ZARGON

OIL & GAS LTD.

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March 13, 2007

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

Dear Sir or Madame:

SUPPL

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

Pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 194, as amended, enclosed is a copy of the Company's news release dated March 13, 2007. As required pursuant to Rule 12g3-2(b), the exemption number appears in the upper right-hand corner of each unbound page and of the first page of each bound document.

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

Yours truly,
ZARGON ENERGY TRUST

BC Heagy

B.C. Heagy
Executive Vice President & CFO

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FOR IMMEDIATE RELEASE: March 13, 2007
TSX SYMBOLS: ZAR.UN; ZOG.B

ZARGON ENERGY TRUST ANNOUNCES 2006 FOURTH QUARTER AND FULL YEAR RESULTS

Zargon Energy Trust ("Zargon" or the "Trust") today announced its operating and financial results for the fourth quarter and year ended December 31, 2006.

Highlights from the fourth quarter and year ended December 31, 2006:

- Fourth quarter 2006 revenue of $36.50 million, funds flow from operations of $19.01 million and net earnings of $7.05 million were four percent, five percent and 43 percent, respectively, lower than the preceding 2006 third quarter levels. Revenue for the full year decreased by five percent to $154.04 million, funds flow from operations decreased two percent to $83.52 million and net earnings increased 26 percent to $44.50 million.

- Production volumes in 2006 remained relatively stable with a year-over-year increase of one percent to 8,422 barrels of oil equivalent per day compared to 2005. Fourth quarter production of 27.46 million cubic feet per day of natural gas and 3,789 barrels per day of oil and liquids provided Zargon quarterly production volumes of 8,366 barrels of oil equivalent per day, two percent higher than third quarter volumes. On a per unit basis, Zargon's 2006 production averaged 437 barrels of oil equivalent per day per million trust units which represented a two percent decrease from the prior year's average rate.

- Net capital expenditures in 2006 were $63.37 million with $3.14 million of net property dispositions and $66.51 million for exploration and development programs. For the year, Zargon drilled a record 76.2 net wells with a 95 percent success ratio, yielding 47.7 net gas wells, 22.5 net oil wells, 4.0 net dry holes and 2.0 net service wells.

- The 2006 capital program replaced, on a proved and probable basis, 122 percent of Zargon's 2006 production volumes. Year end proved and probable reserves increased three percent to 27.46 million barrels of oil equivalent. Zargon's 2006 proved and probable finding, development and acquisition costs (excluding future development costs) were $16.85 per barrel of oil equivalent. The three-year average proved and probable finding, development and acquisition costs (excluding future development costs) were $14.72 per barrel of oil equivalent. At December 31, 2006, Zargon's proved and probable reserves remained constant at 1.41 barrels of oil equivalent per total unit. In a previous press release dated February 21, 2007, Zargon provided details of 2006 year end reserves.

- Cash distributions in 2006 of $2.16 per trust unit were declared and represented 50 percent of the year's $4.34 per diluted trust unit of funds flow from operations. Including the effect of the exchangeable shares, which do not receive distributions, the 2006 cash distributions totalled $35.90 million or 43 percent of the year's $83.52 million of funds flow from operations. Fourth quarter cash distributions totalled $0.54 per trust unit.

- Year end debt net of working capital (excluding unrealized risk management assets and liabilities) of $39.83 million is slightly more than 0.5 times annualized fourth quarter funds flow from operations.

	Three Months Ended December 31, 2006	2005	Percent Change	Year Ended December 31, 2006	2005	Percent Change
	(unaudited)	(unaudited)				
FINANCIAL HIGHLIGHTS						
Income and Investments ($ million)						
Petroleum and natural gas revenue	**36.50**	50.26	(27)	**154.04**	162.72	(5)
Funds flow from operations	**19.01**	26.62	(29)	**83.52**	84.97	(2)
Cash distributions	**9.05**	16.66	(46)	**35.90**	37.44	(4)
Net earnings	**7.05**	17.45	(60)	**44.50**	35.37	26
Net capital expenditures	**20.41**	19.12	7	**63.37**	54.68	16
Per Unit, Diluted						
Funds flow from operations ($/unit)	**0.98**	1.40	(30)	**4.34**	4.51	(4)
Net earnings ($/unit)	**0.43**	1.06	(59)	**2.68**	2.19	22
Cash Distributions ($/trust unit)	**0.54**	1.02	(47)	**2.16**	2.32	(7)
Balance Sheet at Year End ($ million)						
Property and equipment, net				**283.11**	253.32	12
Bank debt				**30.04**	10.34	191
Unitholders' equity				**165.56**	144.61	14
Total Units Outstanding at Year End (million)				**19.42**	18.99	2
OPERATING HIGHLIGHTS						
Average Daily Production						
Oil and liquids (bbl/d)	**3,789**	4,030	(6)	**3,805**	3,697	3
Natural gas (mmcf/d)	**27.46**	27.73	(1)	**27.70**	27.87	(1)
Equivalent (boe/d)	**8,366**	8,651	(3)	**8,422**	8,342	1
Equivalent per million trust units (boe/d)	**431**	457	(6)	**437**	445	(2)
Average Selling Price (before the impact of financial risk management contracts)						
Oil and liquids ($/bbl)	**54.69**	57.58	(5)	**61.25**	57.15	7
Natural gas ($/mcf)	**6.90**	11.34	(39)	**6.82**	8.41	(19)
Wells Drilled, Net	**33.4**	15.3	118	**76.2**	53.5	42
Undeveloped Land at Year End (thousand net acres)				**381**	367	4

Notes:

- *Throughout this press release, the calculation of barrels of oil equivalent (boe) is based on the conversion ratio that six thousand cubic feet of natural gas is equivalent to one barrel of oil.*
- *For net capital expenditures, amounts include capital expenditures acquired for cash and equity issuances.*
- *Total units outstanding include trust units plus exchangeable shares outstanding at year end. The exchangeable shares are converted at the exchange ratio at the end of the year.*
- *Funds flow from operations is a non-GAAP term that represents net earnings except for non-cash items.*
- *Average daily production per million trust units is calculated using the weighted average number of units outstanding during the period, plus the weighted average number of exchangeable shares outstanding for the period converted at the average exchange ratio for the period.*

FOURTH QUARTER 2006 CAPITAL PROGRAM*

Exploration and development fourth quarter capital expenditures of $20.29 million were mostly allocated to a very active 39 gross (33.4 net) well drilling program that resulted in 30 gross (26.1 net) gas wells and nine gross (7.3 net) oil wells. Of the natural gas wells, 25 were drilled in our Alberta Plains core area, two wells were drilled in Highvale and one each in the Hamelin Creek, Progress and Saddle Hills properties of the West Central Alberta core area. The remaining nine oil wells were all drilled in the Williston Basin core area and included six horizontal wells in the Steelman and Elswick properties of Saskatchewan and the Haas, North Dakota property.

Zargon increased production by two percent in the fourth quarter of 2006 compared to the previous quarter as a result of the tie-in of natural gas wells from the multi-well program at Jarrow and new oil wells at Steelman and Pinto in the Williston Basin core area. Continued tie-in of wells from the multi-well program in the Jarrow and Hamilton Lake properties of the Alberta Plains core area as well as new volumes from the tie-in of successful wells from the West Central Alberta core area drilling program are expected to provide gains in natural gas production in the first quarter of 2007.

GUIDANCE*

In a press release dated February 21, 2007, Zargon provided production guidance for the first quarter of 2007 of 8,500 barrels of oil equivalent per day and also reconfirmed annual production guidance of the Trust at 8,750 barrels of oil equivalent per day based on a $55 million 2007 capital program. As of the date of this press release, this guidance remains unchanged.

Throughout 2006, Zargon maintained its monthly base cash distribution at $0.18 per trust unit which was based on Zargon's sustainable trust strategy that targets for the distribution of approximately 50 percent of the Trust's funds flow from operations attributed to the unitholders. In 2007, Zargon plans to continue with its base (sustainable) monthly cash distribution of $0.18 per trust unit which is premised on the current 2007 production guidance levels, positive contributions from the current risk management contracts and the long term commodity price assumptions of US $55 per barrel (WTI oil), a US $7.50 per mmbtu (NYMEX natural gas) price and an $0.87 Cdn/US dollar currency exchange rate.

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

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.

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

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.

	$ 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 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).

SELECTED QUARTERLY INFORMATION

($ million, except per unit amounts)	2006				2005			
	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.

ZARGON ENERGY TRUST

CONSOLIDATED BALANCE SHEETS

As at December 31 ($ thousand)	**2006**	2005
ASSETS *[note 5]*		
Current		
Accounts receivable *[note 11]*	**18,362**	21,835
Prepaid expenses and deposits	**3,281**	2,710
Unrealized risk management asset *[note 11]*	**5,817**	-
	27,460	24,545
Property and equipment, net *[notes 3 and 4]*	**283,108**	253,315
	310,568	277,860
LIABILITIES		
Current		
Accounts payable and accrued liabilities	**28,410**	30,570
Cash distributions payable *[note 17]*	**3,022**	11,122
Unrealized risk management liability *[note 11]*	**20**	3,756
	31,452	45,448
Long term debt *[note 5]*	**30,037**	10,339
Asset retirement obligations *[note 6]*	**17,307**	15,859
Future income taxes *[note 9]*	**47,891**	48,928
	126,687	120,574
Commitments and contingencies *[notes 11, 12 and 13]*		
NON-CONTROLLING INTEREST		
Exchangeable shares *[note 8]*	**18,319**	12,673
UNITHOLDERS' EQUITY		
Unitholders' capital *[note 7]*	**82,868**	71,644
Contributed surplus *[note 7]*	**2,475**	1,347
Accumulated earnings	**164,267**	119,768
Accumulated cash distributions *[note 17]*	**(84,048)**	(48,146)
	165,562	144,613
	310,568	277,860

See accompanying notes to the consolidated financial statements.

ZARGON ENERGY TRUST

CONSOLIDATED STATEMENTS OF EARNINGS AND ACCUMULATED EARNINGS

For the years ended December 31 ($ thousand, except per unit amounts)	2006	2005
Revenue		
Petroleum and natural gas revenue	154,039	162,722
Unrealized risk management gain/(loss) *[note 11]*	9,553	(3,756)
Realized risk management loss	(569)	(7,754)
Royalties	(33,431)	(37,319)
	129,592	113,893
Expenses		
Production	26,416	24,035
General and administrative *[note 18]*	6,973	6,053
Unit-based compensation *[note 7]*	1,856	902
Interest and financing charges *[note 5]*	1,532	786
Unrealized foreign exchange (gain)/loss	24	(201)
Accretion of asset retirement obligations *[note 6]*	1,244	1,196
Depletion and depreciation	41,136	37,484
	79,181	70,255
Earnings before income taxes	50,411	43,638
Income taxes *[note 9]*		
Current	1,598	1,801
Future (recovery)	(2,824)	474
	(1,226)	2,275
Earnings for the year before non-controlling interest	51,637	41,363
Non-controlling interest – exchangeable shares *[note 8]*	(7,138)	(5,994)
Net earnings for the year	44,499	35,369
Accumulated earnings, beginning of year	119,768	84,399
Accumulated earnings, end of year	164,267	119,768
Net earnings per unit *[note 10]*		
Basic	2.68	2.21
Diluted	2.68	2.19

See accompanying notes to the consolidated financial statements.

ZARGON ENERGY TRUST

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ thousand)	**2006**	2005
Operating activities		
Net earnings for the year	**44,499**	35,369
Add (deduct) non-cash items:		
Non-controlling interest – exchangeable shares	**7,138**	5,994
Unrealized risk management (gain)/loss	**(9,553)**	3,756
Depletion and depreciation	**41,136**	37,484
Accretion of asset retirement obligations	**1,244**	1,196
Unit-based compensation	**1,856**	902
Unrealized foreign exchange (gain)/loss	**24**	(201)
Future income taxes (recovery)	**(2,824)**	474
	83,520	84,974
Asset retirement expenditures	**(627)**	(604)
Changes in non-cash working capital *[note 14]*	**842**	(1,401)
	83,735	82,969
Financing activities		
Advances (repayment) of bank debt	**19,698**	(3,891)
Cash distributions to unitholders	**(35,902)**	(37,444)
Exercise of unit rights	**4,018**	2,723
Changes in non-cash working capital *[note 14]*	**(8,099)**	8,974
	(20,285)	(29,638)
Investing activities		
Additions to property and equipment	**(67,909)**	(55,986)
Proceeds on disposal of property and equipment	**4,543**	2,446
Changes in non-cash working capital *[note 14]*	**(84)**	209
	(63,450)	(53,331)
Change in cash, and cash end of year	**-**	-

See supplementary information contained in note 15.

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
For the years ended December 31, 2006 and 2005.
All amounts are stated in Canadian dollars unless otherwise stated.

1. STRUCTURE OF THE TRUST

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

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation and Basis of Presentation

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

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

Revenue Recognition

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

Joint Operations

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

Property and Equipment

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

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

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

Impairment Test

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

Asset Retirement Obligations

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

Financial Instruments

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

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

For financial risk management contracts entered into prior to December 31, 2004, the Trust's policy was to designate each derivative financial instrument employed as a hedge of a specific portion of projected production over the term of the instrument. The Trust formally documented its risk management objectives and strategies for undertaking the hedged transactions, the hedging item, the nature of the specific risk exposures being hedged, the intended term of the hedge relationship, the method for assessing effectiveness and the method of accounting for the hedging relationship. The effectiveness of the derivative was assessed on an ongoing basis to ensure that the derivatives entered into were highly effective in offsetting changes in fair values of the hedged items. The instruments employed could have been denominated in US or Canadian dollars. Gains or losses from all hedging contracts, other than forward sales settled by physical delivery, were recognized as hedging gains or losses when the sale of hedged production occurred. The Trust believed these derivative financial instruments used were effective as hedges over their term. In the event that a designated hedged item ceased to exist, any realized or unrealized gain or loss on such derivative commodity instruments were to be recognized in income immediately. If the hedge relationship was terminated, either via ineffectiveness or via termination of the designation, gains or losses previously deferred continued to be deferred and recognized when they were realized. As at June 30, 2006, all designated hedge contracts had expired.

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

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

Foreign currency swap agreements may be used from time to time to manage the risk inherent in producing commodities whose price is based directly or indirectly on US dollars, using a notional principal amount equal to the projected monthly revenue from their sale. Payments or charges are calculated and paid according to the terms of the agreement, usually with monthly settlement. At December 31, 2006 and 2005 the Trust had no such financial instruments.

Income Taxes

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

Foreign Currency Translation

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

Trust Unit Rights and Unit-Based Compensation

Under the Trust's unit rights incentive plan (the "Plan"), rights to purchase trust units are granted to directors, officers and employees at current market prices. The Plan allows for the exercise price of rights to be reduced in future periods by an amount that distributions exceed a stated return on assets. Under the fair value method of accounting for unit-based compensation the cost of the option is charged to earnings with an offsetting amount recorded to contributed surplus, based on an estimate of the fair value using a Black-Scholes option-pricing model. Forfeiture of rights are recorded as a reduction in expense in the period in which they occur.

Per Unit Amounts

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

Measurement Uncertainty

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

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

Cash Distributions

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

3. ACQUISITION

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

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

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

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

4. PROPERTY AND EQUIPMENT

	December 31, 2006		
($ thousand)	**Cost**	**Accumulated Depletion and Depreciation**	**Net Book Value**
Petroleum, natural gas properties and equipment*	**457,865**	**175,585**	**282,280**
Office equipment	**1,841**	**1,013**	**828**
	459,706	**176,598**	**283,108**

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

**As a result of shareholders redeeming exchangeable shares, property and equipment has cumulatively increased $42.94 million, $6.73 million relating to 2006, $24.93 million relating to 2005 and $11.28 million relating to 2004. The effect of these increases has resulted in additional depletion and depreciation expense of approximately $10.56 million, $5.48 million relating to 2006 and $5.08 million relating to 2005.*

At December 31, 2006, petroleum, natural gas properties and equipment include $20.99 million (2005 – $14.72 million) relating to undeveloped properties that have been excluded from the depletion calculation.

An impairment test calculation was performed on the Trust's petroleum, natural gas properties and equipment at December 31, 2006 in which the estimated undiscounted future net cash flows associated with the proved reserves exceeded the carrying amount of the Trust's petroleum, natural gas properties and equipment. This impairment calculation was performed separately on both the Canadian and US cost centres.

The following table outlines benchmark prices used in the impairment test at December 31, 2006:

Year	WTI Crude Oil ($US/bbl)	Exchange Rate ($US/$Cdn)	WTI Crude Oil ($Cdn/bbl)	AECO Gas ($Cdn/gj)
2007	66.26	0.88	75.30	6.65
2008	68.20	0.88	77.50	7.71
2009	67.06	0.88	76.21	7.67
2010	65.44	0.88	74.36	7.37
2011	65.08	0.88	73.95	7.07
Thereafter (inflation %)	2.0%	0.88	2.0%	2.0%

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

5. LONG TERM DEBT

On September 30, 2005, a Canadian subsidiary and a US subsidiary of the Trust entered into syndicated committed credit facilities with a borrowing base of $80 million which 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. Interest rates fluctuate under the syndicated facilities with Canadian prime, US prime, and US base rates plus an applicable margin between zero basis points and 25 basis points, as well as with Canadian banker's acceptance and LIBOR rates plus an applicable margin between 90 basis points and 150 basis points. At December 31, 2006, $30.04 million (2005 – $10.34 million) had been drawn on the syndicated committed credit facilities bearing interest at Canadian prime (December 31, 2006 – 6.0 percent; December 31, 2005 – 5.0 percent) with any unused amounts subject to standby fees. In the normal course of operations Zargon enters into various letters of credit. At December 31, 2006, the approximate value of outstanding letters of credit totalled $0.47 million (2005 – $0.47 million).

6. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligation was estimated by management based on Zargon's net working interest in all wells and facilities, estimated costs to reclaim and abandon wells and facilities and the estimated timing of the costs to be incurred in future periods. Zargon has estimated the net present value of its total asset retirement obligations to be $17.31 million as at December 31, 2006 (2005 – $15.86 million), based on a total future liability of $65.08 million (2005 – $62.54 million). These payments are expected to be made over the next 30 years with the majority of the costs being incurred after 2012. Commencing July 1, 2005, incremental asset retirement obligations are calculated using a revised credit adjusted risk-free rate of 7.5 percent. Asset retirement obligations prior to this period were calculated using a credit adjusted risk-free rate of 8.5 percent. An inflation rate of two percent used in the calculation of the present value of the asset retirement obligation remains unchanged. The following table reconciles Zargon's asset retirement obligations:

	Year Ended December 31,	
($ thousand)	**2006**	2005
Balance, beginning of year	**15,859**	14,390
Net liabilities incurred	**826**	906
Liabilities settled	**(627)**	(604)
Accretion expense	**1,244**	1,196
Foreign exchange	**5**	(29)
Balance, end of year	**17,307**	15,859

7. UNITHOLDERS' EQUITY

Pursuant to the Plan of Arrangement on July 15, 2004, 14.87 million units of the Trust and 3.66 million exchangeable shares (see note 8) of the Company were issued in exchange for all of the outstanding shares of the Company on a one-for-one basis.

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

Trust Units

	December 31, 2006		December 31, 2005	
(thousand)	**Number of Units**	**Amount ($)**	Number of Units	Amount ($)
Balance, beginning of year	**16,355**	**71,644**	15,341	45,755
Unit rights exercised for cash	**208**	**4,018**	153	2,723
Unit-based compensation recognized on exercise of unit rights	**-**	**728**	-	725
Issued on conversion of exchangeable shares	**226**	**6,478**	821	21,297
Issued on corporate acquisition *(note 3)*	**-**	**-**	40	1,144
Balance, end of year	**16,789**	**82,868**	16,355	71,644

Trust Unit Rights Incentive Plan

The Trust has a unit rights incentive plan (the "Plan") that allows the Trust to issue rights to acquire trust units to directors, officers, employees and 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 at any time exceed 10 percent of the aggregate number of issued and outstanding trust units of the Trust. At the time of grant, unit right exercise prices approximate the market price for the trust units. At the time of exercise, the rights holder has the option of exercising at the original grant price or the exercise price as calculated per the Arrangement. Rights granted under the Plan generally vest over a three-year period and expire approximately five years from the grant date. Zargon uses a fair value methodology to value the unit rights grants.

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

	December 31, 2006		December 31, 2005	
	Number of Unit Rights (thousand)	**Weighted Average Exercise Price ($/unit right)**	Number of Unit Rights (thousand)	Weighted Average Exercise Price ($/unit right)
Outstanding at beginning of year	**915**	**22.80**	579	17.79
Unit rights granted	**518**	**29.70**	505	26.89
Unit rights exercised	**(208)**	**19.30**	(153)	17.77
Unit rights cancelled	**(17)**	**25.59**	(16)	18.13
Outstanding at end of year	**1,208**	**26.32**	915	22.80
Unit rights exercisable at year end	**212**	**24.11**	48	17.70

The following table summarizes information about unit rights outstanding at December 31, 2006:

	Unit Rights Outstanding			**Unit Rights Exercisable**	
Range of Exercise Prices ($/unit right)	**Number Outstanding at 12/31/06 (thousand)**	**Weighted Average Remaining Contractual Life**	**Weighted Average Exercise Price ($/unit right)**	**Number Exercisable at 12/31/06 (thousand)**	**Weighted Average Exercise Price ($/unit right)**
17.70 – 19.25	239	**2.1 years**	17.77	**70**	**17.70**
22.00 – 25.06	281	**3.6 years**	23.45	**42**	**22.10**
27.40 – 29.93	272	**3.5 years**	28.55	**45**	**27.40**
31.09 – 33.05	416	**3.7 years**	31.74	**55**	**31.09**
	1,208		26.32	**212**	**24.11**

Unit-Based Compensation

The weighted average assumptions made for unit rights granted for 2006 include a volatility factor of expected market price of 26.6 percent, a risk-free interest rate of 4.1 percent, a dividend yield of 7.4 percent and an expected life of the unit rights of four years. These unit rights, together with the continued vesting of unit rights granted in prior years resulted in unit-based compensation expense in 2006 of $1.86 million (2005 – $0.90 million).

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

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

Contributed Surplus

($ thousand)	
Balance, December 31, 2004	1,170
Unit-based compensation expense	902
Unit-based compensation recognized on exercise of unit rights	(725)
Balance, December 31, 2005	**1,347**
Unit-based compensation expense	**1,856**
Unit-based compensation recognized on exercise of unit rights	**(728)**
Balance, December 31, 2006	**2,475**

Unit Redemption

Under the terms of the Trust Indenture, unitholders may require the Trust to redeem all or any part of the trust units at a price and under certain terms and conditions as specified in the Trust Indenture. The redemption price per trust unit will be equal to the lesser of: (i) 90 percent of the "market price" of the trust units on the principal market on which the trust units are quoted for trading during the 10 trading day period commencing immediately after the date on which the trust units are tendered to Zargon for redemption; and (ii) the closing market price on the principal market on which the trust units are quoted for trading on the date that the trust units are so tendered for redemption. Trust units tendered for redemption in any calendar month shall be paid on the last day of the third following month by, at the Trust's option: (i) a cash payment; or (ii) a distribution of notes and/or redemption notes. It is anticipated that this redemption right will not be the primary mechanism for holders of trust units to dispose of their trust units. Notes or redemption notes which may be distributed in specie to unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop for such notes or redemption notes. Notes or redemption notes may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans. To date, no trust units have been tendered for redemption.

8. NON-CONTROLLING INTEREST – EXCHANGEABLE SHARES

Zargon Oil & Gas Ltd. is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares are convertible into trust units at the option of the shareholder, based on the exchange ratio, which is adjusted monthly to reflect the distribution paid on the trust units. Cash distributions are not paid on the exchangeable shares. During the year, a total of 0.20 million (2005 – 0.78 million) exchangeable shares were converted into 0.23 million (2005 – 0.82 million) trust units based on the exchange ratio at the time of conversion. At December 31, 2006, the exchange ratio was 1.19403 (December 31, 2005 – 1.09629) trust units per exchangeable share. As set out in the Arrangement, the exchangeable shares are entitled to vote equally to the number of trust units for which each exchangeable share is convertible into a trust unit on the record date. The Board of Directors of Zargon Oil & Gas Ltd. hold the option to redeem all outstanding exchangeable shares for trust units on or before July 15, 2014. At such time, should the Board not extend the term of the shares, there would be no remaining non-controlling interest.

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

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

Non-Controlling Interest – Exchangeable Shares

(thousand, except exchange ratio)	December 31, 2006 Number of Shares	December 31, 2006 Amount ($)	December 31, 2005 Number of Shares	December 31, 2005 Amount ($)
Balance, beginning of year	**2,402**	**12,673**	3,186	9,529
Exchanged for trust units at book value and including earnings attributed since Plan of Arrangement	**(195)**	**(1,492)**	(784)	(2,850)
Earnings attributable to non-controlling interest	**-**	**7,138**	-	5,994
Balance, end of year	**2,207**	**18,319**	2,402	12,673
Exchange ratio, end of year	**1.19403**		1.09629	
Trust units issuable upon conversion of exchangeable shares, end of year	**2,635**		2,633	

The proforma total units outstanding at December 31, 2006, including trust units outstanding, and trust units issuable upon conversion of exchangeable shares and after giving rise to the exchange ratio at the end of the year is 19.42 million units (2005 – 18.99 million units).

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

($ thousand)	**Zargon Energy Trust Units**	**Zargon Oil & Gas Ltd. Exchangeable Shares**	**Total**
Balance at December 31, 2004	45,755	9,529	55,284
Issued on redemption of exchangeable shares at book value	1,909	(1,909)	-
Effect of EIC-151	19,388	5,053	24,441
Unit-based compensation recognized on exercise of unit rights	725	-	725
Unit rights exercised for cash	2,723	-	2,723
Issued on corporate acquisition	1,144	-	1,144
Balance at December 31, 2005	**71,644**	**12,673**	**84,317**
Issued on redemption of exchangeable shares at book value	**477**	**(477)**	**-**
Effect of EIC-151	**6,001**	**6,123**	**12,124**
Unit-based compensation recognized on exercise of unit rights	**728**	**-**	**728**
Unit rights exercised for cash	**4,018**	**-**	**4,018**
Balance at December 31, 2006	**82,868**	**18,319**	**101,187**

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 sheets 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 EIC-151, 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), 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.

9. INCOME TAXES

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. As the Trust allocates all of its Canadian taxable income to the unitholders in accordance with the Trust Indenture, and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no current tax provision for Canadian income tax expense has been made in the Trust. Canadian large corporation tax, capital taxes, and US income taxes are provided for under current income tax expense.

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

On October 31, 2006, the Federal Government announced tax proposals pertaining to 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.

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

($ thousand)	2006	2005
Statutory income tax rate	**36.30%**	38.86%
Expected income taxes	**18,300**	16,958
Add (deduct) income tax effect of:		
Non-deductible Crown charges, net of Alberta Royalty Credit	**2,145**	5,058
Resource allowance	**(2,397)**	(5,062)
Rate adjustment	**(8,865)**	(1,674)
Cash distributions	**(13,032)**	(14,551)
Large corporation tax, capital taxes, and US income taxes	**1,598**	1,801
Other	**1,025**	(255)
	(1,226)	2,275

The future income tax provision for the year ended December 31, 2006 includes a recovery of $6.01 million relating to a reduction in future federal and provincial income tax rates substantively enacted and recorded during the 2006 second quarter. The Federal Government budget also eliminated the Canadian large corporation tax effective January 1, 2006.

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

($ thousand)	2006	2005
Net book value of property and equipment in excess of tax pools	**46,336**	46,088
Deferred partnership earnings	**6,024**	10,178
Asset retirement obligations	**(6,333)**	(5,631)
Unrealized risk management asset/liability	**2,104**	(1,319)
Share issue costs	**(8)**	(19)
Alberta Royalty Credit	**(232)**	(369)
	47,891	48,928

As at December 31, 2006, Zargon's tax pools are as follows:

($ thousand)	December 31, 2006
Canadian oil and gas property expenses in the Trust	**41,947**
Canadian oil and gas property expenses in other entities	**5,892**
Canadian development expenses	**24,681**
Canadian exploration expenses	**23,488**
Capital cost allowance	**30,161**
US tax pools	**4,555**
Partnership deferral	**(18,190)**
Other	**269**
	112,803

10. WEIGHTED AVERAGE NUMBER OF TOTAL UNITS

(thousand units)	2006	2005
Basic	**16,600**	16,003
Diluted	**19,244**	18,848

Dilution amounts of 2.64 million units (2005 – 2.85 million) were added to the weighted average number of units outstanding during the year in the calculation of diluted per unit amounts. These unit additions represent the dilutive effect of unit rights according to the treasury stock method, and also include exchangeable shares using the "if-converted" method. An adjustment to the numerator amount was required in the diluted calculation to provide for the earnings of $7.14 million (2005 – $5.99 million) attributable to the non-controlling interest pertaining to the exchangeable shareholders.

11. FINANCIAL INSTRUMENTS

Fair Value of Financial Assets and Liabilities

Financial instruments of the Trust consist of accounts receivable, deposits, accounts payable, cash distributions payable, unrealized risk management assets and liabilities and long term debt. As at December 31, 2006 and 2005, there are no significant differences between the carrying values of these amounts and their estimated market values.

Credit Risk Management

Accounts receivable include amounts receivable for petroleum and natural gas sales that are generally made to large credit-worthy purchasers, and amounts receivable from joint venture partners that are recoverable from production. Accordingly, management views credit risks on these amounts as low. Of Zargon's significant individual accounts receivable at December 31, 2006, approximately 26 percent was owing from one company (2005 – 32 percent).

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

Interest Rate Risk Management

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

Foreign Currency Risk Management

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

Commodity Price Risk Management

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

The Trust has outstanding contracts at December 31, 2006 as follows:

Financial Contracts at December 31, 2006:	**Rate**	**Weighted Average Price**	**Range of Terms**	**Fair Market Value Gain/(Loss) ($ thousand)**
Oil swaps	500 bbl/d	$67.33 US/bbl	Jan. 1/07–Jun. 30/07	393
	500 bbl/d	$72.70 US/bbl	Jan. 1/07–Dec. 31/07	1,641
	500 bbl/d	$72.10 US/bbl	Jul. 1/07–Dec. 31/07	609
	300 bbl/d	$66.70 US/bbl	Jan. 1/08–Mar. 31/08	(20)
	300 bbl/d	$68.29 US/bbl	Apr. 1/08–Jun. 30/08	30
Natural gas swaps	3,000 gj/d	$9.13/gj	Jan. 1/07–Mar. 31/07	729
	4,000 gj/d	$8.47/gj	Apr. 1/07–Oct. 31/07	1,676
	1,000 gj/d	$8.77/gj	Nov. 1/07–Mar. 31/08	97
Natural gas collars	1,000 gj/d	$9.50/gj Put $12.50/gj Call	Jan. 1/07–Mar. 31/07	276
	1,000 gj/d	$10.50/gj Put $13.18/gj Call	Jan. 1/07–Mar. 31/07	366
Net Fair Market Value, Financial Contracts				**5,797**

Physical Contracts at December 31, 2006:

	Rate	Weighted Average Price	Range of Terms	Fair Market Value Gain/(Loss) ($ thousand)
Natural gas fixed price	2,000 gj/d	$9.23/gj	Jan. 1/07–Mar. 31/07	503
	1,000 gj/d	$7.88/gj	Apr. 1/07–Oct. 31/07	293
Natural gas collars	1,000 gj/d	$8.50/gj Put $12.85/gj Call	Jan. 1/07–Mar. 31/07	186
	1,000 gj/d	$9.50/gj Put $13.50/gj Call	Jan. 1/07–Mar. 31/07	276
Total Fair Market Value, Physical Contracts				**1,258**

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

For financial risk management contracts, 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 any unrealized gains or losses are recorded based on the fair value (mark-to-market) of the contracts at the period end. The unrealized gain for 2006 was $9.55 million and the unrealized loss for 2005 was $3.76 million.

Contracts settled by way of physical delivery are recognized as part of the normal revenue stream. These instruments have no book values recorded in the consolidated financial statements.

12. COMMITMENTS

The Trust is committed to future minimum payments for natural gas transportation contracts in addition to operating leases for office space, office equipment, vehicles and field equipment. Payments required under these commitments for each of the next five years are: 2007 – $1.93 million; 2008 – $1.39 million; 2009 – $1.25 million; 2010 – $1.21 million; 2011 – $1.21 million; thereafter – $0.70 million.

13. CONTINGENCIES AND GUARANTEES

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

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

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

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

14. CHANGES IN NON-CASH WORKING CAPITAL

	Year Ended December 31,	
($ thousand)	**2006**	2005
Changes in non-cash working capital items:		
Accounts receivable	**3,473**	(7,560)
Prepaid expenses and deposits	**(571)**	243
Accounts payable and accrued liabilities	**(2,160)**	6,417
Cash distributions payable	**(8,100)**	8,912
Other	**17**	(230)
	(7,341)	7,782
Changes relating to operating activities	**842**	(1,401)
Changes relating to financing activities	**(8,099)**	8,974
Changes relating to investing activities	**(84)**	209
	(7,341)	7,782

15. SUPPLEMENTAL CASH FLOW INFORMATION

($ thousand)	**2006**	2005
Cash interest and financing charges paid	**1,593**	1,044
Cash taxes paid	**2,216**	1,911

16. SEGMENTED INFORMATION

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

		2006	
($ thousand)	**Canada**	**United States**	**Combined**
Petroleum and natural gas revenue	**129,967**	**24,072**	**154,039**
Earnings before income taxes	**39,797**	**10,614**	**50,411**
Property and equipment, net	**248,440**	**34,668**	**283,108**
Total assets	**273,748**	**36,820**	**310,568**
Net capital expenditures	**58,040**	**5,326**	**63,366**

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

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

17. CASH DISTRIBUTIONS

During the year, the Trust declared distributions to the unitholders in the aggregate amount of $35.90 million (2005 – $37.44 million) in accordance with the following schedule:

2006 Distributions	**Record Date**	**Distribution Date**	**Per Trust Unit**
January	January 31, 2006	February 15, 2006	$0.18
February	February 28, 2006	March 15, 2006	$0.18
March	March 31, 2006	April 17, 2006	$0.18
April	April 30, 2006	May 15, 2006	$0.18
May	May 31, 2006	June 15, 2006	$0.18
June	June 30, 2006	July 17, 2006	$0.18
July	July 31, 2006	August 15, 2006	$0.18
August	August 31, 2006	September 15, 2006	$0.18
September	September 30, 2006	October 16, 2006	$0.18
October	October 31, 2006	November 15, 2006	$0.18
November	November 30, 2006	December 15, 2006	$0.18
December	December 31, 2006	January 15, 2007	$0.18

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

18. RELATED PARTY TRANSACTIONS

Zargon 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. These payments were in the normal course of operations, on commercial terms, and therefore were recorded at the exchange amount.

Forward-Looking Statements - This document contains statements that are forward-looking, such as those relating to results of operations and financial condition, capital spending, financing sources, commodity prices, costs of production and the magnitude of oil and natural gas reserves. By their nature, forward-looking statements are subject to numerous risks and uncertainties that could significantly affect anticipated results in the future and, accordingly, actual results may differ materially from those predicted. The forward-looking statements contained in this press release are as of March 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.

Based in Calgary, Alberta, Zargon is a sustainable energy trust with oil and natural gas operations in Alberta, Saskatchewan, Manitoba and North Dakota. Zargon's securities trade on the Toronto Stock Exchange.

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

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