MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") is a review of Zargon Energy Trust's 2006 financial results and should be read in conjunction with the audited consolidated financial statements and related notes for the years ended December 31, 2006 and 2005. 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 "funds flow from operations" ("funds 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 funds flow from operations may not be comparable to that reported by other trusts. The reconciliation between net earnings and funds 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 funds flow from operations. The Trust considers funds 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. Funds 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 funds 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 and liabilities.*
- *Operating netbacks equal total petroleum and natural gas revenue per boe adjusted for realized risk management gains and/or 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.*
- *Funds 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. Funds 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 12, 2007 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, except as required by law, 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 12, 2007.

2006 HIGHLIGHTS

The combination of high crude oil prices and stable production volumes enabled Zargon to achieve strong revenues and funds flow from operations in 2006, showing a slight decline of five percent and two percent, respectively, over the record-setting 2005 prior year results. The annual revenue decline came from a combination of factors, including a 19 percent decrease in natural gas prices received and a one percent decline in natural gas production. Both were substantially offset by an increase of oil and liquids prices received of seven percent and a three percent increase in oil and liquids production. Net earnings for the year were $44.50 million, a 26 percent increase from 2005. Earnings for 2006 were primarily supported by near record funds flow from operations of $83.52 million, a decrease of $1.45 million from 2005, and were further supported by unrealized risk management gains and a future income tax recovery.

Net capital expenditures for 2006 totalled $63.37 million with $66.51 million allocated to field-related activities and $3.14 million to net property disposals. Compared to the prior year, the 2006 capital program showed a 16 percent increase in overall net expenditures and a 27 percent increase in field-related expenditures. For the year ended December 31, 2006, Zargon spent $5.25 million to maintain an undeveloped land base of 381 thousand net acres (2005 – 367 thousand net acres); shot or acquired seismic at a cost of $3.34 million; drilled, equipped and tied-in wells for $57.92 million and generated net property dispositions of $3.14 million. The net property dispositions related primarily to the disposal of two non-core higher operating cost oil properties in the Williston Basin core area. No corporate acquisitions occurred in 2006. Cash distributions to unitholders totalled $35.90 million during the year (2005 – $37.44 million). All of these activities were funded by the funds flow received throughout the year plus an increase in debt net of working capital (excluding the unrealized risk management assets and liabilities) of $12.34 million.

Financial Highlights

($ million, except per unit amounts)	**2006**	2005	2004
Petroleum and natural gas revenue	**154.04**	162.72	123.97
Funds flow from operations	**83.52**	84.97	63.75
Per unit – diluted	**4.34**	4.51	3.40
Net earnings	**44.50**	35.37	20.63
Per unit – diluted	**2.68**	2.19	1.20
Total assets	**310.57**	277.86	226.96
Net capital expenditures [1]	**63.37**	54.68	56.27
Bank debt	**30.04**	10.34	14.23
Cash distributions	**35.90**	37.44	10.70

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

CASH DISTRIBUTIONS

Cash distributions to unitholders are at the discretion of the Board of Directors and can fluctuate depending on funds flow from operations. The Trust currently targets a payout ratio of approximately 50 percent of the funds flow attributed to unitholders. The Trust's capital program is financed from available funds flow and additional draw downs on the bank facilities if required. The key drivers of Zargon's funds flow are commodity prices and production volumes. Since the Trust's production is relatively evenly weighted between natural gas (2006 – 55 percent) and oil and liquids (2006 – 45 percent), both commodity prices have a significant effect on its funds flow. In the event that oil and natural gas prices and/or production volumes 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 volumes are lower than expected, the Trust may decrease distributions, increase debt and/or decrease the capital program. Zargon regularly reviews its monthly distribution policy in the context of the current commodity price environment, production levels and capital program requirements. Distributions remained constant throughout 2006 at $0.18 per trust unit and have been maintained at this level since November 2005. Cash distributions to unitholders declared for 2006 totalled $35.90 million, resulting in a payout ratio for the year of 43 percent of funds flow from operations or 50 percent on a per diluted trust unit basis.

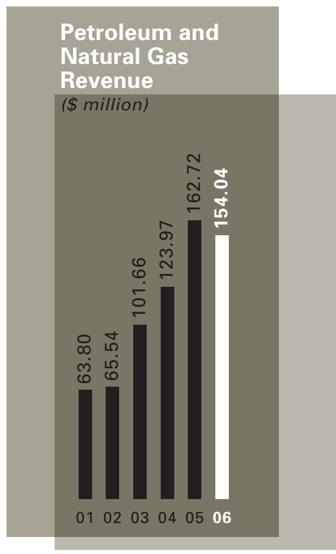
As part of its cash distribution policy, Zargon also considers on a semi-annual basis, the granting of supplemental distributions (over-and-above the monthly distribution). This decision is based on the commodity price environment, tax position, funding requirements for Zargon's exploration and development program and in the future will depend on further clarification of the impact of the recent federal government announcement regarding the taxation of income trusts. The Trust declared a supplemental distribution in December 2005 of $0.50 per trust unit but did not declare any supplemental distributions during 2006.

For Canadian income tax purposes, the 2006 cash distributions are 100 percent taxable income to unitholders.

DETAILED FINANCIAL ANALYSIS

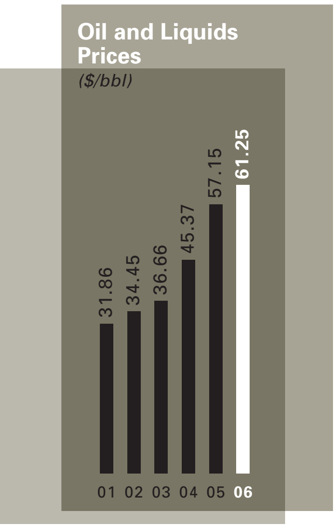
PETROLEUM AND NATURAL GAS REVENUE

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 the impact of financial risk management contracts, decreased five percent to $154.04 million in 2006 from $162.72 million in 2005 primarily due to significantly lower natural gas prices received which were mostly offset by higher oil and liquids prices and a slight increase in overall production. Compared to the prior year, the relative weighting of production revenue between petroleum and natural gas in 2006 was reallocated due to commodity pricing with 55 percent of the revenues coming from the sale of oil and liquids (47 percent in 2005) and 45 percent coming from the sale of natural gas (53 percent in 2005). Production volumes on a barrel of oil equivalent basis in 2006 increased one percent to 8,422 barrels of oil equivalent per day from the prior year amount of 8,342 barrels of oil equivalent per day. Specifically, in 2006 natural gas production decreased one percent and oil and liquids production increased three percent over 2005 levels. Production increases in oil and liquids resulted primarily from the effect of successful ongoing Williston Basin core area exploitation drilling programs. Natural gas production declines resulted from a combination of scheduled and unscheduled third party gas plant maintenance and unpredicted natural gas production declines. The average price of oil and liquids received by Zargon rose to $61.25 per barrel in 2006, up seven percent from 2005. The average field price of natural gas was $6.82 per thousand cubic feet in 2006, a 19 percent decrease over $8.41 per thousand cubic feet in 2005.



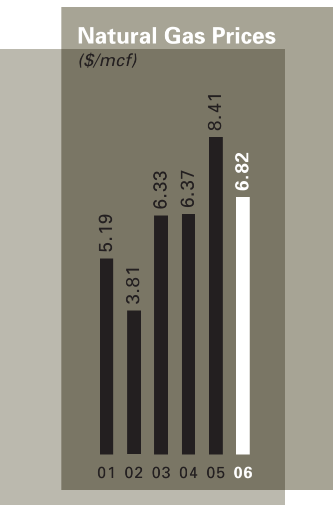
Pricing

Average for the year	**2006**	2005	2004
Natural Gas:			
NYMEX average daily spot price ($US/mmbtu)	**6.75**	8.89	5.90
AECO average daily spot price ($Cdn/mmbtu)	**6.54**	8.77	6.55
Zargon realized field price before the impact of financial risk management contracts ($Cdn/mcf)	**6.82**	8.41	6.37
Zargon realized field price before the impact of physical and financial risk management contracts ($Cdn/mcf)	**6.43**	8.49	6.31
Crude Oil:			
WTI ($US/bbl)	**66.22**	56.56	41.40
Edmonton par price ($Cdn/bbl)	**72.77**	68.72	52.54
Zargon realized field price before the impact of financial risk management contracts ($Cdn/bbl)	**61.25**	57.15	45.37



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 2006, Zargon's average oil and liquids field price, exclusive of the impact of financial risk management contracts, rose seven percent to $61.25 per barrel from $57.15 per barrel in 2005 and $45.37 per barrel in 2004. The field price differential for Zargon's average blended 30 degree API crude stream was $11.52 per barrel less than the 2006 Edmonton reference crude price, which compares to the 2005 differential of $11.57 per barrel and the 2004 differential of $7.17 per barrel. As the quality and weight of Zargon's crude stream have remained relatively consistent for several years, the movements in Zargon's price differential are 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 the impact of financial risk management contracts, for 2006 decreased to $6.82 per thousand cubic feet which is 19 percent lower than the 2005 average of $8.41 per thousand cubic feet, and seven percent higher than the 2004 average of $6.37 per thousand cubic feet. Historically, Zargon's field prices have shown a small discount to the benchmark AECO average daily price, due to a lower heating content for Zargon's natural gas and due to legacy aggregator and other contracts which are based partially on monthly index prices that tend to lag the AECO average daily index price in upward or downward trending markets. In 2006, as a result of downward trending natural gas markets, Zargon has realized a small non-recurring premium to the benchmark AECO average daily price due to a combination of fixed price physical contracts and the impact of Zargon receiving AECO monthly index pricing for a portion of its natural gas production. In 2006, the various fixed price physical contracts, which are treated as part of natural gas production revenue and natural gas pricing, created a gain of $2.51 million (2005 – $0.18 million), equivalent to an increase of $0.25 per thousand cubic feet (2005 – $0.02 per thousand cubic feet).

Similar to the prior year, approximately 24 percent of Zargon's 2006 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, which is approved by the Board of Directors, allows the use of forward sales and costless collars for a targeted range of 20 to 35 percent of oil and natural gas working interest production volumes, in order to partially offset the effects of large commodity price fluctuations. As both Canadian oil and natural gas field prices are closely correlated to US dollar denominated markets, Zargon will also enter into Cdn/US 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 funds 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 monitored these contracts in determining the continuation of hedge effectiveness. As at June 30, 2006, all designated hedge contracts had expired. For the designated hedge contracts, realized gains and losses were recorded in the statement of earnings as the contracts settled and no unrealized gain or loss was recognized.

For 2006, the total realized risk management loss was $0.57 million compared to a loss of $7.75 million in 2005 and a loss of $4.57 million in 2004. Of the 2006 loss, $4.45 million (equivalent to a reduction of $3.20 per barrel) is related to a loss from oil financial risk management transactions offset by $3.88 million (equivalent to an increase of $0.38 per thousand cubic feet) related to gains from natural gas financial 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 monthly pricing index. In 2006, NYMEX WTI crude oil prices generally increased throughout the first half of the year, peaking in the month of July. AECO natural gas prices trended downwards during the year. For financial risk management contracts entered into after December 31, 2004, the Trust considers 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 these contracts, an unrealized gain or loss is recorded based on the fair value (mark-to-market) of the contracts at year end. The 2006 net unrealized risk management gain totalled $9.55 million which compares to a $3.76 million net unrealized risk management loss in 2005 (2004 – nil). Specifically, the 2006 net unrealized risk management gains resulted from financial oil contract gains ($5.81 million) and financial natural gas contract gains ($3.74 million). These unrealized risk management gains or losses are generated by the change over the reporting period in the mark-to-market valuation of Zargon's future financial contracts. Gains or losses on fixed price physical contracts are included in petroleum and natural gas revenue when settled in the statement of earnings, and no mark-to-market valuation is recorded on these contracts.

As at December 31, 2006, the Trust had the following outstanding commodity price risk management contracts:

Financial Risk Management Contracts

	Rate	Weighted Average Price	Range of Terms
Oil swaps	500 bbl/d	$67.33 US/bbl	Jan. 1/07–Jun. 30/07
	500 bbl/d	$72.70 US/bbl	Jan. 1/07–Dec. 31/07
	500 bbl/d	$72.10 US/bbl	Jul. 1/07–Dec. 31/07
	300 bbl/d	$66.70 US/bbl	Jan. 1/08–Mar. 31/08
	300 bbl/d	$68.29 US/bbl	Apr. 1/08–Jun. 30/08
Natural gas swaps	3,000 gj/d	$9.13/gj	Jan. 1/07–Mar. 31/07
	4,000 gj/d	$8.47/gj	Apr. 1/07–Oct. 31/07
	1,000 gj/d	$8.77/gj	Nov. 1/07–Mar. 31/08
Natural gas collars	1,000 gj/d	$9.50/gj Put; $12.50/gj Call	Jan. 1/07–Mar. 31/07
	1,000 gj/d	$10.50/gj Put; $13.18/gj Call	Jan. 1/07–Mar. 31/07

Physical Risk Management Contracts

	Rate	Weighted Average Price	Range of Terms
Natural gas fixed price	2,000 gj/d	$9.23/gj	Jan. 1/07–Mar. 31/07
	1,000 gj/d	$7.88/gj	Apr. 1/07–Oct. 31/07
Natural gas collars	1,000 gj/d	$8.50/gj Put; $12.85/gj Call	Jan. 1/07–Mar. 31/07
	1,000 gj/d	$9.50/gj Put; $13.50/gj Call	Jan. 1/07–Mar. 31/07

ROYALTIES

Royalties include payments made to the Crown, freehold owners and third parties. Reported royalties also include the cost of the Saskatchewan Resource Surcharge (SRC), the cost of North Dakota state taxes and credits received through the Alberta Royalty Credit (ARC) program. During 2006, total royalties were $33.43 million, a decrease of 10 percent from $37.32 million in 2005. Royalties as a percentage of gross revenue were 21.7 percent in 2006 compared to 22.9 percent in 2005 and 22.6 percent in 2004. On a commodity basis, natural gas royalties averaged 20.8 percent in 2006, a decrease from the previous year's average of 23.3 percent. This decline is attributed to the effect of gains recognized on fixed price physical contracts and from the impact of Zargon receiving AECO monthly index pricing for a portion of its natural gas sales. Oil royalties averaged 22.4 percent, relatively unchanged from the prior year's rate of 22.5 percent, as was expected.

During 2006, 60 percent (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 2006, which is the same amount received in both 2005 and 2004. During the third quarter of 2006, the Alberta provincial government announced the elimination of the Alberta Royalty Credit effective January 1, 2007. The SRC charges were $1.01 million in 2006, relatively even with $1.03 million in the prior year and up from $0.64 million in 2004, reflecting the trend in Saskatchewan oil revenues. North Dakota state taxes increased to $2.27 million in 2006 from $1.82 million in the prior year, primarily due to increased prices for oil, as well as slightly increased production in the state.

PRODUCTION EXPENSES

Zargon's production expenses increased 10 percent to $26.42 million in 2006, from $24.04 million in 2005. On a unit of production basis, production expenses increased nine percent to $8.59 per barrel of oil equivalent from $7.89 in 2005 ($7.21 in 2004).

Natural gas production expenses in 2006 rose 11 percent to $1.05 per thousand cubic feet from $0.95 per thousand cubic feet in 2005. The primary reasons for the increase are due to increased gas gathering charges, increased rentals for compression equipment, increased water disposal and water hauling costs, all part of the industry-wide trend of higher operating costs.

Oil production expenses also rose in 2006 to $11.40 per barrel, an increase of seven percent from $10.64 per barrel in 2005. The primary reasons for the increase are due to increased costs industry-wide, particularly for electricity, propane and well servicing.

Due to the high levels of industry activity caused by the high commodity price environment, there was increasing upward pressure on per unit operating costs. In 2006, 2005 and 2004, Zargon's costs increased substantially due in general to the effect of industry-wide higher cost trends. This trend culminated with a $9.92 per barrel of oil equivalent operating cost in the fourth quarter of 2006, a level which included a prior period adjustment of $0.40 per barrel of oil equivalent relating primarily to third party natural gas processing costs. Going forward in 2007, Zargon is forecasting an average production expense of $9.25 per barrel of oil equivalent.

OPERATING NETBACKS

The average oil and liquids price received, after realized risk management losses, in 2006 of $58.05 per barrel was nine percent higher than the $53.32 per barrel received in 2005, while the average natural gas price received, after realized risk management gains/losses, in 2006 of $7.21 per thousand cubic feet was 12 percent below the $8.16 per thousand cubic feet received in 2005. Operating netbacks increased/decreased commensurately. Oil and natural gas liquids netbacks rose 11 percent to $32.93 per barrel from $29.80 per barrel in 2005. Natural gas netbacks decreased 10 percent to $4.73 per thousand cubic feet from $5.25 per thousand cubic feet in 2005. On a barrel of oil equivalent basis, 2006 operating netbacks declined one percent to $30.46 from $30.75 in 2005.

Operating Netbacks

	2006		2005	
	Oil and Liquids ($/bbl)	**Natural Gas ($/mcf)**	Oil and Liquids ($/bbl)	Natural Gas ($/mcf)
Production revenue	**61.25**	**6.82**	57.15	8.41
Realized risk management gain/(loss)	**(3.20)**	**0.38**	(3.83)	(0.25)
Royalties	**(13.72)**	**(1.42)**	(12.88)	(1.96)
Production costs	**(11.40)**	**(1.05)**	(10.64)	(0.95)
Operating netbacks	**32.93**	**4.73**	29.80	5.25

GENERAL AND ADMINISTRATIVE EXPENSES

Gross general and administrative costs increased 14 percent in 2006 to $10.25 million from $8.96 million in 2005. On a per unit of production basis, net general and administrative costs increased 14 percent to $2.27 per barrel of oil equivalent, compared to $1.99 per barrel of oil equivalent in 2005 and $1.45 in 2004. Trending upwards from 2004, the 2005 increased general and administrative costs on a per unit of production basis were due to increases in staff costs, performance-based compensation costs, regulatory reporting requirements and the additional legal and other outside advisory costs of operating as a trust. In 2006, the further increase on a per unit of production basis was impacted by additional office lease costs, and the costs related to the expansion of Zargon's technical staff.

General and Administrative Expenses

($ million, except as noted)	**2006**	2005	2004
Gross general and administrative expenses	**10.25**	8.96	7.23
Overhead recoveries	**(3.28)**	(2.91)	(2.87)
Net general and administrative expenses	**6.97**	6.05	4.36
Net expense after recoveries ($/boe)	**2.27**	1.99	1.45
Number of office employees at year end	**43**	39	35

INTEREST AND FINANCING CHARGES

Zargon's borrowings are through its syndicated bank credit facilities. Interest and financing charges were $1.53 million compared to $0.79 million in 2005. An increase in the average debt level and increases in borrowing rates are the primary reasons for the increase in interest and financing charges. Zargon's effective interest and financing charge rate was 6.4 percent on an average bank debt of $23.84 million in 2006, compared to 4.3 percent on an average bank debt of $18.17 million in 2005 and 4.9 percent on an average bank debt of $8.88 million in 2004. At year end 2006, Zargon's bank debt, net of working capital (excluding unrealized risk management assets and liabilities), totalled $39.83 million, up 45 percent from $27.49 million at December 31, 2005.

On June 30, 2006, Zargon amended and renewed its syndicated committed credit facilities, which resulted in an increase in the available facilities and borrowing base to $100 million from the previous amount of $80 million. The next renewal date is July 31, 2007.

CAPITAL AND CURRENT INCOME TAXES

Capital and current income taxes for 2006 were $1.60 million compared to $1.80 million in 2005. Of the total, $1.34 million is due to current taxes incurred in the United States compared to $0.90 million in 2005. The increased taxable income in the United States is due to declining tax pools and higher revenue in 2006 resulting in higher United States taxes. Provided that oil prices remain high, a similar level of United States current income taxes is predicted in 2007. The remaining current tax amounts relate to Canadian federal and provincial capital and withholding taxes, which were $0.26 million in 2006 compared to $0.90 million in 2005. This year-over-year decline was primarily the result of second quarter 2006 legislation substantively enacted by the Canadian Federal Government which eliminated the federal capital tax effective January 1, 2006. Tax pools as at December 31, 2006 were approximately $113 million which represents an increase from the comparable $90 million of tax pools available to Zargon at the end of 2005. The Trust is a taxable entity under the Income Tax Act (Canada) and currently is taxable only on the income that is not distributed or declared distributable to unitholders. For Canadian income tax purposes, 2006 distributions are 100 percent taxable income to unitholders.

On October 31, 2006, the Federal Government announced tax proposals pertaining to the taxation of distributions paid by trusts and the personal tax treatment of trust distributions. Currently, the Trust does not pay tax on distributions as tax is paid by the unitholders. If enacted, the proposals would result in taxation of distributions at the Trust level at a rate of 31.5 percent effective January 1, 2011. As the proposals are not yet enacted, there was no impact on the results of the Trust for the year ended December 31, 2006. The Trust is currently assessing the proposals and the potential implications to the Trust.

TRUST NETBACKS

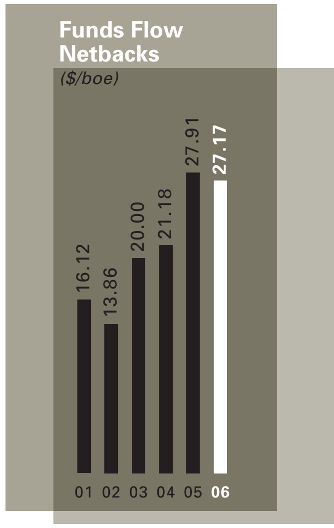
Historically high oil prices and the continued strength of natural gas prices in 2006 resulted in relatively strong revenue netbacks and operating netbacks. On a barrel of oil equivalent basis, revenue of $50.11 in 2006 was six percent lower than the prior year and operating netbacks as well as funds flow netbacks decreased one percent and three percent over the prior year to $30.46 and $27.17 per barrel of oil equivalent, respectively.

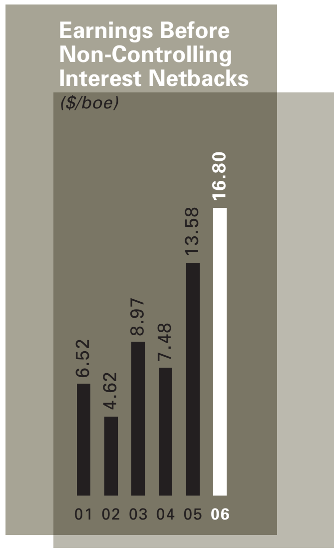
Trust Netbacks

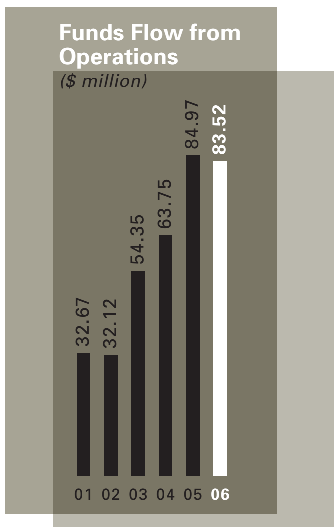
($/boe)	**2006**	2005	2004
Petroleum and natural gas revenue	**50.11**	53.44	41.20
Realized risk management loss	**(0.18)**	(2.55)	(1.52)
Royalties	**(10.88)**	(12.25)	(9.32)
Production costs	**(8.59)**	(7.89)	(7.21)
Operating netbacks	**30.46**	30.75	23.15
General and administrative	**(2.27)**	(1.99)	(1.45)
Interest and financing charges	**(0.50)**	(0.26)	(0.15)
Capital and current income taxes	**(0.52)**	(0.59)	(0.37)
Funds flow netbacks	**27.17**	27.91	21.18
Depletion and depreciation	**(13.38)**	(12.31)	(9.11)
Unrealized risk management gain/(loss)	**3.11**	(1.24)	–
Accretion of asset retirement obligations	**(0.41)**	(0.39)	(0.36)
Unit-based compensation	**(0.60)**	(0.30)	(1.22)
Unrealized foreign exchange gain/(loss)	**(0.01)**	0.07	0.19
Future income tax recovery/(expense)	**0.92**	(0.16)	(3.20)
Earnings before non-controlling interest	**16.80**	13.58	7.48

FUNDS FLOW FROM OPERATIONS *(see note at the beginning of the MD&A)*

In 2006, production volumes held steady, but the increase of seven percent in oil and natural gas liquids prices received was more than offset by a 19 percent decline in natural gas prices received, producing a two percent decline in funds flow from operations to $83.52 million, compared to $84.97 million in 2005 and $63.75 million in 2004. The corresponding funds flow per diluted unit was $4.34 in 2006, a four percent decline from $4.51 in 2005, and $3.40 in 2004. The diluted per unit statistics reflect a two percent increase in the weighted average outstanding units to 19.24 million in 2006, and a one percent increase in the average weighted number of outstanding units to 18.85 million in 2005 from 18.72 million in 2004.

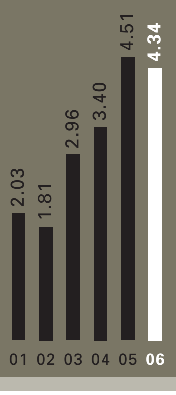






The following table summarizes the variances in funds flow from operations between 2005 and 2006. It shows that the variance is caused mainly by decreased commodity pricing, with partial offset coming from decreased royalties and lower realized risk management losses.

Funds Flow Per Unit
($/unit – diluted)



	$ Million	$ Per Diluted Trust Unit	Per Unit Percent Variance
Funds flow from operations - 2005	**84.97**	**4.51**	**–**
Price variance	(10.24)	(0.53)	(12)
Volume variance	1.56	0.08	2
Realized risk management losses	7.19	0.37	8
Royalties	3.89	0.20	5
Expenses:			
Production	(2.38)	(0.12)	(3)
General and administrative	(0.92)	(0.05)	(1)
Interest and financing charges	(0.75)	(0.04)	(1)
Current taxes	0.20	0.01	–
Weighted average trust units - diluted	–	(0.09)	(2)
Funds flow from operations - 2006	**83.52**	**4.34**	**(4)**

DEPLETION AND DEPRECIATION

In 2006, Zargon's depletion and depreciation provision increased 10 percent to $41.14 million, compared to $37.48 million in 2005 and $27.41 million in 2004. The higher charges reflect an increase of one percent in production volumes and a nine percent increase in the charge on a per barrel of oil equivalent basis. The primary reasons for the year-over-year expense increase on a per barrel of oil equivalent basis are due to the increase in the property and equipment balance from normal operations, from the impact of the conversion of exchangeable shares due to the application of EIC-151 and also as a result of second quarter 2006 and third quarter 2005 production losses and the related reserve adjustments due to the watering out of wells located at the Sturgeon Lake, Highvale, Judy Creek and Progress properties in the West Central Alberta core area.

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 2006 depletion calculation includes $14.11 million of future capital expenditures to develop the Trust's reserves, but excludes $20.99 million of unproven properties relating to undeveloped land.

Zargon's depletion and depreciation, on a barrel of oil equivalent basis, increased nine percent in 2006 to $13.38 from $12.31 in 2005 and $9.11 in 2004. 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 relatively higher commodity prices.

ACCRETION OF ASSET RETIREMENT OBLIGATIONS

For the year ended December 31, 2006, the non-cash accretion expense for asset retirement obligations is $1.24 million compared to $1.20 million in 2005 and $1.08 million in 2004. The year-over-year increases are due to changes in the estimated future liability for asset retirement obligations as a result of wells added through Zargon's drilling program. 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 occurring 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 $17.31 million as at December 31, 2006, based on a total future liability of $65.08 million.

UNIT-BASED COMPENSATION

Unit-based compensation was $1.86 million in 2006 or $0.96 million higher than the $0.90 million expense in 2005. The Trust generally grants unit rights on a quarterly basis. The increase in the expense is as a result of these new unit rights granted throughout 2006 and the vesting of unit rights previously granted. 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 employees and directors trust unit rights.

The trust unit rights incentive plan allows the Trust to issue rights to acquire trust units to directors, officers, employees and other 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

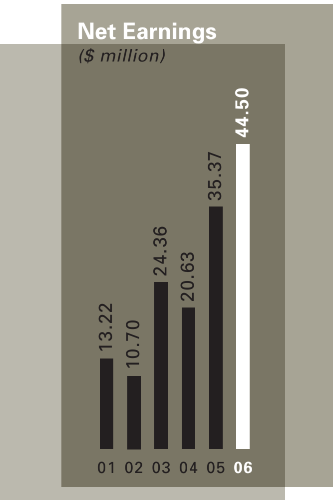
The provision for future tax recovery for 2006 was $2.82 million when compared to a future tax expense of $0.47 million in 2005 and an expense of $9.64 million in 2004. Effectively, Zargon's future tax obligations are reduced as distributions are made from the Trust and consequently it is anticipated that Zargon's effective tax rate will continue to be low. The 2006 year includes a second quarter recovery of $6.01 million relating to a reduction in future federal and provincial income tax rates substantively enacted during the 2006 second quarter and includes the impact of certain tax balance adjustments.

NON-CONTROLLING INTEREST–EXCHANGEABLE SHARES

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. Prior to 2005, these exchangeable shares were reflected as a component of unitholders' equity.

As a result of this 2005 change in accounting policy, the Trust has increased its unitholders' equity and non-controlling interest for 2006 by $12.12 million (2005 – $24.44 million) on the Trust's consolidated balance sheet. Consolidated net earnings for 2006 have been reduced for net earnings attributable to the non-controlling interest of $7.14 million (2005 – $5.99 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 2006 additionally resulted in an increase in property and equipment of $6.73 million (2005 – $24.93 million), and an increase in future income tax liability of $1.75 million (2005 – $6.48 million). Funds flow from operations were 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 $42.94 million, (for depletion impact see note 4 in the audited consolidated financial statements), unitholders' equity and non-controlling interest by $46.71 million, future income tax liability by $11.23 million and an allocation of net earnings to exchangeable shareholders of $15.00 million.

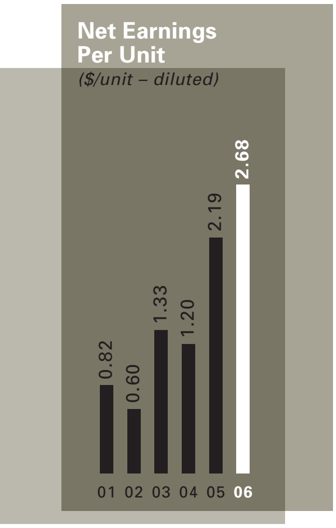


NET EARNINGS

Zargon's 2006 net earnings were $44.50 million, a $9.13 million increase from $35.37 million in 2005. The 2004 net earnings were $20.63 million. The net earnings track the funds flow from operations for the respective periods modified by non-cash charges, which in 2006 include depletion and depreciation, unrealized risk management gains, future income tax recoveries, unit-based compensation and non-controlling interest. On a per diluted unit basis, 2006 net earnings were $2.68 compared to $2.19 in 2005 and $1.20 in 2004.

On a barrel of oil equivalent basis, the 2006 earnings before non-controlling interest were $16.80 compared to $13.58 in 2005 and $7.48 in 2004.

The 2006 net earnings were 53 percent of funds flow from operations, primarily reflecting the increase in unrealized risk management gains and the reduction in future income taxes. The 2005 net earnings represented 42 percent of funds flow from operations compared to 32 percent of funds flow in 2004.



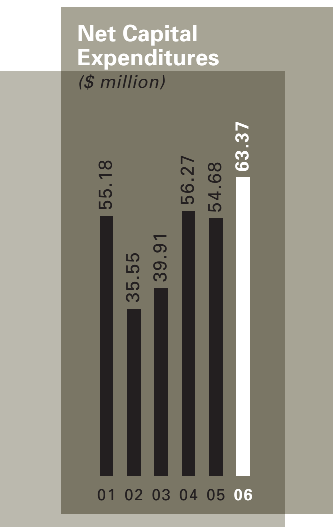
CAPITAL EXPENDITURES

Net capital expenditures in 2006 of $63.37 million increased 16 percent from $54.68 million in 2005. In 2006, Zargon completed an expanded drilling program of 89 gross (76.2 net) wells and drilling and completion expenditures climbed commensurately by 25 percent to $41.80 million. Of the total 2006 net capital expenditures, $18.29 million were expended on West Central Alberta, $22.95 million on Alberta Plains and $22.13 million on Williston Basin properties.

Capital Expenditures

($ million)	**2006**	2005	2004
Undeveloped land	**5.25**	3.65	3.84
Geological and geophysical (seismic)	**3.34**	3.47	5.26
Drilling and completion of wells	**41.80**	33.36	26.94
Well equipment and facilities	**16.12**	11.78	8.42
Exploration and development	**66.51**	52.26	44.46
Property acquisitions	**1.40**	3.68	12.09
Property dispositions	**(4.54)**	(2.45)	(0.28)
Net property acquisitions/(dispositions)	**(3.14)**	1.23	11.81
Corporate acquisitions assigned to property and equipment[1]	**–**	1.19	–
Total net capital expenditures[1]	**63.37**	54.68	56.27

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



LIQUIDITY AND CAPITAL RESOURCES

In 2006, the summation of the funds outflows pertaining to the net capital expenditure program ($63.37 million) and the cash distributions to unitholders ($35.90 million) exceeded by $11.73 million the summation of the funds inflows coming from the funds flow from operations ($83.52 million) plus the proceeds from the issuance of trust units ($4.02 million).

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

- Internally generated funds flow from operations 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 $100 million in syndicated committed credit facilities. As at December 31, 2006, $69.96 million or 70 percent of these facilities are unutilized.
- New equity, if available and if on favourable terms, can be utilized for acquisitions or to expand capital programs.

The recently announced changes to the Canadian income trust tax rules after 2010 may have negatively impacted the Canadian oil and gas trust industry's access to new capital from debt and equity markets in the future.

Capital Sources

($ million)	**2006**	2005	2004
Funds flow from operations	**83.52**	84.97	63.75
Change in bank debt	**19.70**	(3.89)	7.25
Issuance of trust units	**4.02**	3.87	2.87
Cash distributions to unitholders	**(35.90)**	(37.44)	(10.70)
Changes in working capital and other	**(7.97)**	7.17	2.54
Reorganization costs	**–**	–	(9.44)
Total capital sources	**63.37**	54.68	56.27

FUNDS FLOW FROM OPERATIONS

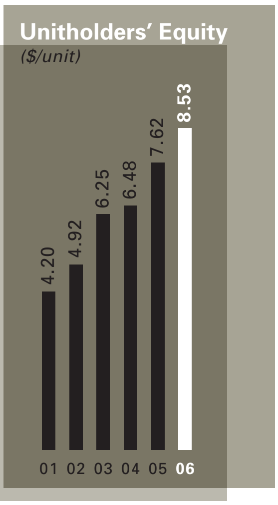
It is anticipated that Zargon's 2007 exploration and development capital budget and cash distributions to unitholders will be financed through the Trust's funds flow from operations. Funds flow is partially influenced by factors that the Trust cannot control, such as commodity prices, the US/Canadian dollar exchange rates and interest rates. Zargon's 2007 estimated sensitivity to moderate fluctuations in these key business parameters is shown in the accompanying table.

Funds Flow Sensitivity Summary

	Change in 2007 Funds Flow	
	($ million)	($/unit)
Change of $1.00 US/bbl in the price of WTI oil	0.80	0.04
Change in oil production of 100 bbl/d	0.92	0.05
Change of $0.10 US/mcf in the price of NYMEX natural gas	0.73	0.04
Change in natural gas production of one mmcf/d	1.49	0.08
Change in $0.01 in the $US/$Cdn exchange rate	1.32	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 replaced its former demand facility of $50 million. These facilities consisted of a $60 million tranche available to the Canadian borrower and a US $15 million tranche available to the US borrower. On June 30, 2006, Zargon amended and renewed these syndicated committed credit facilities, the result of which is an increase in the available facilities and borrowing base to $100 million from the previous amount of $80 million. These facilities consist of an $80 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 Zargon's management. The next renewal date is July 31, 2007. 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, these facilities have been classified as long term debt. At December 31, 2006, bank debt was $30.04 million, an increase of $19.70 million from the prior year end bank debt amount of $10.34 million.

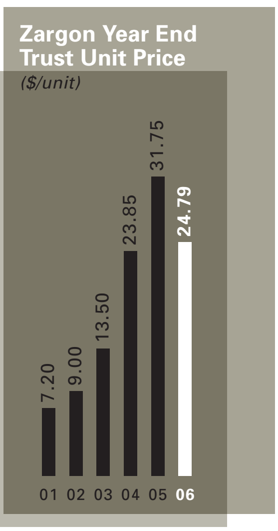


Zargon's debt net of working capital (excluding unrealized risk management assets and liabilities) of $39.83 million at December 31, 2006 was equivalent to 48 percent of the 2006 funds flow from operations of $83.52 million. At December 31, 2005, the debt net of working capital (excluding unrealized risk management assets and liabilities) was $27.49 million, equivalent to 32 percent of the 2005 funds flow from operations of $84.97 million.

EQUITY

At March 12, 2007, Zargon had 16.894 million trust units and 2.133 million exchangeable shares outstanding. Assuming full conversion of exchangeable shares at the effective exchange ratio of 1.21149, there would be 19.478 million trust units outstanding at this date. Pursuant to the trust unit rights incentive plan, there are currently an additional 1.311 million trust unit incentive rights issued and outstanding.

During 2006, 10.80 million Zargon trust units traded on The Toronto Stock Exchange with a high trading price of $34.75 per unit, a low of $24.10 per unit and a closing price of $24.79 per unit. The 2006 trading statistics show an 18 percent year-over-year decrease in trading volume, and a 22 percent decrease in the closing unit price. Zargon's market capitalization (including the market value of exchangeable shares) at year end 2006 was approximately $482 million, compared to approximately $603 million at the end of 2005.



SEGMENTED GEOGRAPHIC INFORMATION

In calendar 2006, approximately 84 percent (2005 – 87 percent) of Zargon's combined petroleum and natural gas revenue came from Western Canadian (Alberta, Saskatchewan and Manitoba) properties, with the remaining 16 percent (2005 – 13 percent) of revenues generated in the United States (North Dakota).

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, 2006.

RELATED PARTY TRANSACTIONS

During the year, the Trust paid $0.05 million (2005 – $0.04 million) for vehicle leases to a company owned by a Board member; $0.09 million (2005 – $0.12 million) for legal services to a law firm in which a Board member is a partner; $0.02 million (2005 – $0.01 million) for field services to a company of which a senior Zargon officer is a Board member and nominal shareholder; and $0.06 million (2005 – $0.13 million) in consulting fees to a company owned by the Chairman of the Board. 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	2007	2008 to 2009	2010 to 2011	Thereafter
Head office lease and other	6.73	1.16	2.45	2.42	0.70
Field operating leases	0.04	0.04	-	-	-
Transportation contracts	0.92	0.73	0.19	-	-
Total	7.69	1.93	2.64	2.42	0.70

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 flow from production of proved reserves. Accordingly, the Trust must base this calculation of future net cash flow 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 flow from proved and probable reserves using future price forecasts and costs discounted at a risk-free rate.

ASSET RETIREMENT OBLIGATIONS

Zargon follows 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

As of January 1, 2007, the Trust is required to adopt CICA Section 1530 *"Comprehensive Income"*, Section 3251 *"Equity"*, Section 3855 *"Financial Instruments–Recognition and Measurement"*, and Section 3865 *"Hedges"*, which were issued in January 2005. Under the new standards, a new financial statement, the Consolidated Statement of Comprehensive Income, has been introduced that will provide for certain gains and losses and other amounts arising from changes in fair value, to be temporarily recorded outside the income statements. In addition, all financial instruments, including derivatives, are to be included in the Trust's Consolidated Balance Sheets and measured, in most cases, at fair values, and requirements for hedge accounting have been further clarified. The Trust is currently evaluating the impact of the new standards. Management does not anticipate the new and revised standards will have a material impact on its consolidated financial statements as the Trust currently uses fair value accounting for derivative instruments that do not qualify or are not designated as hedges.

As of January 1, 2007, the Trust is required to adopt revised CICA Section 1506, *"Accounting Changes"*, which provides expanded disclosures for changes in accounting policies, accounting estimates and corrections of errors, which were issued in July 2006. Under the new standard, accounting changes should be applied retrospectively unless otherwise permitted or where impracticable to determine. As well, voluntary changes in accounting policy are made only when required by a primary source of GAAP or when the change results in more relevant and reliable information. The Trust does not expect application of this revised standard to have a material impact on its consolidated financial statements.

MANAGEMENT AND FINANCIAL REPORTING SYSTEMS

DESIGN OF INTERNAL CONTROL OVER FINANCIAL REPORTING AND EVALUATION OF DISCLOSURE CONTROL AND PROCEDURES

The Trust has designed internal controls over financial reporting and 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 Executive Vice President 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 operations and cash flows as of the dates and for the periods represented.

Our management, including our President and Chief Executive Officer and the Executive Vice President and Chief Financial Officer, have designed internal controls over financial reporting and have evaluated the effectiveness of the Trust's disclosure controls and procedures as at the end of the period covered by this report. Based on the above, the President and Chief Executive Officer and the Executive Vice President and Chief Financial Officer, have concluded that the Trust has designed internal controls over financial reporting and the Trust's disclosure controls are effective as at 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."

Because of their inherent limitations, disclosure controls and procedures and internal controls over financial reporting may not prevent or detect misstatements, errors or fraud. Control systems, no matter how well conceived or operated, can provide only reasonable, not absolute assurance that the objectives of the control systems are met.

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 could 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 on the Trust's financial and operating results.

Financial and liquidity risks are reduced by limiting debt financing to self-imposed debt to funds flow guidelines. Zargon maintains a low cash distribution to funds 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.

The recently announced changes to the Canadian income trust tax rules after 2010 may have negatively impacted the Canadian oil and gas trust industry's access to new capital from debt and equity markets in the future.

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 trust unit in the context of distributing approximately 50 percent of its funds flow from operations to unitholders. For calendar 2007, Zargon has budgeted $55 million of capital expenditures allocated to natural gas exploration and oil exploitation and is projecting an average production rate of approximately 8,750 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 issuances.

SELECTED QUARTERLY INFORMATION

	2006				2005			
($ million, except per unit amounts)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Petroleum and natural gas revenue	**36.50**	**37.93**	**38.66**	**40.94**	50.26	42.47	35.87	34.12
Funds flow from operations	**19.01**	**20.04**	**22.13**	**22.35**	26.62	21.85	19.01	17.48
Per unit – diluted	**0.98**	**1.03**	**1.14**	**1.17**	1.40	1.15	1.01	0.93
Net earnings	**7.05**	**12.31**	**13.22**	**11.92**	17.45	6.30	6.48	5.14
Per unit – diluted	**0.43**	**0.73**	**0.79**	**0.72**	1.06	0.39	0.41	0.32
Cash distributions	**9.05**	**9.00**	**8.96**	**8.89**	16.66	7.45	6.73	6.60
Per trust unit	**0.54**	**0.54**	**0.54**	**0.54**	1.02	0.46	0.42	0.42
Net capital expenditures (1)	**20.41**	**18.99**	**8.78**	**15.19**	19.12	13.91	10.96	10.69
Total assets	**310.57**	**294.14**	**283.86**	**282.35**	277.86	264.44	253.75	245.20
Bank debt	**30.04**	**20.71**	**18.14**	**26.64**	10.34	11.43	15.52	18.23

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

FOURTH QUARTER 2006 RESULTS

During the fourth quarter of 2006, Zargon's petroleum and natural gas revenues of $36.50 million were four percent lower than the previous quarter's revenues. Production for the 2006 fourth quarter of 8,366 barrels of oil equivalent per day fell short of the fourth quarter guidance of 8,500 barrels of oil equivalent per day by two percent and was two percent higher than the 2006 third quarter's production of 8,194 barrels of oil equivalent per day. Compared to the previous quarter, oil production increased two percent to 3,789 barrels per day as Williston Basin horizontal wells were placed on production. Fourth quarter natural gas production increased two percent over the previous quarter to 27.46 million cubic feet per day as recently drilled West Central Alberta and Alberta Plains natural gas wells were tied-in. Average field prices received during the fourth quarter, before the impact of financial risk management contracts, were $54.69 per barrel for oil and liquids and $6.90 per thousand cubic feet for natural gas, a 19 percent reduction and a 15 percent increase, respectively, compared to the 2006 third quarter prices. Reflecting market and seasonal trends, Zargon's field price differential for its blended 30 degree API crude oil stream decreased to a $9.80 per barrel discount to the Edmonton reference crude oil price, a 19 percent decrease from Zargon's average differential of $12.09 per barrel for the first nine months of 2006.

Funds flow from operations was $19.01 million in the fourth quarter, a decrease of five percent or $1.03 million over the prior quarter. A comparative analysis of the primary factors that caused this quarter-over-quarter decrease is as follows:

- Realized risk management gains increased by $0.82 million to $1.16 million, a 244 percent increase over the prior quarter's $0.34 million of risk management gains. The primary reason for this increase in the fourth quarter related to gains on financial natural gas risk management contracts due to the lower natural gas prices received throughout the quarter.
- Royalties for the fourth quarter were $7.84 million, a decrease of $0.64 million from the prior quarter. The average royalty rate for the quarter declined to 21.5 percent from 22.3 percent from the third quarter. This decline is attributed to the effect of fourth quarter gains recognized on fixed price physical natural gas contracts which increase natural gas pricing and revenue.
- Production expenses increased to $7.64 million for the quarter, a $0.66 million or nine percent increase from the third quarter of 2006. On a per barrel of oil equivalent basis, production expenses increased seven percent to $9.92 in the fourth quarter of 2006 compared to $9.26 in the prior quarter. The quarterly increase in per unit costs reflected the impact of prior period natural gas processing adjustments, well servicing, water hauling and repairs and maintenance costs.
- General and administrative expenses increased slightly in the fourth quarter by $0.09 million over the third quarter of 2006. This is a five 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 $0.47 million, an increase of 26 percent or $0.10 million from the prior quarter. The average debt level for the fourth quarter increased 28 percent to $27.51 million compared to $21.49 million in the third quarter of 2006, resulting in increased debt servicing charges.
- Capital and current income taxes increased by $0.21 million from the third quarter of 2006. The increase was primarily due to Canadian withholding taxes and an increase in United States current income taxes.

Net earnings for the quarter decreased $5.26 million to $7.05 million, a 43 percent decrease compared to the third quarter 2006 net earnings of $12.31 million. Net earnings track the funds flow from operations for the respective periods modified by non-cash charges, which included the following for the fourth quarter of 2006:

- Unit-based compensation expense increased by $0.07 million during the fourth quarter of 2006 to $0.62 million, a 13 percent increase over the third quarter. The increase is a result of additional unit rights granted in the fourth quarter of 2006.
- Depletion and depreciation expense increased by $0.70 million to $10.86 million in the fourth quarter. The additional expense resulted from the use of an updated depletion and depreciation rate of $14.11 per barrel of oil equivalent, compared to the prior quarter's $13.48 per barrel of oil equivalent charge. The increased per unit charges are calculated on the basis of the recently completed 2006 year end reserve appraisal prepared by independent engineers that reflects Zargon's and the ongoing industry's trend to higher finding and development costs. Furthermore, 2006 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.
- Unrealized risk management gains in the 2006 fourth quarter of $0.80 million were 87 percent lower than the third quarter gains of $6.27 million. These unrealized gains result from "marking-to-market" financial risk management contracts at each period end. During the fourth quarter, unrealized risk management gains resulted from weaker commodity pricing at the December 31, 2006 mark-to-market date when compared to the third quarter September 30, 2006 mark-to-market date. In particular, lower year end futures oil pricing resulted in unrealized contract gains of $1.89 million, offset by natural gas losses of $1.09 million due to the realization and the expiry of certain financial natural gas contracts.
- Future income tax recovery was $0.79 million during the quarter, compared to a future income tax expense of $1.17 million from the third quarter of 2006. The future income tax recovery in the 2006 fourth quarter was due to the significant decrease of earnings before taxes to $8.22 million from the third quarter earnings before taxes of $15.73 million. Summarized, the fourth quarter decrease in net earnings was primarily derived by the decrease of non-cash unrealized risk management contract gains and increased field costs.
- Reduction in earnings due to non-controlling interests pertaining to exchangeable shares decreased to $1.30 million in the 2006 fourth quarter, from $1.80 million in the third quarter. This was due to a decrease in net earnings before non-controlling interest in the fourth quarter.

Net capital expenditures were $20.41 million during the fourth quarter of 2006, a seven percent increase from the prior quarter amount of $18.99 million. During the fourth quarter, Zargon completed an extensive field capital program focused on Alberta Plains core area natural gas well down-spacing and step-out drilling program and a Williston Basin core area horizontal oil well program. During the fourth quarter of 2006, 33.4 net wells were drilled, compared to 19.9 net wells in the third quarter of 2006.

Cash distributions to unitholders declared for the quarter totalled $9.05 million, resulting in a quarterly payout ratio of 48 percent of funds flow from operations or 55 percent on a per diluted trust unit basis.

ADDITIONAL INFORMATION

Additional information regarding the Trust and its business operations, including the Trust's Annual Information Form for December 31, 2006, is available on the Trust's SEDAR profile at www.sedar.com.