "Financial Instruments – Recognition and Measurement", CICA Handbook section 3861 "Financial Instruments – Disclosure and Presentation", CICA Handbook section 1530 "Comprehensive Income" and CICA handbook section 3865 "Hedges" that deal with the recognition and measurement of financial instruments and comprehensive income. The new standards are intended to harmonize Canadian standards with United States and International accounting standards and are effective for annual and interim periods in fiscal years beginning on or after October 1, 2006. These new standards will impact the Trust in future periods and the resulting impact will be assessed at that time.

Non-Monetary Transactions

In the quarter ending March 31, 2006, Zargon will adopt Section 3831 "Non-Monetary Transactions" issued by the CICA in June 2005. Under the new standard, a commercial substance test replaces the culmination of earnings test as the criteria for fair value measurement. In addition, fair value measurement is clarified. The Trust does not expect application of this new standard to have a material impact on its consolidated financial statements.

TRUST STRUCTURE DEVELOPMENT

No Change to Tax Treatment of Income Trusts

On November 23, 2005, the federal government of Canada announced a reduction in personal income taxes on dividends and an end to the consultation process initiated on September 8, 2005 to review the tax treatment of income trusts and flow-through entities. The government did not announce any changes to the tax treatment of income trusts and flow-through entities.

The Trust's management believes that the announcement reflects the overwhelming consensus of submissions received during the consultation process to reduce personal income tax on corporate dividends to correct the long-standing problem of double taxation of dividends at the federal level. The decision reduces the uncertainty surrounding income trust taxation and assists in balancing tax treatment between corporations and trusts.

BUSINESS RISKS

Zargon's external business risks arise from the uncertainty of oil and natural gas pricing, the uncertainty of interest and exchange rates, environmental and safety issues, and financial and liquidity considerations. Additional risk arises from the production performance of existing properties (including natural decline), the changes in tax, royalty and other regulatory standards and uncertain results from capital expenditure programs.

Oil and natural gas prices may fluctuate widely in response to many factors such as global and North American supply and demand, economic conditions, weather conditions, political stability, the supply and price of imported oil and liquefied natural gas, production and storage levels of North American natural gas, and government regulations. Zargon attempts to minimize pricing and currency exchange uncertainty with a risk management program that encompasses a variety of financial instruments. These include forward sales of oil and natural gas production (either through financial derivative transactions such as swaps or by physical contracts), put options on both oil and natural gas, costless collars (in which some potential high price gain is given up in return for potential low price support) and US dollar currency risk management transactions in different forms for up to 35 percent of its oil and natural gas production volumes. In general, the Trust seeks to use strategies that allow minimum price expectations to be met in order that distributions and capital programs can be funded. This strategy is designed mainly to protect the Trust against periods of unusually low commodity prices and by its nature is likely to produce significant risk management losses when prices are unusually high.

Environmental and safety risks are mitigated through compliance with provincial and federal environmental and safety regulations, by maintaining adequate insurance, and by adopting appropriate emergency response and employee safety procedures.

The Trust is subject to a broad range of laws and regulatory requirements. Changes in government regulations, including reporting requirements, income tax laws, operating practices, environmental protection requirements and royalty rates can have a significant impact on Zargon. Although Zargon has no control over these regulatory risks, the Trust actively monitors changes, participates in industry organizations and, when required, engages the assistance of third-party experts to assess the impact of such changes in the Trust's financial and operating results.

Financial and liquidity risks are reduced by limiting debt financing to conservative self-imposed debt to cash flow guidelines. Zargon maintains a low cash distribution to cash flow from operations ratio to ensure adequate funding is available for capital programs to sustain per unit production and reserves. Access to capital markets, if required for additional financing by either debt or equity issuances, is dependent upon maintaining strong performance and relationships with investors. A substantial portion of the Trust's accounts receivable are with companies in the oil and gas industry and are subject to normal industry credit risks. Management regularly monitors the ageing of receivable balances to mitigate this risk. With respect to financial instruments utilized for risk management purposes, the Trust partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

Zargon actively manages the risks of its capital programs and reserves by concentrating drilling and subsequent development activities in areas where it has demonstrated proven technical capabilities and understanding. Zargon's capital budget is managed to limit exposure so that significant capital is not risked on any one project or concept.

SELECTED QUARTERLY INFORMATION ⁽¹⁾

(\$ million, except per unit amounts)	2005				2004			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Petroleum and natural gas revenue	50.26	42.47	35.87	34.12	32.90	32.41	30.96	27.70
Cash flow from operations	26.62	21.85	19.01	17.48	15.36	16.13	16.53	15.73
Per unit – diluted	1.40	1.15	1.01	0.93	0.82	0.87	0.88	0.84
Net earnings ⁽¹⁾	17.45	6.30	6.48	5.14	5.33	4.22	5.54	5.54
Per unit – diluted ⁽¹⁾	1.06	0.39	0.41	0.32	0.34	0.28	0.29	0.30
Cash distributions	16.66	7.45	6.73	6.60	6.43	4.27	-	-
Cash distribution—per trust unit	1.02	0.46	0.42	0.42	0.42	0.28	-	-
Net capital expenditures ⁽²⁾	19.12	13.91	10.96	10.69	15.25	23.64	7.61	9.77
Total assets ⁽¹⁾	277.86	264.44	253.75	245.20	226.96	215.23	189.80	186.18
Bank debt	10.34	11.43	15.52	18.23	14.23	9.77	-	3.67

(1) Comparative period numbers reflect the retroactive restatements due to changes in accounting policies.

(2) Amounts include capital expenditures acquired for cash and equity issuances.

FOURTH QUARTER 2005 HIGHLIGHTS

During the fourth quarter of 2005, Zargon's petroleum and natural gas revenues of \$50.26 million were 18 percent higher than the previous quarter's revenues. Production for the 2005 fourth quarter of 8,651 barrels of oil equivalent per day exceeded the fourth quarter guidance of 8,500 barrels of oil equivalent per day by two percent and was eight percent higher than the 2005 third quarter's production of 8,036 barrels of oil equivalent per day. Compared to the previous quarter, oil production increased 13 percent to 4,030 barrels per day as two successful higher rate Williston Basin horizontal wells were drilled and placed on production. Fourth quarter natural gas production increased four percent over the previous quarter to 27.73 million cubic feet per day as recently drilled West Central Alberta and Alberta Plains natural gas wells were tied-in to help offset the previous quarter's production losses at a significant well in the West Central Alberta core area. Average prices received during the fourth quarter, before risk management losses, were \$57.58 per barrel for oil and liquids and \$11.34 per thousand cubic feet for natural gas, a 13 percent reduction and a 34 percent increase respectively, compared to the 2005 third quarter prices. Reflecting market and seasonal trends, Zargon's field price differential for its blended 30 degree API crude oil stream increased to a \$13.59 per barrel discount to the Edmonton reference crude oil price, a 24 percent increase from Zargon's average differential of \$10.92 per barrel for the first nine months of 2005.

Cash flow from operations was \$26.62 million in the fourth quarter, an increase of 22 percent or \$4.77 million over the prior quarter. A comparative analysis of the primary factors that caused this quarter-over-quarter increase are as follows:

- Realized risk management losses increased by \$0.50 million to \$3.12 million, a 19 percent increase over the prior quarter's \$2.62 million of risk management losses. The primary reason for the increase in the fourth quarter related to losses on natural gas risk management contracts due to the high natural gas prices received throughout the quarter.
- Royalties for the fourth quarter were \$11.59 million, an increase of \$1.81 million from the prior quarter. The average royalty rate for the quarter held relatively steady at 23.1 percent from 23.0 percent from the third quarter.
- Production expenses held steady at \$6.10 million for the quarter, a \$0.19 million or three percent decrease from the third quarter of 2005. On a per barrel of oil equivalent basis, production expenses decreased 10 percent to \$7.67 in the fourth quarter 2005 compared to \$8.52 in the prior quarter. The quarterly improvement in per unit costs reflected the impact of the addition of higher-rate lower-cost wells that were responsible for the Trust's eight percent quarter-over-quarter production gain.

- General and administrative expenses increased in the fourth quarter by \$0.49 million over the third quarter of 2005. This is a 32 percent increase compared to the prior quarter and is primarily due to amounts recorded for year end performance-based compensation for employees.
- Interest and financing charges in the fourth quarter were \$0.23 million, an increase of 35 percent or \$0.06 million from the prior quarter. This increase is primarily due to additional costs related to the Trust's new syndicated committed credit facility which was closed and available on September 30, 2005. The average debt level for the fourth quarter declined slightly to \$16.40 million compared to \$17.63 million in the third quarter of 2005.
- Capital and current income taxes increased by \$0.36 million from the third quarter of 2005. The increase was due to increases in Canadian capital taxes and an increase in United States current income taxes incurred as a result of strengthening United States operations.

Net earnings for the quarter increased \$11.16 million to \$17.45 million, a 177 percent increase compared to the third quarter 2005 net earnings of \$6.30 million. Net earnings track the cash flow from operations for the respective periods modified by non-cash charges, which included the following for the fourth quarter of 2005:

- Unit-based compensation expense increased by \$0.06 million during the fourth quarter of 2005 to \$0.24 million, a 32 percent increase over the third quarter. The increase is a result of additional unit rights grants in the fourth quarter of 2005.
- Depletion and depreciation expense increased by \$1.04 million to \$10.36 million in the fourth quarter. The additional expense resulted from the use of an updated depletion and depreciation rate of \$13.02 per barrel of oil equivalent, compared to the prior quarter's \$12.61 per barrel of oil equivalent charge. The increased per unit charges are calculated on the basis of the recently completed 2005 year end reserve appraisal prepared by independent engineers that reflects Zargon's and the ongoing industry's trend to higher finding and development costs, which are commensurate with the new economics of this current era of substantially higher commodity prices. Furthermore, 2005 depletion and depreciation rates continue to increase quarterly as a result of ongoing increases in the property and equipment balance from the conversion of exchangeable shares due to the application of EIC-151. Additionally, the 2005 third quarter write-off of proved reserves of 2.4 billion cubic feet related to the production loss at a significant well in the West Central Alberta core area also factors into the fourth quarter increase.
- Unrealized risk management losses in the third quarter of \$5.30 million reverted to gains in the 2005 fourth quarter of \$4.89 million. These unrealized gains and losses result from "marking-to-market" risk management contracts at each period end. During the fourth quarter, unrealized risk management gains were primarily driven by weaker commodity pricing at the December 31, 2005 marking-to-market date when compared to the third quarter September 30, 2005 marking-to-market date. In particular, lower year end futures natural gas pricing resulted in gains of \$3.27 million, and moderately lower year end futures oil pricing resulted in gains of \$1.62 million.
- Future income tax expense was \$0.33 million during the quarter, compared to a future income tax recovery of \$0.23 million from the third quarter of 2005. As cash distributions are made from the Trust, future tax expenses decline. During the fourth quarter, in addition to regular monthly distributions, a supplemental cash distribution was declared to unitholders. Future income taxes increased in the 2005 fourth quarter despite increased cash distributions due to the significant increase of earnings before taxes to \$21.20 million from the third quarter earnings before taxes of \$7.36 million.
- Non-controlling interest related to exchangeable shares increased to \$2.81 million in the 2005 fourth quarter, from \$1.05 million in the third quarter. This was due to an increase in net earnings before non-controlling interest in the fourth quarter.

Net capital expenditures were \$19.12 million during the fourth quarter of 2005, a 37 percent increase from the prior quarter amount of \$13.91 million. During the fourth quarter, Zargon completed a record field capital program focused on more expensive activities in the West Central Alberta and Williston Basin core areas. The fourth quarter capital expenditures were complemented with the corporate acquisition of a small private Saskatchewan oil and gas company for consideration of \$1.19 million. During the fourth quarter of 2005, 15.3 net wells were drilled, compared to 16.2 net wells in the third quarter of 2005.

On November 14, 2005, Zargon announced its monthly distribution rate would be increased an additional \$0.02 per unit to \$0.18 per unit commencing with the November distribution. A supplemental distribution (over-and-above the monthly distribution) was declared in December 2005 of \$0.50 per unit, raising the distribution per unit to \$1.02 for the fourth quarter from \$0.46 in the prior quarter. Cash distributions to unitholders declared for the quarter totalled \$16.66 million, resulting in a quarterly payout ratio of 63 percent of cash flow or 73 percent on a per diluted trust unit basis. The upward spike in the fourth quarter was a result of the December 2005 supplemental distribution which represented a semi-annual adjustment pursuant to Zargon's strategy of distributing approximately 50 percent of the Trust's cash flows attributed to the unitholder.

ZARGON ENERGY TRUST

CONSOLIDATED BALANCE SHEETS

As at December 31 (\$ thousand)	2005	2004
ASSETS <i>[note 6]</i>		
Current		
Accounts receivable <i>[note 12]</i>	21,835	14,275
Prepaid expenses and deposits	2,710	2,953
	<u>24,545</u>	<u>17,228</u>
Property and equipment, net <i>[notes 4 and 5]</i>	253,315	209,736
	<u>277,860</u>	<u>226,964</u>
LIABILITIES		
Current		
Bank indebtedness <i>[note 6]</i>	-	14,230
Accounts payable and accrued liabilities	30,570	24,153
Cash distributions payable <i>[note 18]</i>	11,122	2,210
Unrealized risk management liability <i>[note 12]</i>	3,756	-
	<u>45,448</u>	<u>40,593</u>
Long term debt <i>[note 6]</i>	10,339	-
Asset retirement obligations <i>[note 7]</i>	15,859	14,390
Future income taxes <i>[note 10]</i>	48,928	41,830
	<u>120,574</u>	<u>96,813</u>
Commitments and contingencies <i>[notes 12, 13 and 14]</i>		
NON-CONTROLLING INTEREST		
Exchangeable shares <i>[notes 3 and 9]</i>	12,673	9,529
UNITHOLDERS' EQUITY		
Unitholders' capital <i>[note 8]</i>	71,644	45,755
Contributed surplus <i>[note 8]</i>	1,347	1,170
Accumulated earnings	119,768	84,399
Accumulated cash distributions <i>[note 18]</i>	(48,146)	(10,702)
	<u>144,613</u>	<u>120,622</u>
	<u>277,860</u>	<u>226,964</u>

See accompanying notes to the consolidated financial statements.

ZARGON ENERGY TRUST

CONSOLIDATED STATEMENTS OF EARNINGS AND ACCUMULATED EARNINGS

For the years ended December 31
(\$ thousand, except per unit amounts)

	<u>2005</u>	<u>2004</u>
Revenue		
Petroleum and natural gas revenue	162,722	123,968
Unrealized risk management loss <i>[note 12]</i>	(3,756)	-
Realized risk management loss <i>[note 12]</i>	(7,754)	(4,568)
Royalties (net of Alberta Royalty Credit)	(37,319)	(28,047)
	<u>113,893</u>	<u>91,353</u>
Expenses		
Production	24,035	21,692
General and administrative <i>[note 20]</i>	6,053	4,358
Unit-based compensation <i>[note 8]</i>	902	3,682
Interest and financing charges <i>[note 6]</i>	786	440
Unrealized foreign exchange gain	(201)	(564)
Accretion of asset retirement obligations <i>[note 7]</i>	1,196	1,076
Depletion and depreciation	37,484	27,414
	<u>70,255</u>	<u>58,098</u>
Earnings before income taxes	<u>43,638</u>	<u>33,255</u>
Income taxes <i>[note 10]</i>		
Future	474	9,639
Current	1,801	1,114
	<u>2,275</u>	<u>10,753</u>
Earnings for the year before non-controlling interest	41,363	22,502
Non-controlling interest – exchangeable shares <i>[notes 3 and 9]</i>	<u>(5,994)</u>	<u>(1,870)</u>
Net earnings for the year	35,369	20,632
Accumulated earnings, beginning of year	84,399	70,005
Reorganization costs upon trust conversion <i>[note 19]</i>	<u>-</u>	<u>(6,238)</u>
Accumulated earnings, end of year	<u>119,768</u>	<u>84,399</u>
Net earnings per unit <i>[note 11]</i>		
Basic	2.21	1.23
Diluted	2.19	1.20

See accompanying notes to the consolidated financial statements.

ZARGON ENERGY TRUST

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 (\$ thousand)	2005	2004
Operating activities		
Net earnings for the year	35,369	20,632
Add (deduct) non-cash items:		
Non-controlling interest – exchangeable shares	5,994	1,870
Unrealized risk management loss	3,756	-
Depletion and depreciation	37,484	27,414
Accretion of asset retirement obligations	1,196	1,076
Unit-based compensation	902	3,682
Unrealized foreign exchange gain	(201)	(564)
Future income taxes	474	9,639
	84,974	63,749
Asset retirement expenditures	(604)	(414)
Changes in non-cash working capital <i>[note 15]</i>	(1,401)	19
	82,969	63,354
Financing activities		
Advances (repayment) of bank debt	(3,891)	7,252
Cash distributions to unitholders	(37,444)	(10,702)
Exercise of unit rights	2,723	2,867
Changes in non-cash working capital <i>[note 15]</i>	8,974	2,148
	(29,638)	1,565
Investing activities		
Additions to property and equipment	(55,986)	(56,553)
Proceeds on disposal of property and equipment	2,446	280
Reorganization costs <i>[note 19]</i>	-	(9,443)
Changes in non-cash working capital <i>[note 15]</i>	209	797
	(53,331)	(64,919)
Change in cash, and cash end of year	-	-

See supplementary information contained in note 16.

See accompanying notes to the consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2005 and 2004.

All amounts are stated in Canadian dollars unless otherwise stated.

1. STRUCTURE OF THE TRUST

On July 15, 2004, Zargon Oil & Gas Ltd. (the "Company") was reorganized into Zargon Energy Trust (the "Trust" or "Zargon") as part of a Plan of Arrangement (the "Arrangement"). Shareholders of the Company received one trust unit or one exchangeable share for each common share held. All outstanding common share options were settled for cash prior to the completion of the reorganization. The unitholders of the Trust are entitled to receive cash distributions paid by the Trust. Holders of exchangeable shares are not eligible to receive cash distributions paid, but rather, on each payment of a distribution, the number of trust units into which each exchangeable share is exchangeable is increased on a cumulative basis in respect of the distribution. The Trust is an unincorporated open-end investment trust established under the laws of the Province of Alberta and was created pursuant to a trust indenture ("Trust Indenture").

The Trust's principal business activity is the exploration for and development and production of petroleum and natural gas in Canada and the United States ("US").

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation and Basis of Presentation

These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. Because a precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements necessarily involves the use of estimates and approximations. Accordingly, actual results could differ from those estimates. The consolidated financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the Trust's accounting policies summarized below.

While the Trust commenced operations on July 15, 2004, these consolidated financial statements follow the continuity of interest basis of accounting as if the Trust had always existed. This basis is intended to provide unitholders with meaningful and comparative financial information.

The consolidated financial statements include the accounts of Zargon Energy Trust, all subsidiaries and a partnership. All subsidiaries and the partnership are directly or indirectly owned and their operations are fully reflected in the consolidated financial statements.

Revenue Recognition

Petroleum and natural gas revenue is recognized in earnings when reserves are produced and delivered to the purchaser.

Joint Operations

The majority of the petroleum and natural gas operations of the Trust are conducted jointly with others, and accordingly, these financial statements reflect only the proportionate interests of the Trust in such activities.

Property and Equipment

The Trust follows the full cost method of accounting for its oil and natural gas operations whereby all costs relating to the acquisition, exploration and development of oil and natural gas reserves are capitalized and accumulated in separate cost centres for Canada and the United States. Such costs include land acquisition costs, annual carrying charges of non-producing properties, geological and geophysical costs, and costs of drilling and equipping wells.

Depletion and depreciation of petroleum, natural gas properties and equipment is computed using the unit of production method based on the estimated proved reserves of petroleum and natural gas before royalties determined by independent consultants. For purposes of this calculation, reserves are converted to common units on the basis that six thousand cubic feet of natural gas is equivalent to one barrel of oil. A portion of the cost of petroleum and natural gas rights relating to undeveloped properties is excluded from the depletion calculation. Twenty percent of the year end balance of these costs is added to the depletion base each year. Proceeds on the disposal of petroleum and natural gas properties are applied against capitalized costs, with gains or losses not ordinarily recognized, unless such a disposal would result in a change in the depletion rate of 20 percent or more.

Depreciation of office equipment is provided using the declining balance method at an annual rate of 20 percent.

Impairment Test

The Trust applies an impairment test to petroleum, natural gas properties and equipment costs on a quarterly basis or more frequently as events or circumstances dictate. This impairment test is performed on both the Canadian and US cost centres. An impairment loss exists when the carrying amount of the Trust's petroleum, natural gas properties and equipment exceeds the estimated undiscounted future net cash flows associated with the Trust's proved reserves (before royalties). If an impairment loss is determined to exist, the costs carried on the balance sheet in excess of the fair value of the Trust's proved and probable reserves are charged to income. Reserves are determined pursuant to evaluation by independent engineers as dictated by National Instrument 51-101.

Asset Retirement Obligations

Zargon recognizes the fair value of an Asset Retirement Obligation ("ARO") in the period in which it is incurred when a reasonable estimate of the fair value can be made. The fair value of the estimated ARO is recorded as a liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on the unit-of-production method based on proved reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is expensed in the period. Actual costs incurred upon the settlement of the ARO are charged against the liability. Differences between the actual costs incurred and the fair value of the liability recorded are recognized to earnings in the period incurred.

Financial Instruments

Derivative financial instruments are utilized to reduce commodity price risk associated with the Trust's production of oil and natural gas. The base prices for the commodities are sometimes denominated in US dollars and the Trust may also use such financial instruments to reduce the related foreign currency risk. Financial instruments may also be used from time to time to reduce interest rate risk on outstanding debt. The Trust does not enter into financial instruments for trading or speculative purposes.

The Trust follows a policy of using risk management instruments such as fixed price swaps, forward sales, puts and costless collars. The objective is to partially offset or mitigate the wide price swings commonly encountered in oil and natural gas commodities and in so doing protect a minimum level of cash flow in periods of low commodity prices.

For financial risk management contracts entered into prior to December 31, 2004, the Trust's policy was to designate each derivative financial instrument employed as a hedge of a specific portion of projected production over the term of the instrument. The Trust formally documented its risk management objectives and strategies for undertaking the hedged transactions, the hedging item, the nature of the specific risk exposures being hedged, the intended term of the hedge relationship, the method for assessing effectiveness and the method of accounting for the hedging relationship. The effectiveness of the derivative is assessed on an ongoing basis to ensure that the derivatives entered into are highly effective in offsetting changes in fair values of the hedged items. The instruments employed may be denominated in US or Canadian dollars. Gains or losses from all hedging contracts, other than forward sales settled by physical delivery, are recognized as hedging gains or losses when the sale of hedged production occurs. The Trust believes these derivative

financial instruments used are effective as hedges over their term. In the event that a designated hedged item ceases to exist, any realized or unrealized gain or loss on such derivative commodity instruments is recognized in income immediately. If the hedge relationship is terminated, either via ineffectiveness or via termination of the designation, gains or losses previously deferred continue to be deferred and recognized when they are realized.

For financial risk management contracts entered into after December 31, 2004, the Trust does consider these contracts to be effective on an economic basis but has decided not to designate these contracts as hedges for accounting purposes and, accordingly, for outstanding contracts not designated as hedges, an unrealized gain or loss is recorded based on the fair value (mark-to-market) of the contracts at the period end. These instruments have been recorded as an unrealized risk management liability in the consolidated balance sheet.

In the case of forward sales, the instrument can sometimes be satisfied by physical delivery. In the case of physical delivery, the payment is part of the normal revenue stream.

Foreign currency swap agreements may be used from time to time to manage the risk inherent in producing commodities whose price is based directly or indirectly on US dollars, using a notional principal equal to the projected monthly revenue from their sale. Payments or charges are calculated and paid according to the terms of the agreement, usually with monthly settlement. At December 31, 2005 and 2004 the Trust had no such financial instruments.

Income Taxes

The Trust follows the liability method of tax allocation in accounting for income taxes. Under this method, the Trust records future income taxes for the effect of any differences between the accounting and income tax basis of an asset or liability using income tax rates expected to apply in the years in which these temporary differences are expected to be recovered or settled. The effect on future income tax assets and liabilities of a change in tax rates is recognized in net earnings in the period in which the change is substantively enacted.

Foreign Currency Translation

The Trust uses the temporal method of foreign currency translation whereby the monetary assets and liabilities recorded in a foreign currency are translated into Canadian dollars at year end exchange rates, and non-monetary assets and liabilities at the exchange rates prevailing when the assets were acquired or liability incurred. Revenues and expenses are translated at the average rate of exchange for the year. Gains and losses on translation are included in the consolidated statements of earnings.

Trust Unit Rights and Unit-Based Compensation

Under the Trust's unit rights incentive plan (the "Plan"), rights to purchase trust units are granted to directors, officers and employees at current market prices. The Plan allows for the exercise price of rights to be reduced in future periods by an amount that distributions exceed a stated return on assets. The unit-based compensation expense arising from unit rights granted upon the July 15, 2004 Plan of Arrangement and up to December 31, 2004 were originally calculated using the intrinsic value method. In response to an emphasis by securities regulators that fair value methodologies be used, new measurement techniques in 2005 have been developed utilizing a fair value option-pricing model for such unit rights grants. Zargon has reassessed the previous unit rights grants under this fair value model and there is no significant impact on amounts previously recorded as 2004 unit-based compensation expense. Zargon will continue to use fair value methodologies, where possible, for future unit rights grants. Under the fair value method of accounting for unit-based compensation the cost of the option is charged to earnings with an offsetting amount recorded to contributed surplus, based on an estimate of the fair value using a Black-Scholes option-pricing model. No compensation expense has been recorded on options issued prior to 2003 (see note 8). Forfeiture of rights are recorded as a reduction in expense in the period in which they occur.

Per Unit Amounts

Per unit amounts are calculated using the weighted average number of trust units outstanding during the period. Diluted per unit amounts are calculated using the treasury stock method to determine the dilutive effect of unit-based compensation. The Trust follows the treasury stock method, which assumes that the proceeds received from “in-the-money” trust unit rights and unrecognized future unit-based compensation expense are used to repurchase units at the average market rate during the period. Diluted per unit amounts also include exchangeable shares using the “if-converted” method, whereby it is assumed the conversion of the exchangeable securities occurs at the beginning of the reporting period (or at the time of issuance if later).

Measurement Uncertainty

The amounts recorded for depletion and depreciation of property and equipment and the assessment of these assets for impairment are based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements of changes in such estimates in future periods could be material.

Inherent in the fair value calculation of asset retirement obligations, are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal and regulatory environments. To the extent future revisions to these assumptions impact the fair value of the existing asset retirement obligation liability, a corresponding adjustment is made to the property and equipment balance.

Cash Distributions

The Trust declares monthly distributions of cash to unitholders of record on the last day of each calendar month. Pursuant to the Trust’s policy, it will pay distributions to its unitholders subject to satisfying its financing covenants. Such distributions are recorded as distributions of equity upon declaration of the distribution.

3. CHANGES IN ACCOUNTING POLICIES

Exchangeable Shares – Non-Controlling Interest

On January 19, 2005, the CICA issued EIC-151 “Exchangeable Securities Issued by Subsidiaries of Income Trusts” that states that exchangeable securities issued by a subsidiary of an Income Trust should be reflected as either a non-controlling interest or debt on the consolidated balance sheet unless they meet certain criteria. The exchangeable shares issued by Zargon Oil & Gas Ltd., a corporate subsidiary of the Trust, are publicly traded and have an expiry term, which could be extended at the option of the Board of Directors. Therefore, these securities are considered, by EIC-151, to be transferable to third parties and to have an indefinite life. EIC-151 states that if these criteria are met, the exchangeable shares should be reflected as a non-controlling interest. Previously, the exchangeable shares were reflected as a component of unitholders’ equity.

For the 2004 year end, the Trust retroactively restated prior periods back to the Plan of Arrangement dated July 15, 2004. As a result of this change in accounting policy, the Trust has increased its unitholders’ equity and non-controlling interest for 2005 by \$24.44 million (2004 – \$10.15 million) on the Trust’s consolidated balance sheet. Consolidated net earnings for 2005 have been reduced for net earnings attributable to the non-controlling interest of \$5.99 million (2004 – \$1.87 million). In accordance with EIC-151 and given the circumstances in Zargon’s case, each redemption is accounted for as a step-purchase, which for 2005 additionally resulted in an increase in property and equipment of \$24.93 million (2004 – \$11.28 million), and an increase in future income tax liability of \$6.48 million (2004 – \$3.00 million). Cash flow was not impacted by this change.

The cumulative impact to date of the application of EIC-151 has been to increase gross property and equipment by \$36.21 million, (for depletion impact see note 5), unitholders’ equity and non-controlling interest by \$34.59 million, future income tax liability by \$9.48 million and an allocation of net earnings to exchangeable shareholders’ of \$7.86 million.

4. ACQUISITION

On November 15, 2005, a subsidiary of the Trust acquired all of the outstanding shares of Simoil Resources Ltd. ("Simoil"), a private oil and gas company, for consideration of \$1.19 million. Consideration consisted of \$0.04 million cash and the issuance of 40,000 Zargon trust units valued at \$28.60 per unit.

The results of operations for Simoil have been included in the consolidated financial statements since November 15, 2005.

The acquisition was accounted for by the purchase method as follows:

(\$ thousand)	<u>2005</u>
Property and equipment	1,702
Future income tax liability	(415)
Asset retirement obligations	<u>(101)</u>
Total consideration	<u>1,186</u>

5. PROPERTY AND EQUIPMENT

(\$ thousand)	<u>December 31, 2005</u>		
	<u>Cost</u>	<u>Accumulated Depletion and Depreciation</u>	<u>Net Book Value</u>
Petroleum, natural gas properties and equipment*	387,113	134,614	252,499
Office equipment	1,664	848	816
	<u>388,777</u>	<u>135,462</u>	<u>253,315</u>

(\$ thousand)	<u>December 31, 2004</u>		
	<u>Cost</u>	<u>Accumulated Depletion and Depreciation</u>	<u>Net Book Value</u>
Petroleum, natural gas properties and equipment*	306,812	97,680	209,132
Office equipment	1,304	700	604
	<u>308,116</u>	<u>98,380</u>	<u>209,736</u>

**As a result of shareholders redeeming exchangeable shares, property and equipment has cumulatively increased \$36.21 million, \$24.93 million relating to 2005 and \$11.28 million relating to 2004. The effect of these increases has resulted in additional depletion and depreciation expense of approximately \$5.08 million which all relates to 2005.*

At December 31, 2005, petroleum, natural gas properties and equipment include \$14.72 million (2004 – \$14.70 million) relating to undeveloped properties that have been excluded from the depletion calculation.

An impairment test calculation was performed on the Trust's petroleum, natural gas properties and equipment at December 31, 2005 in which the estimated undiscounted future net cash flows associated with the proved reserves exceeded the carrying amount of the Trust's petroleum, natural gas properties and equipment. This impairment calculation was performed separately on both the Canadian and US cost centres.

The following table outlines benchmark prices used in the impairment test at December 31, 2005:

Year	WTI Crude Oil (\$US/bbl)	Exchange Rate (\$US/\$Cdn)	WTI Crude Oil (\$Cdn/bbl)	AECO Gas (\$Cdn/gi)
2006	64.37	0.88	73.15	9.93
2007	64.83	0.88	73.67	10.06
2008	62.87	0.88	71.44	9.33
2009	60.69	0.88	68.97	8.50
2010	59.51	0.88	67.62	7.86
Thereafter (inflation %)	2.0%	0.88	2.0%	2.0%

Actual prices used in the impairment test were adjusted for commodity price differentials specific to Zargon.

6. LONG TERM DEBT

On September 30, 2005, a Canadian subsidiary and a US subsidiary of the Trust entered into syndicated committed credit facilities with a borrowing base of \$80 million which replaces its former demand facility of \$50 million. These facilities consist of a \$60 million tranche available to the Canadian borrower and a US \$15 million tranche available to the US borrower. A \$150 million demand debenture on the assets of the subsidiaries of the Trust has been provided as security for these facilities. The facilities are fully revolving for a 364 day period with the provision for an annual extension at the option of the lenders and upon notice from the Company. Should the facilities not be renewed, they convert to one year non-revolving term facilities at the end of the revolving 364 day period. Repayment would not be required until the end of the non-revolving term, and as such, the revolving credit facility has been classified as long term debt. Interest rates fluctuate under the syndicated facility with Canadian prime, US prime, and US base rates plus an applicable margin between zero basis points and 25 basis points, as well as with Canadian banker's acceptance and LIBOR rates plus an applicable margin between 90 basis points and 150 basis points. At December 31, 2005, \$10.34 million had been drawn on the syndicated committed credit facilities bearing interest at Canadian prime (December 31, 2005 – 5.0 percent) with any unused amounts subject to standby fees. In the normal course of operations Zargon enters into various letters of credit. At December 31, 2005, the approximate value of outstanding letters of credit totalled \$0.47 million (2004 – \$0.46 million).

In 2004 and up until September 30, 2005, the Trust had a revolving demand credit facility that provided for a line of credit of \$50 million bearing interest at prime (December 31, 2004 – 4.25 percent) and had pledged an assignment of accounts receivable, a first floating charge on all of the Canadian assets and a fixed charge over certain property and equipment as collateral.

7. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligation was estimated by management based on Zargon's net working interest in all wells and facilities, estimated costs to reclaim and abandon wells and facilities and the estimated timing of the costs to be incurred in future periods. Zargon has estimated the net present value of its total asset retirement obligations to be \$15.86 million (2004 – \$14.39 million) as at December 31, 2005, based on a total future liability of \$62.54 million (2004 – \$59.12 million). These payments are expected to be made over the next 30 years with the majority of the costs being incurred after 2012. Commencing July 1, 2005, incremental asset retirement obligations are calculated using a revised credit adjusted risk-free rate of 7.5 percent. Asset retirement obligations prior to this period were calculated using a credit adjusted risk-free rate of 8.5 percent. An inflation rate of two percent used in the calculation of the present value of the asset retirement obligation remains unchanged.

The following table reconciles Zargon's asset retirement obligation:

(\$ thousand)	Year Ended December 31,	
	2005	2004
Balance, beginning of year	14,390	12,194
Liabilities incurred	906	1,696
Liabilities settled	(604)	(414)
Accretion expense	1,196	1,076
Foreign exchange	(29)	(162)
Balance, end of year	15,859	14,390

8. UNITHOLDERS' EQUITY

Pursuant to the Plan of Arrangement on July 15, 2004, 14.87 million units of the Trust and 3.66 million exchangeable shares (see note 9) of the Company were issued in exchange for all of the outstanding shares of the Company on a one-for-one basis.

The Trust is authorized to issue an unlimited number of voting trust units.

Trust Units

(thousand)	December 31, 2005		December 31, 2004	
	Number of Units	Amount (\$)	Number of Units	Amount (\$)
Units issued				
Balance, beginning of year	15,341	45,755	-	-
Issued pursuant to Plan of Arrangement July 15, 2004	-	-	14,866	36,219
Unit rights exercised for cash	153	2,723	-	-
Unit-based compensation recognized	-	725	-	-
Issued on conversion of exchangeable shares	821	21,297	475	9,536
Issued on corporate acquisition	40	1,144	-	-
Balance, end of year	16,355	71,644	15,341	45,755

Common Shares of Zargon Oil & Gas Ltd.

(no par value) (thousand)	December 31, 2004	
	Number of Shares	Amount (\$)
Shares issued		
Balance, beginning of year	17,992	42,200
Stock options exercised for cash	534	2,867
Stock-based compensation recognized	-	69
Trust units issued	(14,866)	(36,219)
Exchangeable shares issued	(3,660)	(8,917)
Balance, end of year	-	-

Compensation Plans

A summary of the status of the Trust's compensation expense for the years ended December 31, 2005 and 2004 is presented below:

Compensation Expense

(\$ thousand)	Year Ended December 31,	
	2005	2004
Stock-based compensation expense prior to Plan of Arrangement July 15, 2004	-	345
Accelerated vesting of unvested stock options pursuant to the Arrangement	-	2,167
Unit-based compensation recognized subsequent to trust conversion	902	1,170
Total for the year	902	3,682

A summary of the status of the Trust's compensation plans as at December 31, 2005 and 2004 and changes during the years ended on those dates is presented below:

Trust Unit Rights Incentive Plan

The Trust has a unit rights incentive plan (the "Plan") that allows the Trust to issue rights to acquire trust units to directors, officers, employees and service providers. The Trust is authorized to issue up to 1.82 million unit rights, however, the number of trust units reserved for issuance upon exercise of the rights shall not at any time exceed 10 percent of the aggregate number of issued and outstanding trust units of the Trust. At the time of grant, unit right exercise prices approximate the market price for the trust units. At the time of exercise, the rights holder has the option of exercising at the original grant price or the exercise price as calculated per the Arrangement. Rights granted under the plan generally vest over a three-year period and expire approximately five years from the grant date.

The following table summarizes information about the Trust's unit rights:

	December 31, 2005		December 31, 2004	
	Number of Unit Rights (thousand)	Weighted Average Exercise Price (\$/unit right)	Number of Unit Rights (thousand)	Weighted Average Exercise Price (\$/unit right)
Outstanding at beginning of year	579	17.79	-	-
Unit rights granted	505	26.89	579	17.79
Unit rights exercised	(153)	17.77	-	-
Unit rights cancelled	(16)	18.13	-	-
Outstanding at end of year	915	22.80	579	17.79
Unit rights exercisable at year end	48	17.70	-	-

The following table summarizes information about unit rights outstanding at December 31, 2005:

Range of Exercise Prices (\$/unit right)	Unit Rights Outstanding			Unit Rights Exercisable	
	Number Outstanding at 12/31/05 (thousand)	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price (\$/unit right)	Number Exercisable at 12/31/05 (thousand)	Weighted Average Exercise Price (\$/unit right)
17.70 – 19.25	411	3.1 years	17.78	48	17.70
22.00	162	4.1 years	22.00	-	-
25.06 – 27.40	171	4.1 years	27.35	-	-
31.09	171	4.1 years	31.09	-	-
	915		22.80	48	17.70

Unit-Based Compensation (See Compensation Expense Table Above)

The Plan allows for the exercise price of rights to be reduced in future periods by an amount that distributions exceed a stated return on assets. The unit-based compensation expense arising from unit rights granted upon the July 15, 2004 Plan of Arrangement and up to December 31, 2004 were originally calculated using the intrinsic value method. In response to an emphasis by securities regulators that fair value methodologies be used, new measurement techniques in 2005 have been developed utilizing a fair value option-pricing model for such unit rights grants. Zargon has reassessed the previous unit rights grants under this fair value model and there is no significant impact on amounts previously recorded as 2004 unit-based compensation expense. Zargon will continue to use fair value methodologies, where possible, for future unit rights grants.

The assumptions made for unit rights granted for 2005 include a volatility factor of expected market price of 27.9 percent, a weighted average risk-free interest rate of 3.6 percent, a dividend yield of 7.2 percent and a weighted average expected life of the unit rights of four years, resulting in unit-based compensation expense of \$0.90 million. In 2004, subsequent to the Arrangement, \$1.17 million of unit-based compensation expense was recognized.

Compensation expense associated with rights granted under the Plan is recognized in earnings on a straight-line basis over the vesting period of the unit rights with a corresponding increase or decrease in contributed surplus. The exercise of trust unit rights is recorded as an increase in trust units with a corresponding reduction in contributed surplus. Forfeiture of rights are recorded as a reduction in expense in the period in which they occur.

Stock Options

In 2004, as part of the Arrangement to reorganize Zargon Oil & Gas Ltd. into a Trust, all common share options, vested and unvested, were cancelled and the optionholders received a cash payment for the intrinsic value of the options.

	December 31, 2004	
	Number of Shares (thousand)	Weighted Average Exercise Price (\$/stock option)
Outstanding at beginning of year	1,297	7.05
Granted	430	16.00
Exercised	(534)	5.39
Cancelled prior to trust conversion	(9)	9.61
Cancelled immediately prior to trust conversion	(1,184)	11.03
Outstanding at end of year	-	-

Stock-Based Compensation (See Compensation Expense Table Above)

Compensation expense of \$0.34 million was recognized for the 2004 year as a result of regular vesting of unvested stock options granted prior to the Arrangement. Additionally, as a result of cancelling the stock-option plan pursuant to the Arrangement, compensation expense for the year ended December 31, 2004 of \$2.17 million resulted from the acceleration of unvested stock options. Both of these non-cash expenses were recognized as part of unit-based compensation expense on the 2004 income statement for the twelve month period.

Under this stock-option plan, the Company had calculated the value of stock-based compensation using a Black-Scholes option-pricing model to estimate the fair value of stock options at the date of grant.

Compensation expense for options granted under the stock-option plan was based on the estimated fair values at the time of the grant and the expense was recognized over the vesting period of the option.

The assumptions made for the options granted in 2004 include an annualized volatility factor of 26.3 percent, a weighted average risk-free interest rate of 3.3 percent, no dividend yield and a weighted average expected life of options of four years.

The following table summarizes information about the Trust's contributed surplus account:

Contributed Surplus

(\$ thousand)	
Balance, January 1, 2004	264
Stock-based compensation expense prior to Plan of Arrangement July 15, 2004	345
Stock-based compensation recognized on exercise of stock options	(69)
Accelerated vesting of unvested stock options pursuant to the Arrangement	2,167
Stock-options cancelled immediately prior to trust conversion	(2,707)
Balance at trust conversion	-
Unit-based compensation recognized subsequent to trust conversion	1,170
Balance, December 31, 2004	1,170
Unit-based compensation expense	902
Unit-based compensation recognized on exercise of unit rights	(725)
Balance, December 31, 2005	1,347

9. NON-CONTROLLING INTEREST - EXCHANGEABLE SHARES

Zargon Oil & Gas Ltd. is authorized to issue a maximum of 3.66 million exchangeable shares. The exchangeable shares are convertible into trust units at the option of the shareholder based on the exchange ratio, which is adjusted monthly to reflect the distribution paid on the trust units. Cash distributions are not paid on the exchangeable shares. During the year, a total of 0.78 million (2004 – 0.47 million) exchangeable shares were converted into 0.82 million (2004 – 0.48 million) trust units based on the exchange ratio at the time of conversion. At December 31, 2005, the exchange ratio was 1.09629 (2004 – 1.02583) trust units per exchangeable share. As set out in the Arrangement, the exchangeable shares are entitled to vote equally to the number of trust units for which each exchangeable share is convertible into a trust unit on the record date. The Board of Directors of Zargon Oil & Gas Ltd. hold the option to redeem all outstanding exchangeable shares for trust units on or before July 15, 2014. At such time, should the Board not extend the term of the shares, there will be no remaining non-controlling interest.

The Trust retroactively applied EIC-151 “Exchangeable Securities Issued by a Subsidiary of an Income Trust” in 2004. Per EIC-151, if certain conditions are met, the exchangeable shares issued by a subsidiary must be reflected as non-controlling interest on the consolidated balance sheet and in turn, net earnings must be reduced by the amount of net earnings attributed to the non-controlling interest.

The non-controlling interest on the consolidated balance sheet consists of the book value of exchangeable shares at the time of the Plan of Arrangement, plus net earnings attributable to the exchangeable shareholders, less exchangeable shares (and related cumulative earnings) redeemed. The net earnings attributable to the non-controlling interest on the consolidated statement of earnings represents the cumulative share of net earnings attributable to the non-controlling interest based on the trust units issuable for exchangeable shares in proportion to total trust units issued and issuable each period end.

Non-Controlling Interest - Exchangeable Shares

(thousand, except exchange ratio)	December 31, 2005		December 31, 2004	
	Number of Shares	Amount (\$)	Number of Shares	Amount (\$)
Non-controlling interest – exchangeable shares issued				
Balance, beginning of year	3,186	9,529	-	-
Issued pursuant to Plan of Arrangement July 15, 2004	-	-	3,660	8,917
Exchanged for trust units at book value and including earnings attributed since Plan of Arrangement	(784)	(2,850)	(474)	(1,258)
Earnings attributable to non-controlling interest	-	5,994	-	1,870
Balance, end of year	2,402	12,673	3,186	9,529
Exchange ratio, end of year	1.09629		1.02583	
Trust units issuable upon conversion of exchangeable shares, end of year	2,633		3,268	

The proforma total units outstanding at year end, including trust units outstanding, and trust units issuable upon conversion of exchangeable shares and after giving rise to the exchange ratio at the end of the year is 18.99 million units (2004 – 18.61 million units).

Immediately prior to the July 15, 2004 Plan of Arrangement, the Company had \$45.14 million in share capital. Upon conversion to the Trust structure these amounts were allocated \$36.22 million to trust units and \$8.92 million to exchangeable shares, based on the terms of the Arrangement.

The effect of EIC-151 on Zargon's unitholders' capital and exchangeable shares is as follows:

(\$ thousand)	Zargon Oil & Gas Ltd. Common Shares	Zargon Energy Trust Units	Zargon Oil & Gas Ltd. Exchangeable Shares	Total
Immediately prior to July 15, 2004				
Plan of Arrangement	45,136			
Plan of Arrangement July 15, 2004	(45,136)	36,219	8,917	
	-	36,219	8,917	45,136
Issued on redemption of exchangeable shares at book value	-	1,155	(1,155)	-
Effect of EIC-151	-	8,381	1,767	10,148
Balance at December 31, 2004	-	45,755	9,529	55,284
Issued on redemption of exchangeable shares at book value	-	1,909	(1,909)	-
Effect of EIC-151	-	19,388	5,053	24,441
Unit-based compensation recognized	-	725	-	725
Unit rights exercised for cash	-	2,723	-	2,723
Issued on corporate acquisition	-	1,144	-	1,144
Balance at December 31, 2005	-	71,644	12,673	84,317

10. INCOME TAXES

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 allocates all of its Canadian taxable income to the unitholders in accordance with the Trust Indenture, and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no current tax provision for Canadian income tax expense has been made in the Trust. Canadian Large Corporations tax, capital taxes, and US income taxes are provided for under current income tax expense.

In the Trust structure, payments are made between the Company and the Trust that result in the transferring of taxable income from the Company to individual unitholders. These payments may reduce future income tax liabilities previously recorded by the Company that would be recognized as a recovery of income tax in the period incurred.

Income taxes differ from the amounts which would be obtained by applying statutory income tax rates to earnings before income taxes as follows:

(\$ thousand)	2005	2004
Statutory income tax rate	38.86%	39.96%
Expected income taxes	16,958	13,289
Add (deduct) income tax effect of:		
Non-deductible Crown charges, net of Alberta Royalty Credit	5,058	4,928
Resource allowance	(5,062)	(4,438)
Rate adjustment	(1,674)	947
Cash distributions	(14,551)	(4,277)
Large corporation tax, capital taxes, and US income taxes	1,801	1,114
Other	(255)	(810)
	2,275	10,753

As at December 31, 2005, Zargon has exploration and development costs, unamortized petroleum and natural gas property expenditures, undepreciated capital costs and unamortized share issue costs available for deduction against future taxable earnings in aggregate of approximately \$90 million (2004 – \$79 million).

Future income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of Zargon's net future income tax liability are as follows:

(\$ thousand)	2005	2004
Net book value of property and equipment in excess of tax pools	46,088	33,279
Deferred partnership earnings	10,178	14,153
Asset retirement obligation	(5,631)	(5,107)
Unrealized risk management liability	(1,319)	-
Share issue costs	(19)	(126)
Alberta Royalty Credit	(369)	(369)
	48,928	41,830

11. WEIGHTED AVERAGE NUMBER OF TOTAL UNITS

(thousand)	2005 (units)	2004 (units)
Basic	16,003	16,818
Diluted	18,848	18,723

Dilution amounts of 2.85 million units (2004 – 1.91 million) were added to the weighted average number of units outstanding during the year in the calculation of diluted per unit amounts. These unit additions represent the dilutive effect of unit rights according to the treasury stock method, and also include exchangeable shares using the “if-converted” method. An adjustment to the numerator amount was required in the diluted calculation to provide for the earnings of \$5.99 million (2004 – \$1.87 million) attributable to the non-controlling interest pertaining to the exchangeable shareholders.

12. FINANCIAL INSTRUMENTS

Fair Value of Financial Assets and Liabilities

Financial instruments of the Trust consist of accounts receivable, deposits, bank indebtedness, accounts payable, cash distributions payable, unrealized risk management liability and long term debt. As at December 31, 2005 and 2004, there are no significant differences between the carrying values of these amounts and their estimated market values.

Credit Risk Management

Accounts receivable include amounts receivable for petroleum and natural gas sales that are generally made to large credit-worthy purchasers, and amounts receivable from joint venture partners that are recoverable from production. Accordingly, the Trust views credit risks on these amounts as low. Of Zargon's significant individual accounts receivable at December 31, 2005, approximately 32 percent was owing from one company (2004 – 28 percent).

The Trust is exposed to losses in the event of non-performance by counterparties to financial risk management contracts. The Trust minimizes credit risk associated with possible non-performance to these financial instruments by entering into contracts with only investment grade counterparties, limits on exposures to any one counterparty, and monitoring procedures. The Trust believes these risks are minimal.

Interest Rate Risk Management

Borrowings under bank credit facilities are market-rate-based (variable interest rates); thus carrying values approximate fair values.

Foreign Currency Risk Management

The Trust is exposed to fluctuations in the exchange rate between the Canadian dollar and the US dollar. Crude oil, and to a large extent natural gas prices, are based upon reference prices denominated in US dollars, while the majority of the Trust's expenses are denominated in Canadian dollars. When appropriate, the Trust enters into agreements to fix the exchange rate of Canadian dollars to US dollars in order to manage this risk.

Commodity Price Risk Management

The Trust is a party to certain financial instruments that have fixed the price of a portion of its oil and natural gas production. The Trust enters into these contracts for risk management purposes only, in order to protect a portion of its future cash flow from the volatility of oil and natural gas commodity prices. The Trust has outstanding contracts at December 31, 2005 as follows:

Financial Contracts Designated as Hedges at December 31, 2005:

	Rate	Price	Range of Terms	Fair Market Value Gain/(Loss) (\$ thousand)
Oil collar	200 bbl/d	\$36.00 US/bbl Put	Jan. 1/06–Jun. 30/06	(595)
		\$48.40 US/bbl Call		
Natural gas collar	3,000 gj/d	\$5.90/gj Put	Jan. 1/06–Mar. 31/06	(13)
		\$10.00/gj Call		
Total Fair Market Value, Financial Contracts Designated as Hedges				(608)

Financial Contracts Not Designated as Hedges at December 31, 2005:

	Rate	Price	Range of Terms	Fair Market Value Gain/(Loss) (\$ thousand)
Oil swaps	200 bbl/d	\$48.50 US/bbl	Jan. 1/06–Jun. 30/06	(591)
	300 bbl/d	\$51.83 US/bbl	Jan. 1/06–Dec. 31/06	(1,447)
	200 bbl/d	\$51.12 US/bbl	Jul. 1/06–Dec. 31/06	(547)
Oil collars	200 bbl/d	\$40.00 US/bbl Put	Jan. 1/06–Jun. 30/06	(568)
		\$49.05 US/bbl Call		
	200 bbl/d	\$52.00 US/bbl Put	Jan. 1/06–Dec. 31/06	-
		\$78.95 US/bbl Call		
	200 bbl/d	\$55.00 US/bbl Put	Jul. 1/06–Dec. 31/06	-
		\$78.05 US/bbl Call		
Natural gas swaps	1,000 gj/d	\$12.82/gj	Jan. 1/06–Mar. 31/06	249
	4,000 gj/d	\$9.31/gj	Apr. 1/06–Oct. 31/06	(501)
Natural gas collars	2,000 gj/d	\$6.50/gj Put	Jan. 1/06–Mar. 31/06	(225)
		\$8.80/gj Call		
	2,000 gj/d	\$7.00/gj Put	Jan. 1/06–Mar. 31/06	(126)
		\$9.35/gj Call		
	1,000 gj/d	\$9.50/gj Put	Nov. 1/06–Mar. 31/07	-
		\$12.50/gj Call		
	1,000 gj/d	\$10.50/gj Put	Nov. 1/06–Mar. 31/07	-
		\$13.18/gj Call		
Total Fair Market Value, Financial Contracts Not Designated as Hedges				(3,756)

Physical Contracts at December 31, 2005:

	Rate	Price	Range of Terms	Fair Market Value Gain/(Loss) (\$ thousand)
Natural gas fixed price	4,000 gj/d	\$7.92/gj	Apr. 1/06–Oct. 31/06	(1,692)
Natural gas collars	1,000 gj/d	\$8.47/gj Put	Jan. 1/06–Mar. 31/06	(49)
		\$9.50/gj Call		
	1,000 gj/d	\$8.50/gj Put	Nov. 1/06–Mar. 31/07	-
		\$12.85/gj Call		
	1,000 gj/d	\$9.50/gj Put	Nov. 1/06–Mar. 31/07	-
		\$13.50/gj Call		
Total Fair Market Value, Physical Contracts				(1,741)

Oil swaps and collars are settled against the NYMEX pricing index, whereas natural gas swaps, collars, and puts are settled against the AECO pricing index.

Financial risk management contracts in place as at December 31, 2004 were designated as hedges for accounting purposes and the Trust continues to monitor these contracts in determining the continuation of hedge effectiveness. For these contracts, realized gains and losses are recorded in the statement of earnings as the contracts settle and no unrealized gain or loss is recognized. The realized losses for 2005 were \$7.75 million (2004 – \$4.57 million). At December 31, 2005, an additional \$0.61 million would have been required to settle the above designated hedge contracts which all related to financial hedges. At December 31, 2004, \$1.14 million would have been received to settle the designated hedge contracts, of this amount \$0.71 million related to financial hedges and \$0.43 million related to physical hedges. Contracts settled by way of physical delivery are recognized as part of the normal revenue stream. These instruments have no book values recorded in the consolidated financial statements.

For financial risk management contracts entered into after December 31, 2004, the Trust does consider these contracts to be effective on an economic basis but has decided not to designate these contracts as hedges for accounting purposes and accordingly, for outstanding contracts not designated as hedges, an unrealized gain or loss is recorded based on the fair value (mark-to-market) of the contracts at the period end. The unrealized losses as at December 31, 2005 were \$3.76 million (2004 – nil). These instruments have been recorded as a liability in the consolidated balance sheet.

13. COMMITMENTS

The Trust is committed to future minimum payments for natural gas transportation contracts in addition to operating leases for office space, office equipment, vehicles and field equipment. Payments required under these commitments for each of the next four years are: 2006 – \$1.44 million; 2007 – \$0.57 million; 2008 – \$0.07 million; 2009 – \$0.02 million.

14. CONTINGENCIES AND GUARANTEES

In the normal course of operations, Zargon executes agreements that provide for indemnification and guarantees to counterparties in transactions such as the sale of assets and operating leases.

These indemnifications and guarantees may require compensation to counterparties for costs and losses incurred as a result of various events, including breaches of representations and warranties, loss of or damages to property, environmental liabilities or as a result of litigation that may be suffered by counterparties.

Certain indemnifications can extend for an unlimited period and generally do not provide for any limit on the maximum potential amount. The nature of substantially all of the indemnifications prevents the Trust from making a reasonable estimate of the maximum potential amount that might be required to pay counterparties as the agreements do not specify a maximum amount, and the amounts depend on the outcome of future contingent events, the nature and likelihood of which cannot be determined at this time.

The Trust indemnifies its directors and officers against any and all claims or losses reasonably incurred in the performance of their service to the Trust to the extent permitted by law. The Trust has acquired and maintains liability insurance for its directors and officers. The Trust is party to various legal claims associated with the ordinary conduct of business. The Trust does not anticipate that these claims will have a material impact on the Trust's financial position.

15. CHANGE IN NON-CASH WORKING CAPITAL

(\$ thousand)	Year Ended December 31,	
	2005	2004
Changes in non-cash working capital items:		
Accounts receivable	(7,560)	(2,092)
Prepaid expenses and deposits	243	(1,973)
Accounts payable and accrued liabilities	6,417	4,876
Cash distributions payable	8,912	2,210
Other	(230)	(57)
	<u>7,782</u>	<u>2,964</u>
Changes relating to operating activities	(1,401)	19
Changes relating to financing activities	8,974	2,148
Changes relating to investing activities	209	797
	<u>7,782</u>	<u>2,964</u>

16. SUPPLEMENTAL CASH FLOW INFORMATION

(\$ thousand)	2005	2004
Cash interest and financing charges paid	1,044	448
Cash taxes paid	1,911	794

17. SEGMENTED INFORMATION

Zargon's entire operating activities are related to exploration, development and production of oil and natural gas in the geographic segments of Canada and the US.

(\$ thousand)	2005		
	Canada	United States	Combined
Petroleum and natural gas revenue	141,869	20,853	162,722
Earnings before income taxes	34,890	8,748	43,638
Property and equipment, net	221,664	31,651	253,315
Total assets	244,416	33,444	277,860
Net capital expenditures ⁽¹⁾	49,251	5,433	54,684

(\$ thousand)	2004		
	Canada	United States	Combined
Petroleum and natural gas revenue	108,484	15,484	123,968
Earnings before income taxes	27,614	5,641	33,255
Property and equipment, net	184,860	24,876	209,736
Total assets	200,171	26,793	226,964
Net capital expenditures	51,464	4,809	56,273

(1) Amounts include capital expenditures acquired for cash and equity issuances.

18. ACCUMULATED CASH DISTRIBUTIONS

During the year, the Trust paid or declared distributions to the unitholders in the aggregate amount of \$37.44 million (2004 - \$10.70 million) in accordance with the following schedule:

<u>2005 Distributions</u>	<u>Record Date</u>	<u>Distribution Date</u>	<u>Per Trust Unit</u>
January 2005	January 31, 2005	February 15, 2005	\$0.14
February 2005	February 28, 2005	March 15, 2005	\$0.14
March 2005	March 31, 2005	April 15, 2005	\$0.14
April 2005	April 30, 2005	May 16, 2005	\$0.14
May 2005	May 31, 2005	June 15, 2005	\$0.14
June 2005	June 30, 2005	July 15, 2005	\$0.14
July 2005	July 31, 2005	August 15, 2005	\$0.14
August 2005	August 31, 2005	September 15, 2005	\$0.16
September 2005	September 30, 2005	October 17, 2005	\$0.16
October 2005	October 31, 2005	November 15, 2005	\$0.16
November 2005	November 30, 2005	December 15, 2005	\$0.18
December 2005	December 31, 2005	January 16, 2006	\$0.18
December 2005	December 31, 2005	January 16, 2006	\$0.50

<u>2004 Distributions</u>	<u>Record Date</u>	<u>Distribution Date</u>	<u>Per Trust Unit</u>
August 2004	August 31, 2004	September 15, 2004	\$0.14
September 2004	September 30, 2004	October 15, 2004	\$0.14
October 2004	October 31, 2004	November 15, 2004	\$0.14
November 2004	November 30, 2004	December 15, 2004	\$0.14
December 2004	December 31, 2004	January 17, 2005	\$0.14

19. ZARGON ENERGY TRUST REORGANIZATION

In 2004, the following costs were incurred to reorganize Zargon Oil & Gas Ltd. into a trust effective July 15, 2004:

(\$ thousand)

Cash payout of stock options	7,875
Financial advisory, accounting and legal fees, and preparation and printing of the Information Circular	1,568
Total reorganization costs	<u>9,443</u>

Of the above amounts, \$2.71 million was charged to contributed surplus relating to recognized stock-based compensation under the previous stock option plan for the Company. The remaining \$6.73 million (\$6.24 million net of taxes) was charged directly against accumulated earnings.

20. RELATED PARTY TRANSACTIONS

Zargon paid \$0.13 million (2004 – \$0.15 million) in consulting fees to a company owned by the Chairman of the Board; \$0.04 million (2004 – \$0.05 million) for vehicle leases to a company owned by a Board member; and \$0.12 million (2004 – \$0.53 million) for legal services to a law firm in which a Board member is a partner. These payments were in the normal course of operations, on commercial terms, and therefore were recorded at the exchange amount.

21. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform with the current year's financial statement presentation.

Forward-Looking Statements - This document contains statements that are forward-looking, such as those relating to results of operations and financial condition, capital spending, financing sources, commodity prices, costs of production and the magnitude of oil and natural gas reserves. By their nature, forward-looking statements are subject to numerous risks and uncertainties that could significantly affect anticipated results in the future and, accordingly, actual results may differ materially from those predicted. The forward-looking statements contained in this press release are as of March 13, 2006 and are subject to change after this date. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Zargon disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Based in Calgary, Alberta, Zargon's securities trade on the Toronto Stock Exchange (TSX). Trust units of Zargon trade under the symbol "ZAR.UN", exchangeable shares of Zargon trade under the symbol "ZOG.B".

In order to learn more about Zargon, we encourage you to visit Zargon's website at www.zargon.ca where you will find a current shareholder presentation, financial reports and historical news releases.

For further information please contact either:

C.H. Hansen
President and Chief Executive Officer

- or -

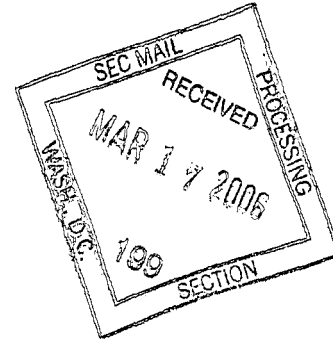
B.C. Heagy
Vice President, Finance and Chief Financial Officer

Zargon Energy Trust
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E-mail: zargon@zargon.ca
Website: www.zargon.ca

ZARGON

E N E R G Y T R U S T

March 16, 2006



Securities and Exchange Commission
100 F. Street, N.E.
Washington, D.C. 20549
Attention: Filing Desk

Dear Sir or Madame:

Re: Zargon Energy Trust
File No. 82-34907
Exemption Pursuant to Rule 12g3-2(b)

Pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934, as amended, enclosed is a copy of the Company's news release dated March 16, 2006. As required pursuant to Rule 12g3-2(b), the exemption number appears in the upper right-hand corner of each unbound page and of the first page of each bound document.

Please indicate your receipt of the enclosed by stamping the enclosed copy of this letter and returning it to the sender in the enclosed self-addressed, stamped envelope.

Yours truly,
ZARGON ENERGY TRUST

B.C. Heagy
Vice President Finance & CFO

BCH/th

Encl.

FILE NO: CE 01001
FOR IMMEDIATE RELEASE: March 16, 2006

TSX SYMBOL: ZAR.UN; ZOG.B

ZARGON ENERGY TRUST CONFIRMS MARCH 2006 CASH DISTRIBUTION

CALGARY, ALBERTA – Zargon Energy Trust ("Zargon") confirms that the monthly cash distribution for the month of March in the amount of Cdn. \$0.18 per trust unit will be paid on April 17, 2006 to unitholders of record on March 31, 2006. The ex-distribution date is March 29, 2006.

Based in Calgary, Alberta, Zargon's securities trade on the Toronto Stock Exchange and there are currently 16.472 million trust units (ZAR.UN) and 2.345 million exchangeable shares (ZOG.B) outstanding. After giving effect to the conversion privilege of the exchangeable shares and the March 16, 2006 revised exchange ratio there would be a total of 19.129 million trust units outstanding.

In order to learn more about Zargon, we encourage you to visit Zargon's website at www.zargon.ca where you will find a current shareholder presentation, financial reports and historical news releases.

For further information please contact either:

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