

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis (MD&A) is a review of Zargon Energy Trust's 2005 financial results and should be read in conjunction with the audited consolidated financial statements and related notes for the years ended December 31, 2005 and 2004. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). All amounts are in Canadian dollars unless otherwise noted. All references to "Zargon" or the "Trust" refer to Zargon Energy Trust and all references to the "Company" refer to Zargon Oil & Gas Ltd.

In the MD&A, reserves and production are commonly stated in barrels of oil equivalent (boe) on the basis that six thousand cubic feet of natural gas is equivalent to one barrel of oil (boe). Boes may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalent conversion method primarily applicable to the burner tip and does not represent a value equivalent at the wellhead.

The following are descriptions of non-GAAP measures used in this MD&A:

- The MD&A contains the term "cash flow from operations" ("cash flow"), which should not be considered an alternative to, or more meaningful than, "cash flow from operating activities" as determined in accordance with Canadian GAAP as an indicator of the Trust's financial performance. This term does not have any standardized meaning as prescribed by GAAP and therefore, the Trust's determination of cash flow from operations may not be comparable to that reported by other trusts. The reconciliation between net earnings and cash flow from operations can be found in the consolidated statements of cash flows in the consolidated financial statements. The Trust evaluates its performance based on net earnings and cash flow from operations. The Trust considers cash flow from operations to be a key measure as it demonstrates the Trust's ability to generate the cash necessary to pay distributions, repay debt and to fund future capital investment. It is also used by research analysts to value and compare oil and gas trusts, and it is frequently included in published research when providing investment recommendations. Cash flow from operations per unit is calculated using the diluted weighted average number of units for the period.
- Payout ratio equals distributions as a percentage of cash flow for the period. Payout ratio is a useful measure used by management to analyze the Trust's efficiency and sustainability.
- The Trust also uses the term "debt net of working capital". Debt net of working capital as presented does not have any standardized meaning prescribed by Canadian GAAP and may not be comparable with the calculation of similar measures for other entities. Debt net of working capital as used by the Trust is calculated as bank debt and any working capital deficit excluding the current portion of unrealized risk management assets or liabilities.
- Operating netbacks equal total petroleum and natural gas revenue per boe less realized risk management losses per boe, royalties per boe, and production costs per boe. Operating netbacks are a useful measure to compare the Trust's operations with those of its peers.
- Cash flow netbacks per boe are calculated as operating netbacks less general and administrative expenses per boe, interest and financing charges per boe, and capital and current income taxes per boe. Cash flow netbacks are a useful measure to compare the Trust's operations with those of its peers.

References to "production volumes" or "production" in this MD&A refer to sales volumes.

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 MD&A 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.

This MD&A has been prepared as of March 13, 2006.

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 MD&A 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

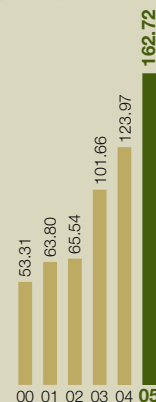
1. Amounts are before risk management losses.

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.

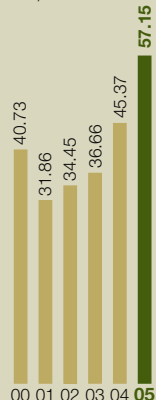
Petroleum and Natural Gas Revenue

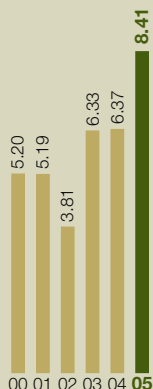
(\$ million)



Oil and Liquids Prices

(\$/bbl)



Natural Gas Prices
(\$/mcf)

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.

As at December 31, 2005, the Trust had the following outstanding commodity price risk management contracts:

FINANCIAL CONTRACTS DESIGNATED AS HEDGES

	Rate		Price	Range of Terms
Oil collar	200 bbl/d	\$36.00 US/bbl Put; \$48.40 US/bbl Call		Jan. 1/06 – Jun. 30/06
Natural gas collar	3,000 gj/d		\$5.90/gj Put; \$10.00/gj Call	Jan. 1/06 – Mar. 31/06

FINANCIAL CONTRACTS NOT DESIGNATED AS HEDGES

	Rate		Price	Range of Terms
Oil swaps	200 bbl/d		\$48.50 US/bbl	Jan. 1/06 – Jun. 30/06
	300 bbl/d		\$51.83 US/bbl	Jan. 1/06 – Dec. 31/06
	200 bbl/d		\$51.12 US/bbl	Jul. 1/06 – Dec. 31/06
Oil collars	200 bbl/d	\$40.00 US/bbl Put; \$49.05 US/bbl Call		Jan. 1/06 – Jun. 30/06
	200 bbl/d	\$52.00 US/bbl Put; \$78.95 US/bbl Call		Jan. 1/06 – Dec. 31/06
	200 bbl/d	\$55.00 US/bbl Put; \$78.05 US/bbl Call		Jul. 1/06 – Dec. 31/06
Natural gas swaps	1,000 gj/d		\$12.82/gj	Jan. 1/06 – Mar. 31/06
	4,000 gj/d		\$9.31/gj	Apr. 1/06 – Oct. 31/06
Natural gas collars	2,000 gj/d	\$6.50/gj Put; \$8.80/gj Call		Jan. 1/06 – Mar. 31/06
	2,000 gj/d	\$7.00/gj Put; \$9.35/gj Call		Jan. 1/06 – Mar. 31/06
	1,000 gj/d	\$9.50/gj Put; \$12.50/gj Call		Nov. 1/06 – Mar. 31/07
	1,000 gj/d	\$10.50/gj Put; \$13.18/gj Call		Nov. 1/06 – Mar. 31/07

PHYSICAL CONTRACTS

	Rate		Price	Range of Terms
Natural gas fixed price	4,000 gj/d		\$7.92/gj	Apr. 1/06 – Oct. 31/06
Natural gas collars	1,000 gj/d	\$8.47/gj Put; \$9.50/gj Call		Jan. 1/06 – Mar. 31/06
	1,000 gj/d	\$8.50/gj Put; \$12.85/gj Call		Nov. 1/06 – Mar. 31/07
	1,000 gj/d	\$9.50/gj Put; \$13.50/gj Call		Nov. 1/06 – Mar. 31/07

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

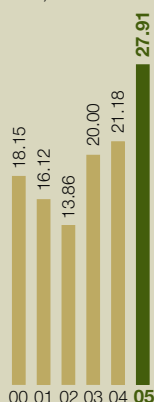
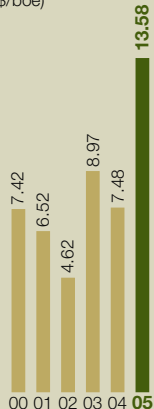
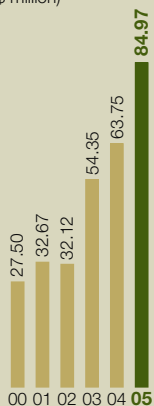
(\$ million, except as noted)	2005	2004	2003
Gross general and administrative expenses	8.96	7.23	5.94
Overhead recoveries	(2.91)	(2.87)	(2.40)
Net general and administrative expenses	6.05	4.36	3.54
Net expense after recoveries (\$/boe)	1.99	1.45	1.30
Number of office employees at year end	39	35	34

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

Cash Flow Netbacks
(\$/boe)**Earnings Before Non-Controlling Interest Netbacks**
(\$/boe)**Cash Flow from Operations**
(\$ million)

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 (see note at the beginning of the MD&A)

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

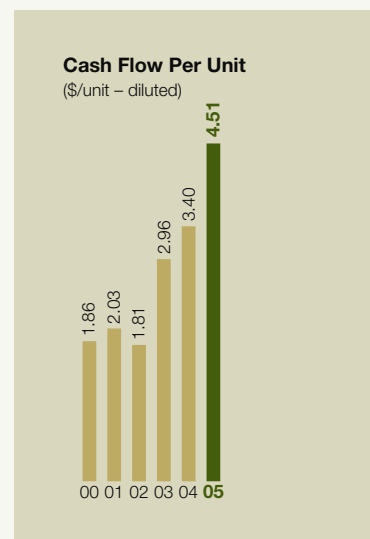
In 2005, Zargon's depletion and depreciation provision increased 37 percent to \$37.48 million, compared to \$27.41 million in 2004 and \$19.66 million in 2003. The higher charges reflect an increase of one percent in production volumes and a 35 percent increase in the charge on a per barrel of oil equivalent 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.

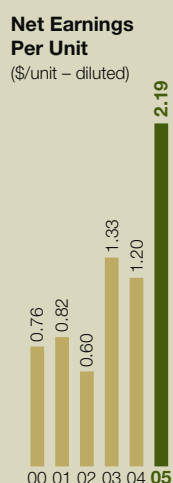
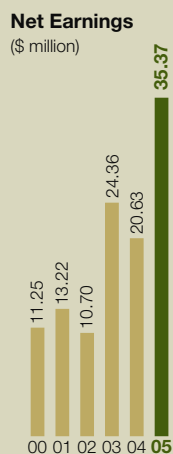
FUTURE INCOME TAXES

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

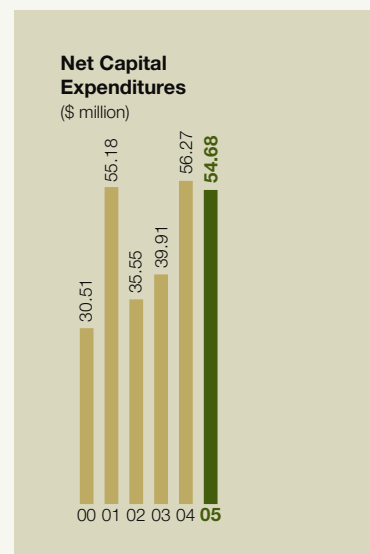
1. Amounts include capital expenditures acquired for cash and equity issuances.

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).

OFF BALANCE SHEET ARRANGEMENTS

The Trust has no guarantees or off balance sheet arrangements, except for letters of credit which have been issued in the normal course of business of approximately \$0.47 million as at December 31, 2005.

RELATED PARTY TRANSACTIONS

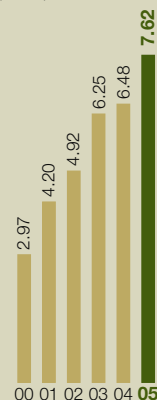
During the year, the Trust paid \$0.13 million for consulting fees to a company owned by the Chairman of the Board, \$0.04 million for vehicle leasing costs to a company associated with a member of the Board of Directors and \$0.12 million for legal fees to a law firm associated with a member of the Board of Directors. All amounts were based on normal commercial terms and conditions.

CONTRACTUAL OBLIGATIONS

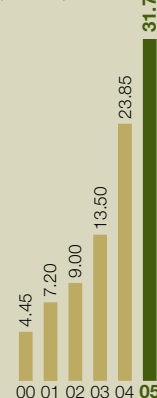
Zargon has certain contractual obligations relating to the lease of head office space, field operating leases and transportation contracts that extend for longer than one year as set out in the table below:

(\$ million)	Total	2006	2007 to 2008	2009 to 2010	Thereafter
Head office lease and other	1.16	0.71	0.44	0.01	–
Field operating leases	0.17	0.17	–	–	–
Transportation contracts	0.77	0.56	0.20	0.01	–
Total	2.10	1.44	0.64	0.02	–

Unitholders' Equity
(\$/unit)



Zargon Year End Trust Unit Price
(\$ million)



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.

MANAGEMENT AND FINANCIAL REPORTING SYSTEMS

EVALUATION OF DISCLOSURE CONTROL AND PROCEDURES

The Trust has established procedures and internal control systems to ensure timely and accurate preparation of financial, internal management and other reports. Disclosure controls and procedures are in place to ensure all ongoing statutory reporting requirements are met and material information is disclosed on a timely basis. The President and Chief Executive Officer and the Vice President, Finance and Chief Financial Officer, individually, sign certifications that the financial statements together with the other financial information included in the regulatory filings fairly present in all material respects the financial conditions, results of operation, and cash flows as of the dates and for the periods represented.

Our management, including our President and Chief Executive Officer and the Vice President, Finance and Chief Financial Officer, have evaluated the effectiveness of the Trust's disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, the President and Chief Executive Officer and the Vice President, Finance and Chief Financial Officer, have concluded that the Trust's disclosure controls are effective as of the end of the period covered by this annual report, in all material respects, after considering the Canadian Securities Administrator's Multilateral Instrument 52-109 "Certification of Disclosures in Issuers' Annual and Interim Filings."

BUSINESS RISKS AND OUTLOOK

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.

OUTLOOK

As a sustainable trust, Zargon is committed to maintaining reserves, production and distributions per unit in the context of distributing approximately 50 percent of its cash flow from operations to unitholders. For calendar 2006, Zargon has budgeted \$45 million of capital expenditures allocated to natural gas exploration and oil exploitation and is projecting an average production rate of approximately 8,600 barrels of oil equivalent per day. This amount does not include any allocation for opportunistic corporate or property acquisitions which, if available, would be funded by bank debt or equity issues.

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.

ADDITIONAL INFORMATION

Additional information regarding the Trust and its business operations, including the Trust’s Annual Information Form for December 31, 2005, is available on the Trust’s SEDAR profile at www.sedar.com.