



Q2

2007 Second Quarter Report

Financial and Operating Highlights

	Three months ended June 30, 2007	Three months ended June 30, 2006	Six months ended June 30, 2007	Six months ended June 30, 2006
Financial (\$000)				
Revenue before royalties	\$ 125,075	\$ 80,766	\$ 260,577	\$ 167,667
per Trust Unit ⁽¹⁾	\$ 1.10	\$ 1.29	\$ 2.35	\$ 2.76
per boe	\$ 50.69	\$ 48.48	\$ 51.31	\$ 51.42
Funds from operations	\$ 62,634	\$ 42,281	\$ 128,279	\$ 88,911
per Trust Unit ⁽²⁾	\$ 0.54	\$ 0.62	\$ 1.13	\$ 1.41
per boe	\$ 25.38	\$ 25.39	\$ 25.26	\$ 27.27
Net income	\$ 4,531	\$ 23,905	\$ 4,872	\$ 39,869
per Trust Unit ⁽¹⁾	\$ 0.04	\$ 0.38	\$ 0.04	\$ 0.66
Distributions declared	\$ 52,096	\$ 53,498	\$ 102,302	\$ 97,957
per Trust Unit ⁽²⁾	\$ 0.45	\$ 0.75	\$ 0.90	\$ 1.50
Payout ratio (%)	83%	127%	80%	110%
Expenditures on property and equipment	\$ 25,678	\$ 27,782	\$ 75,374	\$ 48,771
Working capital deficit ⁽³⁾	\$ 11,512	\$ 13,774	\$ 11,512	\$ 13,774
Bank indebtedness	\$ 377,812	\$ 500,837	\$ 377,812	\$ 500,837
Convertible debentures (face value)	\$ 180,725	\$ 180,795	\$ 180,725	\$ 180,795
Operating				
Daily Production				
Natural gas (mcf/d)	108,978	70,293	111,636	68,043
Crude oil and NGLs (bbls/d)	8,952	6,593	9,452	6,676
Total boe/d @ 6:1	27,115	18,309	28,058	18,017
Average prices (including hedging)				
Natural gas (\$/mcf)	\$ 7.52	\$ 6.18	\$ 7.80	\$ 7.39
Crude oil and NGLs (\$/bbl)	\$ 61.93	\$ 68.69	\$ 60.21	\$ 63.44
Supplemental (\$000)				
Trust Units outstanding at end of period	116,091	94,689	116,091	94,689
Trust Units issuable				
Convertible Debentures	8,334	8,339	8,334	8,339
Trust Units Rights Incentive Plan	150	273	150	273
Trust Units outstanding and issuable at end of period	124,575	103,301	124,575	103,301
Basic weighted average Trust Units	113,854	62,710	111,108	60,803

⁽¹⁾ based on basic weighted average Trust Units outstanding⁽²⁾ based on Trust Units outstanding at each distribution record date⁽³⁾ working capital deficit excludes derivative assets and liabilities

MESSAGE TO UNITHOLDERS

Highlights for the second quarter 2007 include:

- Production volumes in the second quarter of 2007 increased 48% to 27,115 boe/d compared to 18,309 boe/d in the second quarter of 2006. Production volumes in the second quarter of 2007 are higher due to volumes from the Ketch acquisition, which closed June 23, 2006.
- Natural gas production for the second quarter of 2007 increased 55% to 109.0 mmcf/d compared to 70.3 mmcf/d reported in the second quarter of 2006. Crude oil and natural gas liquids production increased 36% to 8,952 bbls/d compared to 6,593 bbls/d in the second quarter of 2006.
- Q2 2007 payout ratio decreased to 83% compared to 127% for the same period in 2006. The decreased payout ratio is a result of previous distribution adjustments and Q2 2006 including only eight days of Ketch cash flows in funds from operations while a full month of distributions were paid on the corresponding Trust Units issued for the acquisition. Our year to date payout ratio is 80% for the six months ended June 30, 2007, which is on-track with expectations and results from our hedging gains and solid operational performance.
- The Fund declared three distributions during the quarter totaling \$0.45 per Trust Unit. Since inception, the Fund has distributed \$766.9 million or \$15.39 per Trust Unit.
- Funds from operations for the second quarter of 2007 was \$62.6 million or \$0.54 per Trust Unit compared to \$42.3 million or \$0.62 per Trust Unit for the same period of 2006.
- Capital spending during Q2 2007 included the drilling of 5.8 net (10 gross) wells at a 100% success rate. Drilling activity in the current quarter amounted to \$8 million and \$10 million was directed to complete facilities work and well completions resulting from our highly successful Q1 2007 program. Additionally, \$7 million was spent on land, seismic and other non-operated activities for total exploitation and development capital of \$25.7 million in the quarter. Success continued in our light oil program at Nevis, Southeast Saskatchewan and Sunset and with our gas drilling at Northville and Willesden Green.
- Per unit operating costs in Q2 2007 have decreased by 6% to \$10.91/boe when compared to Q1 2007. Q1 costs were higher than normal due to winter freezing conditions that created significant one-time expenditures. Total operating costs have decreased by 11% from Q1 2007 and we are actively pursuing optimization opportunities to improve the cost structure.

Hedging Position

- Advantage has layered in several hedges on both natural gas and oil which will provide floor protection through summer 2007 and winter 2007/2008 for natural gas.
- Given current weakness in natural gas prices, Advantage is well positioned through Q3 & Q4 2007. The Fund currently has approximately 54% of our net natural gas production hedged for summer at an average floor price of \$7.08 /mcf and an average ceiling of \$8.09/mcf. In addition, 14% of our net crude oil production has been hedged for the same period at an average floor of US\$65.00/bbl and a ceiling of US\$90.00/bbl.
- For the winter months and extending into the spring of 2008, Advantage has 28% of our net natural gas production hedged at a floor price of \$8.85/mcf and a ceiling of \$10.19/mcf.
- Advantage has been opportunistic with respect to hedging and will continue to monitor the forward prices to protect cash flow.

Looking Forward

- We are reiterating our guidance range of 27,500 to 29,500 boe/d for 2007. We expect to trend towards the lower end of this range due to delays created by the extremely wet weather conditions experienced this spring and the continuing third party outages that will occur this summer.
- Operating costs are expected to be approximately \$10.50 to \$11.50 on a per boe basis due to reduced production through the Q2 and Q3 periods. However, total operating costs have decreased by 11% in Q2 when compared to Q1 2007. Reduced industry drilling activity in the last half of 2007 may have a cascade effect of reducing service & related costs.
- Royalty rates are expected to remain in the 19 to 20% range for 2007.
- Capital spending will be directed toward more oil projects in the second half of 2007 due to continued higher crude oil pricing. Total exploration and development capital for 2007 is expected to be unchanged at \$125 to \$145 million. Advantage's highly attractive and large drilling inventory allows flexibility in our capital allocation.
- Advantage has exceptional tax pool coverage which will help reduce the amount of tax leakage to Unitholders for several years after 2011. As of December 31, 2006, the Fund had approximately \$1.2 billion in tax pools which was one of the highest in the sector as a percentage of market capitalization.

Proposed Business Combination with Sound Energy Trust:

- On July 9, 2007, Advantage and Sound Energy Trust ("Sound") announced that their respective boards of directors had unanimously approved an agreement for the business combination of Advantage and Sound. The combined trust, which will retain the Advantage name and management, will have an initial enterprise value of approximately \$2.5 billion. The combination will be accomplished through a Plan of Arrangement (the "Arrangement") by the exchange of each Sound Trust Unit for 0.30 of an Advantage Trust Unit or, at the election of the holder of Sound Trust Units, \$0.66 in cash and 0.2557 of an Advantage Trust Unit. In addition, all Sound Exchangeable Shares will be exchanged for Advantage Trust Units on the same ratio based on the conversion ratio in effect at the effective date of the Arrangement. The Arrangement is expected to close in early September 2007.
- The key benefits of the transaction are:
 - Highly accretive on a production, cash flow, reserves and net asset value per Trust Unit basis;
 - Improvement in Advantage's payout ratio;
 - The Sound assets have a high degree of operating synergies with key Advantage properties through facilities optimization opportunities and by significantly increasing the number of low risk drilling locations. In addition, the net undeveloped land inventory increases 111% to 760,000 net acres;
 - Advantage's tax pools will increase 35% to over \$1.6 billion which will be one of the highest in the sector relative to market capitalization;
 - Sound's hedging program complements Advantage's hedging program. Sound has 55% of their net natural gas production hedged at a floor price of \$7.91/mcf for Q4 2007; and
 - The combined entity is estimated to have 2007 exit rate production of approximately 35,000 to 36,500 boe/d and a proved plus probable reserve life index of approximately 11.8 years using 2007 estimated exit rate production.

MANAGEMENT'S DISCUSSION & ANALYSIS

The following Management's Discussion and Analysis ("MD&A"), dated as of August 14, 2007, provides a detailed explanation of the financial and operating results of Advantage Energy Income Fund ("Advantage", the "Fund", "us", "we" or "our") for the three and six months ended June 30, 2007 and should be read in conjunction with the consolidated financial statements contained within this interim report and the audited financial statements and MD&A for the year ended December 31, 2006. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and all references are to Canadian dollars unless otherwise indicated. All per barrel of oil equivalent ("boe") amounts are stated at a conversion rate of six thousand cubic feet of natural gas being equal to one barrel of oil or liquids.

Non-GAAP Measures

The Fund discloses several financial measures in the MD&A that do not have any standardized meaning prescribed under GAAP. These financial measures include funds from operations and per Trust Unit, cash netbacks, and payout ratio. Management believes that these financial measures are useful supplemental information to analyze operating performance, leverage and provide an indication of the results generated by the Fund's principal business activities prior to the consideration of how those activities are financed or how the results are taxed. Investors should be cautioned that these measures should not be construed as an alternative to net income, cash provided by operating activities or other measures of financial performance as determined in accordance with GAAP. Advantage's method of calculating these measures may differ from other companies, and accordingly, they may not be comparable to similar measures used by other companies.

Funds from operations, as presented, is based on cash provided by operating activities before expenditures on asset retirement and changes in non-cash working capital. Funds from operations per Trust Unit is based on the number of Trust Units outstanding at each distribution record date. Both cash netbacks and payout ratio are dependent on the determination of funds from operations. Cash netbacks include the primary cash revenues and expenses on a per boe basis that comprise funds from operations. Payout ratio represents the distributions declared for the period as a percentage of funds from operations. Funds from operations reconciled to cash provided by operating activities is as follows:

	Three months ended June 30			Six months ended June 30		
	2007	2006	% change	2007	2006	% change
Cash provided by operating activities	\$ 49,932	\$ 44,741	12%	\$ 100,452	\$ 84,621	19%
Expenditures on asset retirement	(302)	414	(173)%	3,707	1,447	156%
Changes in non-cash working capital	13,004	(2,874)	(552)%	24,120	2,843	748%
Funds from operations	\$ 62,634	\$ 42,281	48%	\$ 128,279	\$ 88,911	44%

Forward-Looking Information

The information in this report contains certain forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", "would" and similar expressions. These statements involve substantial known and unknown risks and uncertainties, certain of which are beyond Advantage's control, including: the impact of general economic conditions; industry conditions; changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; fluctuations in commodity prices and foreign exchange and interest rates; stock market volatility and market valuations; volatility in market prices for oil and natural gas; liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; incorrect assessments of the value of acquisitions; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry and income trusts; geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves; obtaining required approvals of regulatory authorities and other risk factors set forth in Advantage's Annual Information Form which is available at www.advantageincome.com or www.sedar.com. Advantage's actual results, performance or achievement could differ materially from those expressed in, or implied by, such forward-looking statements and, accordingly, no assurances can be given that any of the events anticipated by the forward-looking statements will transpire or occur or, if any of them do, what benefits that Advantage will derive from them. Except as required by law, Advantage undertakes no obligation to publicly update or revise any forward-looking statements.

Proposed Business Combination with Sound Energy Trust

On July 9, 2007, the Fund and Sound Energy Trust (“Sound”) announced that their respective boards of directors had unanimously approved an agreement for the business combination of Advantage and Sound. The combined trust, which will retain the Advantage name, will be led by the existing Advantage management team.

The combination will be accomplished through a Plan of Arrangement (the “Arrangement”) by the exchange of each Sound Trust Unit for 0.30 of an Advantage Trust Unit or, at the election of the holder of Sound Trust Units, \$0.66 in cash and 0.2557 of an Advantage Trust Unit. In addition, all Sound Exchangeable Shares will be exchanged for Advantage Trust Units on the same ratio based on the conversion ratio in effect at the effective date of the Arrangement. The transaction exchange ratio reflected a premium to Sound Unitholders of 11.3% based on the respective closing price for each trust on July 6, 2007. The transaction is accretive to Advantage’s Unitholders on a production, cash flow, reserves and net asset value basis and will significantly increase Advantage’s tax pool position to a total of approximately \$1.6 billion, and Safe Harbour expansion room is anticipated to be approximately \$2.0 billion. Sound’s higher oil weighting, synergy with many of Advantage’s core properties and significant undeveloped land holdings of approximately 400,000 net undeveloped acres will further enhance the operating platform of Advantage. Sound Unitholders will receive a significant premium to recent trading prices and the opportunity to participate in a larger, more liquid entity with long-life, high-netback assets leading to better diversification. The combined trust will have an estimated enterprise value of \$2.5 billion.

Successful completion of the business combination is subject to stock exchange, court and regulatory approvals and the approval by at least two-thirds of Sound’s Unitholders and Sound Exchangeable Shareholders. It is anticipated that the Sound Unitholder meeting required to approve the Arrangement will be held, and the Arrangement is expected to close, in early September 2007, and that Sound Unitholders will receive Advantage’s September distribution payable on October 15, 2007. An information circular dated August 2, 2007 has been prepared by Sound and mailed to Sound Unitholders.

The Arrangement prohibits Sound from soliciting or initiating any discussion regarding any other business combination or sale of material assets, contains provisions to Advantage to match competing, unsolicited proposals and, subject to certain conditions, provides for a \$12 million termination fee payable to Advantage.

Overview

	Three months ended			Six months ended		
	June 30			June 30		
	2007	2006	% change	2007	2006	% change
Cash provided by operating activities (\$000)	\$ 49,932	\$ 44,741	12%	\$ 100,452	\$ 84,621	19%
Funds from operations (\$000)	\$ 62,634	\$ 42,281	48%	\$ 128,279	\$ 88,911	44%
per Trust Unit ⁽¹⁾	\$ 0.54	\$ 0.62	(13)%	\$ 1.13	\$ 1.41	(20)%
Net income (\$000)	\$ 4,531	\$ 23,905	(81)%	\$ 4,872	\$ 39,869	(88)%
per Trust Unit - Basic	\$ 0.04	\$ 0.38	(89)%	\$ 0.04	\$ 0.66	(94)%
- Diluted	\$ 0.04	\$ 0.38	(89)%	\$ 0.04	\$ 0.65	(94)%

⁽¹⁾ Based on Trust Units outstanding at each distribution record date.

Cash provided by operating activities increased 12%, funds from operations increased 48%, and funds from operations per Trust Unit decreased 13% for the three months ended June 30, 2007, as compared to the same period of 2006. For the six months ended June 30, 2007, cash provided by operating activities increased 19%, funds from operations increased 44%, and funds from operations per Trust Unit decreased 20%. The increase in cash provided by operating activities and funds from operations has been primarily due to the merger with Ketch Resources Trust (“Ketch”) that closed on June 23, 2006. The financial and operating results from the acquired Ketch properties are included in all 2007 figures but only eight days of these cash flows are included in the three and six month periods ended June 30, 2006, thereby explaining most variances. Conversely, funds from operations per Trust Unit has been negatively impacted during the periods due to higher operating costs and a higher average number of Trust Units outstanding. Operating costs per boe were \$11.26 in the first six months of 2007, an increase of 19% compared to \$9.43 for the same period of 2006. However, operating costs per boe decreased 6% from \$11.59 in the first quarter of 2007 to \$10.91 in the second quarter. The weighted average number of Trust Units has increased 82% from 2006 to 2007 mainly due to the Ketch acquisition, the Fund’s recent Trust Unit financing in the first quarter of 2007 and the distribution reinvestment plan. The financings have improved the bank indebtedness and provide financial flexibility. Net income decreased 81% for the three months and 88% for the six months ended June 30, 2007, compared to 2006. The lower net income has been primarily due to higher operating costs, as well as amortization of the management contract internalization and higher depletion and depreciation expense. The primary factor that causes significant variability of Advantage’s cash provided by operating activities, funds from operations, and net income is commodity prices. Refer to the section “Commodity Prices and Marketing” for a more detailed discussion of commodity prices and our price risk management.

Distributions

	Three months ended June 30			Six months ended June 30		
	2007	2006	% change	2007	2006	% change
Distributions declared (\$000)	\$ 52,096	\$ 53,498	(3)%	\$ 102,302	\$ 97,957	4%
per Trust Unit ⁽¹⁾	\$ 0.45	\$ 0.75	(40)%	\$ 0.90	\$ 1.50	(40)%
Payout ratio (%)	83%	127%	(44)%	80%	110%	(30)%

⁽¹⁾ Based on Trust Units outstanding at each distribution record date.

Total distributions decreased 3% for the three months and increased 4% for the six months ended June 30, 2007 when compared to the same periods in 2006. Total distributions are similar as a result of the decrease in the distributions per Trust Unit in January 2007, being offset by the increased Trust Units outstanding from the continued growth and development of the Fund. Since natural gas prices have been very weak during the 2006/2007 winter season, we reduced the distribution level to more appropriately reflect the current commodity price environment. Distributions per Trust Unit were \$0.45 for the three months and \$0.90 for the six months ended June 30, 2007, representing a decrease of 40% from 2006. This reduction positively impacted the payout ratio for the second quarter of 2007, which was 83%, down from 127% during the same period of 2006. For the six months ended June 30, 2007, the payout ratio was 80%, significantly lower than the 110% payout ratio experienced during the same period of 2006. The monthly distribution is currently \$0.15 per Trust Unit. To mitigate the persisting risk associated with lower natural gas prices and the resulting negative impact on distributions, the Fund implemented a hedging program in 2006 with 54% of natural gas hedged for April to October 2007. See "Commodity Price Risk" section for a more detailed discussion of our price risk management.

Distributions are determined by Management and the Board of Directors. We closely monitor our distribution policy considering forecasted cash flows, optimal debt levels, capital spending activity, taxability to Unitholders, working capital requirements, and other potential cash expenditures. Distributions are announced monthly and are based on the cash available after retaining a portion to meet such spending requirements. The level of distributions are primarily determined by cash flows received from the production of oil and natural gas from existing Canadian resource properties and will be susceptible to the risks and uncertainties associated with the oil and natural gas industry generally. If the oil and natural gas reserves associated with the Canadian resource properties are not supplemented through additional development or the acquisition of additional oil and natural gas properties, our distributions will decline over time in a manner consistent with declining production from typical oil and natural gas reserves. Therefore, distributions are highly dependent upon our success in exploiting the current reserve base and acquiring additional reserves. Furthermore, monthly distributions we pay to Unitholders are highly dependent upon the prices received for such oil and natural gas production. Oil and natural gas prices can fluctuate widely on a month-to-month basis in response to a variety of factors that are beyond our control. Declines in oil or natural gas prices will have an adverse effect upon our operations, financial condition, reserves and ultimately on our ability to pay distributions to Unitholders. The Fund attempts to mitigate the volatility in commodity prices through our hedging program. It is our long-term objective to provide stable and sustainable distributions to the Unitholders, while continuing to grow the Fund. However, given that funds from operations can vary significantly from month-to-month due to these factors, the Fund may utilize various financing alternatives as an interim measure to maintain stable distributions.

Revenue

(\$000)	Three months ended June 30			Six months ended June 30		
	2007	2006	% change	2007	2006	% change
Natural gas excluding hedging	\$ 74,760	\$ 39,553	89%	\$ 153,093	\$ 91,011	68%
Realized hedging gains (losses)	(136)	-	-	4,484	-	-
Natural gas including hedging	\$ 74,624	\$ 39,553	89%	\$ 157,577	\$ 91,011	73%
Crude oil and NGLs excluding hedging	\$ 50,371	\$ 41,213	22%	\$ 101,310	\$ 76,656	32%
Realized hedging gains	80	-	-	1,690	-	-
Crude oil and NGLs including hedging	\$ 50,451	\$ 41,213	22%	\$ 103,000	\$ 76,656	34%
Total revenue	\$ 125,075	\$ 80,766	55%	\$ 260,577	\$ 167,667	55%

Natural gas revenues, excluding hedging, have increased 89% for the three months and 68% for the six months ended June 30, 2007, compared to 2006. Crude oil and NGL revenues, excluding hedging, have increased by 22% for the three months and 32% for the six months ended June 30, 2007. Revenues have increased due to additional production from the Ketch merger as well as stronger natural gas prices in the second quarter of 2007. For the six months ended June 30, 2007, the Fund recognized natural gas and crude oil hedging gains of \$6.2 million primarily attributable to weak commodity prices during the first quarter of 2007.

Production

	Three months ended June 30			Six months ended June 30		
	2007	2006	% change	2007	2006	% change
Natural gas (mcf/d)	108,978	70,293	55%	111,636	68,043	64%
Crude oil (bbls/d)	6,615	5,321	24%	7,083	5,467	30%
NGLs (bbls/d)	2,337	1,272	84%	2,369	1,209	96%
Total (boe/d)	27,115	18,309	48%	28,058	18,017	56%
Natural gas (%)	67%	64%		67%	63%	
Crude oil (%)	24%	29%		25%	30%	
NGLs (%)	9%	7%		8%	7%	

The Fund's total daily production averaged 27,115 boe/d for the three months and 28,058 boe/d for the six months ended June 30, 2007, an increase of 48% and 56%, respectively, compared with the same periods of 2006. Natural gas production increased 55%, crude oil production increased 24%, and NGLs production increased 84% for the second quarter of 2007. For the six months ended June 30, 2007, natural gas production increased 64%, crude oil production increased 30%, and NGLs production increased 96%. The increase in production from 2006 has been primarily attributed to the Ketch acquisition, which closed June 23, 2006.

For the second quarter, production decreased 7% from the first quarter of 2007. Our successful first quarter 2007 drilling program at Martin Creek, Nevis, Chigwell, and Willesden Green, as well as other areas in Southern Alberta and Saskatchewan, has moderately offset declines. In addition, our flattening production platform, resulting from our continued focus on long life assets, is contributing to a stable operating foundation. Significant third party facility outages were realized during the quarter as well as a prolonged spring break-up, which was exacerbated by very wet weather conditions.

For the remainder of the year, we expect a major third party plant turnaround and other smaller facility outages during the third quarter, which will impact production levels.

Commodity Prices and Marketing

Natural Gas

(\$/mcf)	Three months ended June 30			Six months ended June 30		
	2007	2006	% change	2007	2006	% change
Realized natural gas prices						
Excluding hedging	\$ 7.54	\$ 6.18	22%	\$ 7.58	\$ 7.39	3%
Including hedging	\$ 7.52	\$ 6.18	22%	\$ 7.80	\$ 7.39	6%
AECO monthly index	\$ 7.37	\$ 6.28	17%	\$ 7.42	\$ 7.78	(5)%

Realized natural gas prices, excluding hedging, increased 22% for the three months and 3% for the six months ended June 30, 2007, as compared to 2006. The price of natural gas is primarily based on supply and demand fundamentals in the North American marketplace. The 2006/2007 winter was generally mild, with inventory levels remaining higher than average, causing continued downward pressure on commodity prices. Natural gas prices have subsequently declined further due to significant summer inventory injections and excess supply concerns resulting from mild summer weather and lack of storm activity in the Gulf of Mexico. We continue to believe that the long-term pricing fundamentals for natural gas remain strong. These fundamentals include (i) the continued strength of crude oil prices, which has eliminated the economic advantage of fuel switching away from natural gas, (ii) significantly less natural gas drilling in Canada projected for 2007, which will reduce productivity to offset declines and (iii) the increasing focus on resource style natural gas wells, which have high initial declines and require a higher threshold economic price than conventional gas drilling.

Crude Oil and NGLs

(\$/bbl)	Three months ended June 30			Six months ended June 30		
	2007	2006	% change	2007	2006	% change
Realized crude oil prices						
Excluding hedging	\$ 64.23	\$ 71.14	(10)%	\$ 61.48	\$ 65.16	(6)%
Including hedging	\$ 64.37	\$ 71.14	(10)%	\$ 62.79	\$ 65.16	(4)%
Realized NGLs prices						
Excluding hedging	\$ 55.05	\$ 58.43	(6)%	\$ 52.47	\$ 55.67	(6)%
Realized crude oil and NGLs prices						
Excluding hedging	\$ 61.84	\$ 68.69	(10)%	\$ 59.22	\$ 63.44	(7)%
Including hedging	\$ 61.93	\$ 68.69	(10)%	\$ 60.21	\$ 63.44	(5)%
WTI (\$US/bbl)	\$ 65.02	\$ 70.75	(8)%	\$ 61.59	\$ 67.33	(9)%
\$US/\$Canadian exchange rate	\$ 0.91	\$ 0.90	1%	\$ 0.88	\$ 0.88	0%

Realized crude oil and NGLs prices, excluding hedging, decreased 10% for the three months and 7% for the six months ended June 30, 2007, as compared to the same periods of 2006. Advantage's crude oil prices are based on the benchmark pricing of West Texas Intermediate Crude ("WTI") adjusted for quality, transportation costs and \$US/\$Canadian exchange rates. For the three and six months ended June 30, 2007, WTI decreased 8% and 9%, respectively, compared to 2006. Advantage's realized crude oil price has not changed to the same extent as WTI due to the changes in Canadian crude oil differentials relative to WTI. The price of WTI fluctuates based on worldwide supply and demand fundamentals. There has been significant price volatility experienced over the last several years whereby WTI has reached historic high levels. Many developments have resulted in the current price levels, including significant geopolitical issues. Early in 2006, prices were strong due to concerns regarding the lack of North American refining capacity, and the continued strength of global demand. The mild 2005/2006 winter and the surge in crude imports to North America resulted in significantly higher inventories that prompted a relative price decrease during the end of 2006. Prices have strengthened once again in early 2007 due to continued civil unrest in the Middle East and production restrictions by the OPEC cartel. With the current high price levels, it is notable that demand has remained resilient. We believe that the pricing fundamentals for crude oil remain strong with many factors affecting the continued strength including (i) supply management and supply restrictions by the OPEC cartel, (ii) ongoing civil unrest in Venezuela, Nigeria, and the Middle East, (iii) strong world wide demand, particularly in China, India and the United States and (iv) North American refinery capacity constraints.

Commodity Price Risk

The Fund's operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by economic and, in the case of oil prices, political factors. Supply and demand factors, including weather and general economic conditions as well as conditions in other oil and natural gas regions, impact prices. Any movement in oil and natural gas prices could have an effect on the Fund's financial condition and therefore on the distributions to holders of Advantage Trust Units. As current and future practice, Advantage has established a financial hedging strategy and may manage the risk associated with changes in commodity prices by entering into derivatives. These commodity price risk management activities could expose Advantage to losses or gains. To the extent that Advantage engages in risk management activities related to commodity prices, it will be subject to credit risk associated with counterparties with which it contracts. Credit risk is mitigated by entering into contracts with only stable, creditworthy parties and through frequent reviews of exposures to individual entities.

Currently, the Fund has the following derivatives in place:

Description of Derivative	Term	Volume	Average Price
Natural gas - AECO			
Fixed price	April 2007 to October 2007	9,478 mcf/d	Cdn\$7.16/mcf
Fixed price	April 2007 to October 2007	9,478 mcf/d	Cdn\$7.55/mcf
Fixed price	November 2007 to March 2008	7,109 mcf/d	Cdn\$9.54/mcf
Collar	November 2007 to March 2008	9,478 mcf/d	Floor Cdn\$8.44/mcf Ceiling Cdn\$10.29/mcf
Collar	November 2007 to March 2008	7,109 mcf/d	Floor Cdn\$8.70/mcf Ceiling Cdn\$10.71/mcf
Crude oil - WTI			
Collar	October 2006 to September 2007	1,000 bbls/d	Floor US\$65.00/bbl Ceiling US\$90.00/bbl

As at June 30, 2007 the fair value of the derivatives outstanding was an asset of approximately \$8,530,000. For the six months ended June 30, 2007, \$1,903,000 was recognized in income as an unrealized derivative loss due to a decrease in the fair value from December 31, 2006 and \$6,174,000 was recognized in income as a realized derivative gain, which partially alleviated lower revenue from reduced commodity prices. The valuation of the derivatives is the estimated fair value to settle the contracts as at June 30, 2007 and is based on pricing models, estimates, assumptions and market data available at that time. The actual gain or loss realized on cash settlement can vary materially due to subsequent fluctuations in commodity prices as compared to the valuation assumptions. The Fund does not apply hedge accounting and current accounting standards require changes in the fair value to be included in the consolidated statement of income and comprehensive income as an unrealized derivative gain or loss with a corresponding derivative asset or liability recorded on the balance sheet.

In addition, the Fund has the following physical natural gas contracts in place with gains and losses recognized in earnings as the contracts settle:

Description of Physical Contract	Term	Volume	Average Price
Natural gas - AECO			
Collar	April 2007 to October 2007	4,739 mcf/d	Floor Cdn\$7.12/mcf Ceiling Cdn\$8.67/mcf
Collar	April 2007 to October 2007	4,739 mcf/d	Floor Cdn\$6.86/mcf Ceiling Cdn\$9.13/mcf
Collar	April 2007 to October 2007	9,478 mcf/d	Floor Cdn\$7.39/mcf Ceiling Cdn\$9.63/mcf
Collar	April 2007 to October 2007	9,478 mcf/d	Floor Cdn\$6.33/mcf Ceiling Cdn\$7.20/mcf

Currently, the Fund has fixed the commodity price on anticipated production as follows:

Commodity	Approximate Production		
	Hedged, Net of Royalties	Minimum Price	Maximum Price
Natural gas - AECO			
Summer 2007	54%	Cdn\$7.08/mcf	Cdn\$8.09/mcf
Winter 2007/2008	28%	Cdn\$8.85/mcf	Cdn\$10.19/mcf
Crude Oil - WTI			
Summer 2007	14%	US\$65.00/bbl	US\$90.00/bbl

Royalties

	Three months ended			Six months ended		
	June 30			June 30		
	2007	2006	% change	2007	2006	% change
Royalties, net of Alberta Royalty Credit (\$000)	\$ 22,749	\$ 13,822	65%	\$ 48,914	\$ 30,162	62%
per boe	\$ 9.22	\$ 8.30	11%	\$ 9.63	\$ 9.25	4%
As a percentage of revenue, excluding hedging	18.2%	17.1%	1.1%	19.2%	18.0%	1.2%

Advantage pays royalties to the owners of mineral rights from which we have leases. The Fund currently has mineral leases with provincial governments, individuals and other companies. Royalties for 2006 are shown net of the Alberta Royalty Credit, which was a royalty rebate provided by the Alberta government to certain producers and was eliminated effective January 1, 2007. Royalties have increased in total due to the increase in revenue from higher production and have increased on a per boe basis due to higher natural gas prices. Royalties as a percentage of revenue, excluding hedging, have increased slightly from the 2006 period due to the inclusion of slightly higher royalty rate properties from the Ketch acquisition. We expect the royalty rate to remain comparable for the remainder of 2007.

Operating Costs

	Three months ended			Six months ended		
	June 30			June 30		
	2007	2006	% change	2007	2006	% change
Operating costs (\$000)	\$ 26,919	\$ 15,673	72%	\$ 57,189	\$ 30,739	86%
per boe	\$ 10.91	\$ 9.41	16%	\$ 11.26	\$ 9.43	19%

Total operating costs increased 72% for the three months and 86% for the six months ended June 30, 2007 as compared to 2006, mainly due to increased production from the Ketch acquisition. Operating costs per boe increased 16% for the three months and 19% for the six months ended June 30, 2007, mainly due to temporary decreases in production levels related to second quarter turnaround activity, an extended and unusually wet spring break-up, and increased service and supply costs as the industry experienced an overall labour cost increase. However, per unit operating costs decreased by 6% and total operating costs decreased 11% when compared to the three months ended March 31, 2007. This decrease reflects the absence of one-time cold weather related costs but is offset by lower production levels. We will continue to be opportunistic and proactive in pursuing optimization initiatives that will improve our operating cost structure. A significant operating cost that Advantage has been successful in partially stabilizing is electricity associated with field operations. The Fund has been active in preserving the price of power by hedging 3.5 MW at \$56.68/MWh for 2007 and 3.0 MW at \$54.00/MWh for 2008, which represents a substantial portion of our power usage. We expect that operating costs per boe will be in the range of \$10.50 to \$11.50 for the 2007 year.

General and Administrative

	Three months ended			Six months ended		
	June 30			June 30		
	2007	2006	% change	2007	2006	% change
General and administrative expense (\$000)	\$ 4,232	\$ 2,420	75%	\$ 8,948	\$ 4,386	104%
per boe	\$ 1.72	\$ 1.45	19%	\$ 1.76	\$ 1.34	31%

General and administrative (“G&A”) expense has increased 75% for the three months and 104% for the six months ended June 30, 2007, as compared to 2006. G&A per boe increased 19% for the three months and 31% for the six months when compared to the same periods of 2006. G&A expense has increased overall and per boe primarily due to an increase in staff levels that have resulted from the Ketch acquisition and growth of the Fund. Additionally, the Ketch acquisition was conditional on Advantage internalizing the external management contract structure and eliminating all related fees for a more typical employee compensation arrangement. The new employee compensation plan has resulted in higher G&A expense that is offset by the elimination of future management fees and performance incentive. Prior to elimination of the management contract, the quarterly management fee and annual performance incentive were not included within G&A.

Unit-Based Compensation

Advantage’s current employee compensation includes a Restricted Trust Unit Plan (the “Plan”), as approved by the Unitholders on June 23, 2006, and Trust Units issuable for the retention of certain employees of the Fund. The purpose of the long-term compensation plans is to retain and attract employees, to reward and encourage performance, and to focus employees on operating and financial performance that result in lasting Unitholder return.

The Plan authorizes the Board of Directors to grant Restricted Trust Units (“RTUs”) to directors, officers, or employees of the Fund. The number of RTUs granted is based on the Fund’s Trust Unit return for a calendar year and compared to a peer group approved by the Board of Directors. The Trust Unit return is calculated at the end of the year and is primarily based on the year-over-year change in the Trust Unit price plus distributions. The RTU grants vest one third immediately on grant date, with the remaining two thirds vesting evenly on the following two yearly anniversary dates. The holders of RTUs may elect to receive cash upon vesting in lieu of the number of Trust Units to be issued, subject to consent of the Fund. Compensation cost related to the Plan is based on the “fair value” of the RTUs at the grant date and is recognized as compensation expense over the service period. This valuation incorporates the period end Trust Unit price, the estimated number of RTUs to vest, and certain management estimates. The maximum fair value of RTUs granted in any one calendar year is limited to 175% of the base salaries of those individuals participating in the Plan for such period. No RTUs have been granted under the Plan at this time and accordingly, no compensation expense relating to the RTUs has been recognized in the interim financial statements. Once the calendar year is completed and the final Trust Unit return is calculated for the return period RTUs may be granted and consequently, compensation expense may be recognized at that time. As the Fund did not meet the 2006 grant thresholds, there was no RTU grant made for the 2006 year.

For the six months ended June 30, 2007, the Fund has accrued unit-based compensation expense of \$0.6 million and has capitalized \$0.2 million related to Trust Units issuable for the retention of certain employees of the Fund.

Management Fee, Performance Incentive, and Management Internalization

	Three months ended			Six months ended		
	June 30			June 30		
	2007	2006	% change	2007	2006	% change
Management fee (\$000)	\$ -	\$ 55	(100)%	\$ -	\$ 887	(100)%
per boe	\$ -	\$ 0.03	(100)%	\$ -	\$ 0.27	(100)%
Performance incentive (\$000)	\$ -	\$ (300)	(100)%	\$ -	\$ 2,380	(100)%
Management internalization (\$000)	\$ 5,350	\$ 524	921%	\$ 10,719	\$ 524	1946%

Prior to the Ketch merger, the Manager received both a management fee and a performance incentive fee as compensation pursuant to the Management Agreement approved by the Board of Directors. As a condition of the merger with Ketch, the Fund and the Manager reached an agreement to internalize the management contract arrangement. As part of the agreement, Advantage agreed to purchase all of the outstanding shares of the Manager pursuant to the terms of the Arrangement, thereby eliminating the management fee and performance incentive effective April 1, 2006. The Trust Unit consideration issued in exchange for the outstanding shares of

the Manager was placed in escrow for a 3-year period and is being deferred and amortized into income as management internalization expense over the specific vesting periods during which employee services are provided.

Interest

	Three months ended			Six months ended		
	June 30			June 30		
	2007	2006	% change	2007	2006	% change
Interest expense (\$000)	\$ 5,005	\$ 3,940	27%	\$ 10,192	\$ 7,133	43%
per boe	\$ 2.03	\$ 2.36	(14)%	\$ 2.01	\$ 2.19	(8)%
Average effective interest rate	5.4%	4.9%	0.5%	5.4%	4.9%	0.5%
Bank indebtedness at June 30 (\$000)				\$377,812	\$500,837	(25)%

Interest expense has increased 27% for the three months and 43% for the six months ended June 30, 2007, as compared to 2006. Interest expense per boe has decreased 14% for the three months and 8% for the six months ended June 30, 2007. The increase in total interest expense is primarily attributable to a higher average debt level associated with the growth of the Fund, an increase in the average effective interest rates, and the merger with Ketch, which included the assumption of Ketch's additional bank indebtedness. Interest expense per boe has decreased as we have reduced our bank indebtedness relative to our level of production. The bank indebtedness at June 30, 2007 decreased 25% from the prior year as we issued Trust Units in early 2007 to reduce debt. We monitor the debt level to ensure an optimal mix of financing and cost of capital that will provide a maximum return to Unitholders. Our current credit facilities have been a favorable financing alternative with an effective interest rate of only 5.4% for the three and six months ended June 30, 2007. The Fund's interest rates are primarily based on short term Bankers Acceptance rates plus a stamping fee.

Interest and Accretion on Convertible Debentures

	Three months ended			Six months ended		
	June 30			June 30		
	2007	2006	% change	2007	2006	% change
Interest on convertible debentures (\$000)	\$ 3,293	\$ 2,268	45%	\$ 6,531	\$ 4,613	42%
per boe	\$ 1.33	\$ 1.36	(2)%	\$ 1.29	\$ 1.41	(9)%
Accretion on convertible debentures (\$000)	\$ 605	\$ 437	38%	\$ 1,204	\$ 898	34%
per boe	\$ 0.25	\$ 0.26	(4)%	\$ 0.24	\$ 0.28	(14)%
Convertible debentures maturity value at June 30 (\$000)				\$180,725	\$180,795	0%

Interest on convertible debentures has increased 45% for the three months and 42% for the six months ended June 30, 2007, as compared to 2006. Accretion on convertible debentures has increased 38% for the three months and 34% for the six months ended June 30, 2007. The increases in total interest and accretion are due to Advantage assuming Ketch's 6.50% convertible debentures in the merger. The increased interest and accretion from the additional debentures has been slightly offset due to the exchange of convertible debentures to Trust Units during 2006 that pay distributions rather than interest. Interest and accretion per boe has decreased as our convertible debentures outstanding has reduced relative to our level of production. During the six months ended June 30, 2007, \$5,000 convertible debentures were converted resulting in the issuance of 375 Trust Units.

Cash Netbacks

	Three months ended				Six months ended			
	June 30				June 30			
	2007		2006		2007		2006	
	\$000	per boe	\$000	per boe	\$000	per boe	\$000	per boe
Revenue	\$ 125,131	\$ 50.71	\$ 80,766	\$ 48.48	\$ 254,403	\$ 50.09	\$ 167,667	\$ 51.42
Realized gain (loss) on derivatives	(56)	(0.02)	-	-	6,174	1.22	-	-
Royalties, net of Alberta Royalty Credit	(22,749)	(9.22)	(13,822)	(8.30)	(48,914)	(9.63)	(30,162)	(9.25)
Operating costs	(26,919)	(10.91)	(15,673)	(9.41)	(57,189)	(11.26)	(30,739)	(9.43)
Operating	\$ 75,407	\$ 30.56	\$ 51,271	\$ 30.77	\$ 154,474	\$ 30.42	\$ 106,766	\$ 32.74
General and administrative	(4,232)	(1.72)	(2,420)	(1.45)	(8,948)	(1.76)	(4,386)	(1.34)
Management fee	-	-	(55)	(0.03)	-	-	(887)	(0.27)
Interest	(5,005)	(2.03)	(3,940)	(2.36)	(10,192)	(2.01)	(7,133)	(2.19)
Interest on convertible debentures	(3,293)	(1.33)	(2,268)	(1.36)	(6,531)	(1.29)	(4,613)	(1.41)
Income and capital taxes	(243)	(0.10)	(307)	(0.18)	(524)	(0.10)	(836)	(0.26)
Funds from operations	\$ 62,634	\$ 25.38	\$ 42,281	\$ 25.39	\$ 128,279	\$ 25.26	\$ 88,911	\$ 27.27

Funds from operations of Advantage for the quarter ended June 30, 2007 increased to \$62.6 million from \$42.3 million in the prior year. Funds from operations for the six months ended June 30, 2007 increased to \$128.3 million from \$88.9 million compared to 2006. The cash netback per boe for the three months ended June 30, 2007 remained comparable to the same quarter of 2006, but decreased 7% from \$27.27 to \$25.26 for the six months ended June 30, 2007. The lower cash netback per boe for the six months ended June 30, 2007 is primarily due to higher operating costs. Operating costs per boe for the six months ended June 30, 2007 were \$11.26, an increase of 19% from the \$9.43 experienced in 2006. Operating costs have steadily increased over the past year due to significantly higher field costs associated with supplies and services that has resulted from the high level of industry activity and an overall industry labour cost increase. Although we have experienced significant upward pressure on operating costs, it is notable that operating costs per boe for the quarter decreased 6% compared to the three months ended March 31, 2007.

Depletion, Depreciation and Accretion

	Three months ended			Six months ended		
	June 30			June 30		
	2007	2006	% change	2007	2006	% change
Depletion, depreciation & accretion (\$000)	\$ 61,365	\$ 33,164	85%	\$ 125,283	\$ 63,187	98%
per boe	\$ 24.87	\$ 19.91	25%	\$ 24.67	\$ 19.38	27%

Depletion and depreciation of property and equipment is provided on the “unit-of-production” method based on total proved reserves. The depletion, depreciation and accretion (“DD&A”) provision has increased 85% for the three months and 98% for the six months ended June 30, 2007 due to the considerable increases of daily production volumes, mainly from the Ketch acquisition and the increase in the DD&A rate per boe compared to the prior year. The higher DD&A per boe was due to a higher valuation for the Ketch reserves than accumulated from prior acquisitions and development activities.

Taxes

Current taxes paid or payable for the quarter ended June 30, 2007 amounted to \$0.2 million, comparable to the \$0.3 million expensed for the same period of 2006. Current taxes primarily represent Saskatchewan resource surcharge, which is based on the petroleum and natural gas revenues within the province of Saskatchewan.

Future income taxes arise from differences between the accounting and tax bases of the assets and liabilities. For the six months ended June 30, 2007, the Fund recognized an income tax reduction of \$16.3 million compared to a reduction of \$17.4 million for 2006. The impact of the Specified Investment Flow-Through Entity (“SIFT”) tax legislation is reflected in the second quarter of 2007. The new tax law includes altering the tax treatment of income trusts by subjecting income trusts to a two-tier tax structure, similar to that of corporations, whereby the taxable portion of distributions paid by trusts will be subject to tax at the trust level and at the Unitholder level. The rules are effective for tax years beginning in 2011 for existing publicly-traded trusts. As at June 30, 2007,

we had a future income tax liability balance of \$45.6 million, compared to \$61.9 million at December 31, 2006. Canadian generally accepted accounting principles require that a future income tax liability be recorded when the book value of assets exceeds the balance of tax pools.

Contractual Obligations and Commitments

The Fund has contractual obligations in the normal course of operations including purchases of assets and services, operating agreements, transportation commitments, sales contracts and convertible debentures. These obligations are of a recurring and consistent nature and impact cash flow in an ongoing manner. The following table is a summary of the Fund's remaining contractual obligations and commitments. Advantage has no guarantees or off-balance sheet arrangements other than as disclosed.

(\$ millions)	Total	Payments due by period				2011 & thereafter
		2007	2008	2009	2010	
Building leases	\$ 4.3	\$ 1.1	\$ 1.4	\$ 0.8	\$ 0.8	\$ 0.2
Capital leases	5.6	1.0	1.1	0.8	0.8	1.9
Pipeline/transportation	4.7	1.9	2.1	0.6	0.1	-
Convertible debentures ⁽¹⁾	180.7	1.4	5.4	57.1	70.0	46.8
Total contractual obligations	\$ 195.3	\$ 5.4	\$ 10.0	\$ 59.3	\$ 71.7	\$ 48.9

⁽¹⁾ As at June 30, 2007, Advantage had \$180.7 million convertible debentures outstanding. Each series of convertible debentures are convertible to Trust Units based on an established conversion price. The Fund expects that the obligations related to convertible debentures will be settled either directly or indirectly through the issuance of Trust Units.

⁽²⁾ Bank indebtedness of \$377.8 million has been excluded from the contractual obligations table as the credit facilities constitute a revolving facility for a 364 day term which is extendible annually for a further 364 day revolving period at the option of the syndicate. If not extended, the revolving credit facility is converted to a two year term facility with the first payment due one year and one day after commencement of the term.

Liquidity and Capital Resources

The following table is a summary of the Fund's capitalization structure.

(\$000, except as otherwise indicated)	June 30, 2007
Bank indebtedness (long-term)	\$ 377,812
Working capital deficit ⁽¹⁾	11,512
Net debt	\$ 389,324
Trust Units outstanding (000)	116,091
Trust Unit closing market price (\$/Trust Unit)	\$ 15.00
Market value	\$ 1,741,365
Capital lease obligation (long-term)	\$ 3,429
Convertible debentures maturity value (long-term)	179,245
Total capitalization	\$ 2,313,363

⁽¹⁾ Working capital deficit includes accounts receivable, prepaid expenses and deposits, accounts payable and accrued liabilities, distributions payable, and the current portion of capital lease obligations and convertible debentures.

Unitholders' Equity and Convertible Debentures

Advantage has utilized a combination of Trust Units, convertible debentures and bank debt to finance acquisitions and development activities.

As at June 30, 2007, the Fund had 116.1 million Trust Units outstanding. On February 14, 2007 Advantage issued 7,800,000 Trust Units, plus an additional 800,000 Trust Units upon exercise of the Underwriters' over-allotment option on March 7, 2007, at \$12.80 per Trust Unit for approximate net proceeds of \$104.1 million (net of Underwriters' fees and other issue costs of \$6.0 million). The net proceeds of the offering were used to pay down bank indebtedness and to subsequently fund capital and general corporate expenditures. As at August 14, 2007, Advantage had 116.3 million Trust Units issued and outstanding.

On July 24, 2006, Advantage adopted a Premium Distribution^(TM), Distribution Reinvestment and Optional Trust Unit Purchase Plan (the "Plan"). For Unitholders that elect to participate in the Plan, Advantage will settle the monthly distribution obligation through the issuance of additional Trust Units at 95% of the Average Market Price (as defined in the Plan). Unitholder enrollment in the Premium Distribution^(TM) component of the Plan effectively authorizes the subsequent disposal of the issued Trust Units in exchange for a cash payment equal to 102% of the cash distributions that the Unitholder would otherwise have received if they did not participate in the Plan. During the six months ended June 30, 2007, 2,076,686 Trust Units were issued as a result of the Plan, generating \$24.6 million reinvested in the Fund and representing an approximate 23% participation rate.

As at June 30, 2007, the Fund had \$180.7 million convertible debentures outstanding that were convertible to 8.3 million Trust Units based on the applicable conversion prices. During the six months ended June 30, 2007, \$5,000 of convertible debentures were converted resulting in the issuance of 375 Trust Units and as at August 14, 2007, the convertible debentures outstanding have not changed from June 30, 2007.

Bank Indebtedness, Credit Facility and Other Obligations

At June 30, 2007, Advantage had bank indebtedness outstanding of \$377.8 million. The Fund has a \$600 million credit facility agreement consisting of a \$580 million extendible revolving loan facility and a \$20 million operating loan facility. The current credit facilities are secured by a \$1 billion floating charge demand debenture, a general security agreement and a subordination agreement from the Fund covering all assets and cash flows.

At June 30, 2007, Advantage had a working capital deficiency of \$11.5 million. Our working capital includes items expected for normal operations such as trade receivables, prepaids, deposits, trade payables and accruals as well as the current portion of capital lease obligations and convertible debentures. Working capital varies primarily due to the timing of such items, the current level of business activity including our capital program, commodity price volatility, and seasonal fluctuations. Advantage has no unusual working capital requirements. We do not anticipate any problems in meeting future obligations as they become due given the strength of our funds from operations. It is also important to note that working capital is effectively integrated with Advantage's operating credit facility, which assists with the timing of cash flows as required.

During the quarter ended June 30, 2007, Advantage entered a new lease arrangement that resulted in the recognition of a fixed asset addition and capital lease obligation of \$4.1 million. The lease obligation bears interest at 5.8% and is secured by the related equipment. The lease term expires June 2011 with a final purchase obligation of \$1.5 million at which time ownership of the equipment will transfer to Advantage. In addition, Advantage has one other capital lease outstanding that was assumed from a prior corporate acquisition.

Capital Expenditures

(\$000)	Three months ended June 30		Six months ended June 30	
	2007	2006	2007	2006
Land and seismic	\$ 1,581	\$ 1,050	\$ 3,921	\$ 3,278
Drilling, completions and workovers	15,475	20,708	42,610	34,715
Well equipping and facilities	8,464	5,899	28,574	10,187
Other	158	125	269	591
	\$ 25,678	\$ 27,782	\$ 75,374	\$ 48,771
Property acquisitions	-	-	12,851	-
Property dispositions	-	-	(427)	-
Total capital expenditures	\$ 25,678	\$ 27,782	\$ 87,798	\$ 48,771

Advantage's growth strategy has been to acquire properties in or near areas where we have large land positions, shallow to medium depth drilling opportunities, and preserve a balance of year round access. We focus on areas where past activity has yielded long-life reserves with high cash netbacks. With the integration of the Ketch assets, Advantage is very well positioned to selectively exploit the highest value-generating drilling opportunities given the size, strength and diversity of our asset base. As a result, the Fund has a high level of flexibility to distribute its capital program and ensure a risk-balanced platform of projects. Our preference is to operate a high percentage of our properties such that we can maintain control of capital expenditures, operations and cash flows.

For the three month period ended June 30, 2007, the Fund spent a net \$25.7 million. Approximately \$6.1 million was expended on facility completion and \$15.5 million was expended on drilling and completion operations where the Fund drilled a total of 5.8 net (10 gross) wells at a 100% success rate. During the quarter we drilled 1 net (1 gross) oil well at Nevis, 1 net (1 gross) oil well at Chigwell, 1 net (1 gross) gas well at Black, 0.6 net (3 gross) oil wells at Lashburn, 0.7 net (1 gross) oil well at Sunset, as well as several wells at

other minor properties. Total capital spending in the quarter included \$3.8 million at Nevis, \$3.0 million at Martin Creek, \$3.0 million in Southeast Saskatchewan, \$2.5 million at Willesden Green, \$2.4 million at Sunset, and \$2.4 million at Red Deer. The \$12.9 million property acquisition in the first quarter was for producing properties and undeveloped land at the Fund's core area, Nevis.

Capital spending, before property acquisitions and dispositions, for the six months ended June 30, 2007 was below our internal plans due to prolonged wet weather resulting in a long spring break-up and restricted access. The reduced spending has been partially responsible for delays in bringing on expected production in the second quarter of 2007. However, the Fund still anticipates spending the full capital budget for the 2007 year, in addition to the Sound business combination.

The following table summarizes the various funding requirements during the six months ended June 30, 2007 and the sources of funding to meet those requirements.

Sources and Uses of Funds

(\$000)	Six months ended June 30, 2007
Sources of funds	
Funds from operations	\$ 128,279
Units issued, net of costs	104,486
Property dispositions	427
	\$ 233,192
Uses of funds	
Distributions to Unitholders	\$ 79,305
Expenditures on property and equipment	75,374
Decrease in bank indebtedness	32,762
Increase in working capital	27,123
Property acquisitions	12,851
Expenditures on asset retirement	3,707
Reduction of capital lease obligations	2,070
	\$ 233,192

Quarterly Performance

(\$000, except as otherwise indicated)	2007			2006			2005	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Daily production								
Natural gas (mcf/d)	108,978	114,324	117,134	122,227	70,293	65,768	72,587	75,994
Crude oil and NGLs (bbls/d)	8,952	9,958	9,570	9,330	6,593	6,760	7,106	7,340
Total (boe/d)	27,115	29,012	29,092	29,701	18,309	17,721	19,204	20,006
Average prices								
Natural gas (\$/mcf)								
Excluding hedging	\$ 7.54	\$ 7.61	\$ 6.90	\$ 5.89	\$ 6.18	\$ 8.69	\$ 11.68	\$ 8.25
Including hedging	\$ 7.52	\$ 8.06	\$ 7.27	\$ 5.90	\$ 6.18	\$ 8.69	\$ 10.67	\$ 7.79
AECO monthly index	\$ 7.37	\$ 7.46	\$ 6.36	\$ 6.03	\$ 6.28	\$ 9.31	\$ 11.68	\$ 8.15
Crude oil and NGLs (\$/bbl)								
Excluding hedging	\$ 61.84	\$ 56.84	\$ 54.58	\$ 67.77	\$ 68.69	\$ 58.26	\$ 60.14	\$ 66.00
Including hedging	\$ 61.93	\$ 58.64	\$ 55.86	\$ 67.77	\$ 68.69	\$ 58.26	\$ 59.53	\$ 61.10
WTI (US\$/bbl)	\$ 65.02	\$ 58.12	\$ 60.21	\$ 70.55	\$ 70.75	\$ 63.88	\$ 60.04	\$ 63.17
Total revenues (before royalties)	\$ 125,075	\$ 135,502	\$ 127,539	\$ 124,521	\$ 80,766	\$ 86,901	\$ 110,172	\$ 95,715
Net income	\$ 4,531	\$ 341	\$ 8,736	\$ 1,209	\$ 23,905	\$ 15,964	\$ 25,846	\$ 18,674
per Trust Unit - basic	\$ 0.04	\$ 0.00	\$ 0.08	\$ 0.01	\$ 0.38	\$ 0.27	\$ 0.45	\$ 0.33
- diluted	\$ 0.04	\$ 0.00	\$ 0.08	\$ 0.01	\$ 0.38	\$ 0.27	\$ 0.45	\$ 0.32
Funds from operations	\$ 62,634	\$ 65,645	\$ 62,737	\$ 63,110	\$ 42,281	\$ 46,630	\$ 60,906	\$ 55,575
Distributions declared	\$ 52,096	\$ 50,206	\$ 58,791	\$ 60,498	\$ 53,498	\$ 44,459	\$ 43,265	\$ 43,069
Payout ratio (%)	83%	76%	94%	96%	127%	95%	71%	77%

The table above highlights the Fund's performance for the second quarter of 2007 and also for the preceding seven quarters. During 2005 and early 2006, production continued to experience normal declines until a more significant decrease occurred in the first quarter of 2006 due to a one-time adjustment for several payout wells, restricted production on wells in Chip Lake and Nevis, and some minor non-core property dispositions that occurred in 2005. Production increased in the second quarter of 2006 with the addition of eight days of production from the Ketch properties and further increased in the third quarter of 2006 as the acquisition was fully integrated with Advantage. Production in the second quarter of 2007 temporarily decreased as expected due to several facility turnarounds that had been planned for the period. Advantage's revenues and funds from operations increased significantly beginning in the third quarter of 2006 primarily due to the production from the merger with Ketch, offset by lower natural gas prices. Net income has been lower during the last four quarters due to reduced natural gas prices realized during the periods, amortization of the management internalization consideration and increased depletion and depreciation expense due to the Ketch merger. During 2006, the payout ratio was higher relative to prior quarters as a result of considerably weak natural gas prices relative to the distribution level. Additionally, the timing of the Ketch merger significantly increased the payout ratio for the second quarter of 2006 as the arrangement closed prior to the June record date resulting in the payment of a full month distribution to Ketch Unitholders whereas funds from operations for June only included eight days of cash flows from the Ketch properties. The payout ratio in the first and second quarters of 2007 are lower as we reduced the distribution level in January 2007 to reflect current commodity prices.

Critical Accounting Estimates

The preparation of financial statements in accordance with GAAP requires Management to make certain judgments and estimates. Changes in these judgments and estimates could have a material impact on the Fund's financial results and financial condition. Management relies on the estimate of reserves as prepared by the Fund's independent qualified reserves evaluator. The process of estimating reserves is critical to several accounting estimates. The process of estimating reserves is complex and requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development and production activities becomes available and as economic conditions impact crude oil and natural gas prices, operating costs, royalty burden changes, and future development costs. Reserve estimates impact net income through depletion and depreciation of property and equipment, the provision for asset retirement costs and related accretion expense, and impairment calculations for fixed assets and goodwill. The reserve estimates are also used to assess the

borrowing base for the Fund's credit facilities. Revision or changes in the reserve estimates can have either a positive or a negative impact on net income and the borrowing base of the Fund.

Controls and Procedures

The Fund has established procedures and internal control systems to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Management of the Fund is committed to providing timely, accurate and balanced disclosure of all material information about the Fund. Disclosure controls and procedures are in place to ensure all ongoing reporting requirements are met and material information is disclosed on a timely basis. The Chief Executive Officer and Vice-President Finance and Chief Financial Officer, individually, sign certifications that the financial statements, together with the other financial information included in the regular filings, fairly present in all material respects the financial condition, results of operations, and cash flows as of the dates and for the periods presented in the filings. The certifications further acknowledge that the filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the filings. During the second quarter of 2007, there were no significant changes that would materially affect, or are reasonably likely to materially affect, the internal controls over financial reporting.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation. Further, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Outlook

The Fund has established a 2007 Budget, as approved by the Board of Directors, that retains a high degree of activity and will focus on drilling in many of our key properties where a high level of success was realized through 2006. Capital will also be directed to accommodate facility expansions and further develop enhanced recovery schemes as necessary. New drill bit additions are expected to be more effective in replacing production as corporate declines have continued to subside through the first quarter of 2007. Advantage's production now contains very little flush production from high impact wells and concentrated drilling programs (from 2004 and 2005 activities) creating a balanced and predictable platform.

During the second quarter of 2007, we expected and realized a significant impact to our production due to a major third party plant turnaround. This was exacerbated by prolonged wet weather throughout the spring which affected new well tie-ins and routine well servicing. The reduced capital activity in the second quarter will affect the third quarter of 2007. We also expect another major third party plant turnaround to occur which will significantly affect our Lookout Butte property. These turnarounds combined with well payouts are expected to result in an impact of approximately 400 boe/d to the 2007 annual average production. Overall, we expect production in 2007 to trend toward the lower end of our guidance of 27,500 to 29,500 boe/d.

Advantage's 2007 capital expenditures budget of \$120 to \$145 million includes the drilling, completion and tie-in of 107 gross wells (64 net). For the remainder of 2007, our capital program will be directed mainly at oil opportunities due to the continued strong commodity prices. At Sunset, in Northern Alberta, four light oil wells are planned to follow-up the successful 2006 development drilling program and capital will also be required to expand water flood facilities in this light oil pool. In Central Alberta, drilling will continue at Nevis for 40 degree light oil where horizontal drilling in 2006 and early 2007 showed excellent results. A net 15 sections of land were added through deals with industry third parties in 2006 bringing the total land under control to 37.5 net sections in this property. A second development drilling program in the western portion of the Nevis property is underway and facilities will be constructed to accommodate production additions. Additional gas opportunities will be pursued in the Central Alberta areas targeting down spacing and follow-up to successes. In Southern Alberta and Southeast Saskatchewan, 13 wells (10 net) will be drilled for oil targets in 2007.

Per unit operating costs are forecasted to be closer to the \$10.50 to \$11.50/boe range. Higher property taxes, surface rentals and additional trucking costs due to continued pipeline restrictions in Southeast Saskatchewan are expected to continue in 2007. We experienced a 6% reduction in the per unit costs and an 11% reduction in total operating costs when comparing Q2 to Q1 2007. However, the per unit cost reduction is partly offset by lower production volumes in Q2 due to the wet weather and third party outages. Advantage is undertaking several operating cost reduction initiatives throughout 2007 to help offset these increases and we have begun to realize some key achievements in this area.

Advantage's funds from operations in 2007 will continue to be impacted by the volatility of crude oil and natural gas prices and the \$US/\$Canadian exchange rate. Advantage will continue to follow its strategy of acquiring properties that provide low risk

development opportunities and enhance long-term cash flow. Advantage will also continue to focus on low cost production and reserve additions through low to medium risk development drilling opportunities that have arisen as a result of the acquisitions completed in prior years and from the significant inventory of drilling opportunities that has resulted from the Ketch merger. The synergy of larger size and the complementary winter/summer drilling programs with the Ketch merger is providing benefits in terms of securing services, flexibility and quality of our capital program.

Looking forward, Advantage's high quality assets, three year drilling inventory, hedging program and excellent tax pools provides many options for the Fund and we are committed to maximizing value generation for our Unitholders.

Additional Information

Additional information relating to Advantage can be found on SEDAR at www.sedar.com and the Fund's website at www.advantageincome.com. Such other information includes the annual information form, the annual information circular – proxy statement, press releases, material contracts and agreements, and other financial reports. The annual information form will be of particular interest for current and potential Unitholders as it discusses a variety of subject matter including the nature of the business, structure of the Fund, description of our operations, general and recent business developments, risk factors, reserves data and other oil and gas information.

August 14, 2007

CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Balance Sheets

(thousands of dollars)	June 30, 2007 (unaudited)	December 31, 2006
Assets		
Current assets		
Accounts receivable	\$ 68,200	\$ 79,537
Prepaid expenses and deposits	15,983	16,878
Derivative asset (note 9)	8,139	9,840
	92,322	106,255
Deposit on property acquisition	-	1,410
Derivative asset (note 9)	391	593
Fixed assets (note 2)	1,725,315	1,753,058
Goodwill	120,271	120,271
	\$ 1,938,299	\$ 1,981,587
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	\$ 75,344	\$ 116,109
Distributions payable to Unitholders	17,414	18,970
Current portion of capital lease obligations (note 3)	1,466	2,527
Current portion of convertible debentures (note 4)	1,471	1,464
	95,695	139,070
Capital lease obligations (note 3)	3,429	305
Bank indebtedness (note 5)	377,812	410,574
Convertible debentures (note 4)	172,011	170,819
Asset retirement obligations	36,014	34,324
Future income taxes (note 6)	45,608	61,939
	730,569	817,031
Unitholders' Equity		
Unitholders' capital (note 7)	1,732,693	1,592,758
Convertible debentures equity component (note 4)	8,041	8,041
Contributed surplus (note 7)	1,532	863
Accumulated deficit (note 8)	(534,536)	(437,106)
	1,207,730	1,164,556
	\$ 1,938,299	\$ 1,981,587

Commitments (note 10)

Subsequent Event (note 11)

see accompanying Notes to Consolidated Financial Statements

**Consolidated Statements of Income,
Comprehensive Income and Accumulated Deficit**

(thousands of dollars, except for per Trust Unit amounts) (unaudited)	Three months ended June 30, 2007	Three months ended June 30, 2006	Six months ended June 30, 2007	Six months ended June 30, 2006
Revenue				
Petroleum and natural gas	\$ 125,131	\$ 80,766	\$ 254,403	\$ 167,667
Realized gain (loss) on derivatives (note 9)	(56)	-	6,174	-
Unrealized gain (loss) on derivatives (note 9)	10,126	532	(1,903)	532
Royalties, net of Alberta Royalty Credit	(22,749)	(13,822)	(48,914)	(30,162)
	112,452	67,476	209,760	138,037
Expenses				
Operating	26,919	15,673	57,189	30,739
General and administrative	4,232	2,420	8,948	4,386
Unit-based compensation (note 7)	629	-	629	-
Management fee	-	55	-	887
Performance incentive	-	(300)	-	2,380
Management internalization (note 7)	5,350	524	10,719	524
Interest	5,005	3,940	10,192	7,133
Interest and accretion on convertible debentures	3,898	2,705	7,735	5,511
Depletion, depreciation and accretion	61,365	33,164	125,283	63,187
	107,398	58,181	220,695	114,747
Income (loss) before taxes and non-controlling interest	5,054	9,295	(10,935)	23,290
Future income tax expense (reduction)	280	(14,917)	(16,331)	(17,444)
Income and capital taxes	243	307	524	836
	523	(14,610)	(15,807)	(16,608)
Net income before non-controlling interest	4,531	23,905	4,872	39,898
Non-controlling interest	-	-	-	29
Net income and comprehensive income	4,531	23,905	4,872	39,869
Accumulated deficit, beginning of period	(486,971)	(298,169)	(437,106)	(269,674)
Distributions declared	(52,096)	(53,498)	(102,302)	(97,957)
Accumulated deficit, end of period	\$(534,536)	\$(327,762)	\$(534,536)	\$(327,762)
Net income per Trust Unit (note 7)				
Basic	\$ 0.04	\$ 0.38	\$ 0.04	\$ 0.66
Diluted	\$ 0.04	\$ 0.38	\$ 0.04	\$ 0.65

see accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Cash Flows

(thousands of dollars) (unaudited)	Three months ended June 30, 2007	Three months ended June 30, 2006	Six months ended June 30, 2007	Six months ended June 30, 2006
Operating Activities				
Net income	\$ 4,531	\$ 23,905	\$ 4,872	\$ 39,869
Add (deduct) items not requiring cash:				
Unrealized loss (gain) on derivatives	(10,126)	(532)	1,903	(532)
Unit-based compensation	629	-	629	-
Performance incentive	-	(300)	-	2,380
Management internalization	5,350	524	10,719	524
Accretion on convertible debentures	605	437	1,204	898
Depletion, depreciation and accretion	61,365	33,164	125,283	63,187
Future income taxes	280	(14,917)	(16,331)	(17,444)
Non-controlling interest	-	-	-	29
Expenditures on asset retirement	302	(414)	(3,707)	(1,447)
Changes in non-cash working capital	(13,004)	2,874	(24,120)	(2,843)
Cash provided by operating activities	49,932	44,741	100,452	84,621
Financing Activities				
Units issued, net of costs (note 7)	386	473	104,486	473
Increase (decrease) in bank indebtedness	23,369	33,195	(32,762)	59,496
Reduction of capital lease obligations	(1,719)	(183)	(2,070)	(271)
Distributions to Unitholders	(39,767)	(44,693)	(79,305)	(88,747)
Cash used in financing activities	(17,731)	(11,208)	(9,651)	(29,049)
Investing Activities				
Expenditures on property and equipment	(25,678)	(27,782)	(75,374)	(48,771)
Property acquisitions	-	-	(12,851)	-
Property dispositions	-	-	427	-
Acquisition of Ketch Resources Trust	-	(10,236)	-	(10,236)
Changes in non-cash working capital	(6,523)	4,485	(3,003)	3,435
Cash used in investing activities	(32,201)	(33,533)	(90,801)	(55,572)
Net change in cash	-	-	-	-
Cash, beginning of period	-	-	-	-
Cash, end of period	\$ -	\$ -	\$ -	\$ -
Supplementary Cash Flow Information				
Interest paid	\$ 10,171	\$ 9,049	\$ 17,176	\$ 15,692
Taxes paid	\$ 469	\$ 741	\$ 830	\$ 1,270

see accompanying Notes to Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

June 30, 2007 (unaudited)

All tabular amounts in thousands except for Trust Units and per Trust Unit amounts

The interim consolidated financial statements of Advantage Energy Income Fund (“Advantage” or the “Fund”) have been prepared by management in accordance with Canadian generally accepted accounting principles using the same accounting policies as those set out in note 2 to the consolidated financial statements for the year ended December 31, 2006, except as described below. The interim consolidated financial statements should be read in conjunction with the audited consolidated financial statements of Advantage for the year ended December 31, 2006 as set out in Advantage’s Annual Report.

1. Changes in Accounting Policies

(a) Financial Instruments

Effective January 1, 2007, the Fund adopted CICA Handbook sections 3855 “Financial Instruments - Recognition and Measurement”, 3862 “Financial Instruments – Disclosures”, 3863 “Financial Instruments – Presentation”, and 3865 “Hedges”.

Section 3855 “Financial Instruments - Recognition and Measurement” establishes criteria for recognizing and measuring financial instruments including financial assets, financial liabilities and non-financial derivatives. Under this standard, all financial instruments must initially be recognized at fair value on the balance sheet. Measurement of financial instruments subsequent to the initial recognition, as well as resulting gains and losses, are recorded based on how each financial instrument was initially classified. The Fund has classified each identified financial instrument into the following categories: held for trading, loans and receivables, held to maturity investments, available for sale financial assets, and other financial liabilities. Held for trading financial instruments are measured at fair value with gains and losses recognized in earnings immediately. Available for sale financial assets are measured at fair value with gains and losses, other than impairment losses, recognized in other comprehensive income and transferred to earnings when the asset is derecognized. Loans and receivables, held to maturity investments and other financial liabilities are recognized at amortized cost using the effective interest method and impairment losses are recorded in earnings when incurred. Upon adoption and with all new financial instruments, an election is available that allows entities to classify any financial instrument as held for trading. Only those financial assets and liabilities that must be classified as held for trading by the standard have been classified as such by the Fund. As the Fund frequently utilizes non-financial derivative instruments to manage market risk associated with volatile commodity prices, such instruments must be classified as held for trading and recorded on the balance sheet at fair value as derivative assets and liabilities. Section 3865 “Hedges” provides an alternative to recognizing gains and losses on derivatives in earnings if the instrument is designated as part of a hedging relationship and meets the necessary criteria. Under the alternative hedge accounting treatment, gains and losses on derivatives classified as effective hedges are included in other comprehensive income until the time at which the hedged item is realized. The Fund does not utilize derivative instruments for speculative purposes but has elected not to apply hedge accounting. Therefore, gains and losses on these instruments are recorded as unrealized gains and losses on derivatives in the consolidated statement of income, comprehensive income and accumulated deficit in the period they occur and as realized gains and losses on derivatives when the contracts are settled. Since unrealized gains and losses on derivatives are non-cash items, there is no impact on the statement of cash flows as a result of their recognition.

In some instances, derivative financial instruments can be embedded within other contracts. Embedded derivatives within a host contract must be recorded separately from the host contract when their economic characteristics and risks are not clearly and closely related to those of the host contract, the terms of the embedded derivatives are the same as those of a freestanding derivative, and the combined contract is not classified as held for trading or designated at fair value. The Fund selected January 1, 2003, as its accounting transition date for any potential embedded derivatives and has not identified any embedded derivatives that would require separation from the host contract and fair value accounting.

Transaction costs are frequently attributed to the acquisition or issue of a financial asset or liability. Section 3855 requires that such transaction costs incurred on held for trading financial instruments be expensed immediately. For other financial instruments, an entity can adopt an accounting policy of either expensing transaction costs as they occur or adding such transaction costs to the fair value of the financial instrument. The Fund has chosen a policy of adding transaction costs to the fair value initially recognized for financial assets and liabilities that are not classified as held for trading.

The Fund has adopted the new standards prospectively as required which allows amendments to the carrying values of financial instruments, effective as of the adoption date, to be recognized as an adjustment to the beginning balance of accumulated deficit. As the new standards have not resulted in any significant changes to the recognition and measurement of the Fund’s financial instruments, no adjustment to accumulated deficit was required. The new standards also require several additional disclosures in the notes to the financial statements. Among the disclosures required, the Fund must disclose the exposure to various risks associated with financial instruments and the policies that exist to manage these risks.

(b) Comprehensive Income

Effective January 1, 2007, the Fund adopted CICA Handbook section 1530 “Comprehensive Income”. The Fund has adopted this section retroactively and there were no changes to prior periods. Comprehensive income consists of net income and other comprehensive income (“OCI”) with amounts included in OCI shown net of tax. Accumulated other comprehensive income is a new equity category comprised of the cumulative amounts of OCI. To date, the Fund does not have any adjustments in OCI and therefore comprehensive income is currently equal to net income.

(c) Accounting Changes

Effective January 1, 2007, the Fund adopted the revised recommendations of CICA section 1506 “Accounting Changes”. The new recommendations permit voluntary changes in accounting policy only if they result in financial statements which provide more reliable and relevant information. Accounting policy changes are applied retrospectively unless it is impractical to determine the period or cumulative impact of the change. Corrections of prior period errors are applied retrospectively and changes in accounting estimates are applied prospectively by including the changes in earnings. The guidance was effective for all changes in accounting polices, changes in accounting estimates and corrections of prior period errors initiated in periods beginning on or after January 1, 2007.

(d) Recent Accounting Pronouncements Issued But Not Implemented

The CICA has issued section 1535 “Capital Disclosures”, which will be effective January 1, 2008 for the Fund. Section 1535 will require the Fund to provide additional disclosures relating to capital and how it is managed. It is not anticipated that the adoption of section 1535 will impact the amounts reported in the Fund’s financial statements as they primarily relate to disclosure.

(e) Comparative Figures

Certain comparative figures have been reclassified to conform to the current year’s presentation.

2. Fixed Assets

June 30, 2007	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	\$ 2,421,038	\$ 700,256	\$1,720,782
Furniture and equipment	8,445	3,912	4,533
	\$ 2,429,483	\$ 704,168	\$1,725,315

December 31, 2006	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	\$ 2,324,948	\$ 576,707	\$1,748,241
Furniture and equipment	8,175	3,358	4,817
	\$ 2,333,123	\$ 580,065	\$1,753,058

During the six months ended June 30, 2007, Advantage capitalized general and administrative expenditures and unit-based compensation directly related to exploration and development activities of \$3,943,000 (June 30, 2006 - \$1,775,000).

3. Capital Lease Obligations

The Fund has capital leases on a variety of fixed assets. Future minimum lease payments at June 30, 2007 consist of the following:

2007	\$ 1,002
2008	1,079
2009	773
2010	773
2011	1,925
	<hr/> 5,552
Less amounts representing interest	(657)
	<hr/> 4,895
Current portion	(1,466)
	<hr/> \$ 3,429 <hr/>

During the quarter ended June 30, 2007, Advantage entered a new lease arrangement that resulted in the recognition of a fixed asset addition and capital lease obligation of \$4.1 million. The lease obligation bears interest at 5.8% and is secured by the related equipment. The lease term expires June 2011 with a final purchase obligation of \$1.5 million at which time ownership of the equipment will transfer to Advantage.

The amortization of fixed assets subject to capital leases is recorded in depletion and depreciation expense.

4. Convertible Debentures

The convertible unsecured subordinated debentures pay interest semi-annually and are convertible at the option of the holder into Trust Units of Advantage at the applicable conversion price per Trust Unit plus accrued and unpaid interest. The details of the convertible debentures including fair market values initially assigned and issuance costs are as follows:

	10.00%	9.00%	8.25%	7.75%	7.50%	6.50%	Total
Issue date	Oct. 18, 2002	July 8, 2003	Dec. 2, 2003	Sep. 15, 2004	Sep. 15, 2004	May 18, 2005	
Maturity date	Nov. 1, 2007	Aug. 1, 2008	Feb. 1, 2009	Dec. 1, 2011	Oct. 1, 2009	June 30, 2010	
Conversion price	\$ 13.30	\$ 17.00	\$ 16.50	\$ 21.00	\$ 20.25	\$ 24.96	
Liability component	\$ 52,722	\$ 28,662	\$ 56,802	\$ 47,444	\$ 71,631	\$ 66,981	\$ 324,242
Equity component	2,278	1,338	3,198	2,556	3,369	2,971	15,710
Gross proceeds	55,000	30,000	60,000	50,000	75,000	69,952	339,952
Issuance costs	(2,495)	(1,444)	(2,588)	(2,190)	(3,190)	-	(11,907)
Net proceeds	\$ 52,505	\$ 28,556	\$ 57,412	\$ 47,810	\$ 71,810	\$ 69,952	\$ 328,045

The convertible debentures are redeemable prior to their maturity dates, at the option of the Fund, upon providing 30 to 60 days advance notification. The redemption prices for the various debentures, plus accrued and unpaid interest, is dependent on the redemption periods and are as follows:

Convertible Debenture	Redemption Periods	Redemption Price
10.00%	After November 1, 2006 and before November 1, 2007	\$1,025
9.00%	After August 1, 2006 and on or before August 1, 2007 After August 1, 2007 and before August 1, 2008	\$1,050 \$1,025
8.25%	After February 1, 2007 and on or before February 1, 2008 After February 1, 2008 and before February 1, 2009	\$1,050 \$1,025
7.75%	After December 1, 2007 and on or before December 1, 2008 After December 1, 2008 and on or before December 1, 2009 After December 1, 2009 and before December 1, 2011	\$1,050 \$1,025 \$1,000
7.50%	After October 1, 2007 and on or before October 1, 2008 After October 1, 2008 and before October 1, 2009	\$1,050 \$1,025
6.50%	After June 30, 2008 and on or before June 30, 2009 After June 30, 2009 and before June 30, 2010	\$1,050 \$1,025

The balance of debentures outstanding at June 30, 2007 and changes in the liability and equity components during the six months ended June 30, 2007 are as follows:

	10.00%	9.00%	8.25%	7.75%	7.50%	6.50%	Total
Debentures outstanding	\$ 1,480	\$ 5,392	\$ 4,867	\$ 46,766	\$ 52,268	\$ 69,952	\$ 180,725
Liability component:							
Balance at Dec. 31, 2006	\$ 1,464	\$ 5,235	\$ 4,676	\$ 43,765	\$ 49,782	\$ 67,361	\$ 172,283
Accretion of discount	12	48	45	296	441	362	1,204
Converted to Trust Units	(5)	-	-	-	-	-	(5)
Balance at June 30, 2007	\$ 1,471	\$ 5,283	\$ 4,721	\$ 44,061	\$ 50,223	\$ 67,723	\$ 173,482
Equity component:							
Balance at Dec. 31, 2006	\$ 59	\$ 229	\$ 248	\$ 2,286	\$ 2,248	\$ 2,971	\$ 8,041
Converted to Trust Units	-	-	-	-	-	-	-
Balance at June 30, 2007	\$ 59	\$ 229	\$ 248	\$ 2,286	\$ 2,248	\$ 2,971	\$ 8,041

During the six months ended June 30, 2007, \$5,000 debentures (June 30, 2006 - \$24,268,000) were converted resulting in the issuance of 375 Trust Units (June 30, 2006 - 1,282,015 Trust Units).

5. Bank Indebtedness

Advantage has a credit facility agreement with a syndicate of financial institutions which provides for a \$580 million extendible revolving loan facility and a \$20 million operating loan facility. The loan's interest rate is based on either prime, US base rate, LIBOR or bankers' acceptance rates, at the Fund's option, subject to certain basis point or stamping fee adjustments ranging from 0.00% to 1.25% depending on the Fund's debt to cash flow ratio. The credit facilities are secured by a \$1 billion floating charge demand debenture, a general security agreement and a subordination agreement from the Fund covering all assets and cash flows. The credit facilities are subject to review on an annual basis with the last review and renewal completed in June 2007. Various borrowing options are available under the credit facilities, including prime rate-based advances, US base rate advances, US dollar LIBOR advances and bankers' acceptances loans. The credit facilities constitute a revolving facility for a 364 day term which is extendible annually for a further 364 day revolving period at the option of the syndicate. If not extended, the revolving credit facility is converted to a two year term facility with the first payment due one year and one day after commencement of the term. The credit facilities contain standard commercial covenants for facilities of this nature. The only financial covenant is a requirement for Advantage Oil & Gas Ltd. ("AOG") to maintain a minimum cash flow to interest expense ratio of 3.5:1, determined on a rolling four quarter basis. Breach of any covenant will result in an event of default in which case AOG has 20 days to remedy such default. If the default is not remedied or waived, and if required by the majority of lenders, the administrative agent of the lenders has the option to declare all obligations of AOG under the credit facilities to be immediately

due and payable without further demand, presentation, protest, or notice of any kind. Distributions by AOG to the Fund (and effectively by the Fund to Unitholders) are subordinated to the repayment of any amounts owing under the credit facilities. Distributions to Unitholders are not permitted if the Fund is in default of such credit facilities or if the amount of the Fund's outstanding indebtedness under such facilities exceeds the then existing current borrowing base. Interest payments under the debentures are also subordinated to indebtedness under the credit facilities and payments under the debentures are similarly restricted. For the six months ended June 30, 2007, the effective interest rate on the outstanding amounts under the facility was approximately 5.4% (June 30, 2006 - 4.9%).

6. Income Taxes

On June 12, 2007 the Federal government's bill regarding the taxation of distributions from trusts beginning January 1, 2011 received a third reading and on June 22, 2007 received Royal Assent, thus becoming fully enacted. As a result, a net expense of \$5.5 million was recognized in the future income tax provision for the three months ended June 30, 2007.

7. Unitholders' Equity

(a) Unitholders' Capital

(i) Authorized

Unlimited number of voting Trust Units

(ii) Issued

	Number of Units	Amount
Balance at December 31, 2006	105,390,470	\$ 1,618,025
Issued on conversion of debentures	375	5
Issued on exercise of Trust Unit rights	37,500	562
Distribution reinvestment plan	2,076,686	24,553
Issued for cash, net of costs	8,600,000	104,096
Management internalization forfeitures	(14,139)	(286)
	116,090,892	\$ 1,746,955
Management internalization escrowed Trust Units		(14,262)
Balance at June 30, 2007		\$ 1,732,693

On February 14, 2007 Advantage issued 7,800,000 Trust Units, plus an additional 800,000 Trust Units upon exercise of the Underwriters' over-allotment option on March 7, 2007, at \$12.80 per Trust Unit for approximate net proceeds of \$104.1 million (net of Underwriters' fees and other issue costs of \$6.0 million).

During the six months ended June 30, 2007, 2,076,686 Trust Units were issued under the Premium Distribution^(TM), Distribution Reinvestment, and Optional Trust Unit Purchase Plan, generating \$24.6 million reinvested in the Fund.

On June 23, 2006, Advantage internalized the external management contract structure and eliminated all related fees for total original consideration of 1,933,208 Advantage Trust Units initially valued at \$39.1 million and subject to escrow provisions over a 3-year period, vesting one-third each year beginning June 23, 2007. The management internalization consideration is being deferred and amortized into income as management internalization expense over the specific vesting periods during which employee services are provided, including an estimate of future Trust Unit forfeitures. For the six months ended June 30, 2007, a total of 14,139 Trust Units issued for the management internalization were forfeited and \$10.7 million has been recognized as management internalization expense. As at June 30, 2007, 1,204,397 Trust Units remain held in escrow.

(b) Trust Units Rights Incentive Plan

	Series B	
	Number	Price
Balance at December 31, 2006	187,500	\$ 10.97
Exercised	(37,500)	-
Reduction of exercise price	-	(0.90)
Balance at June 30, 2007	150,000	\$ 10.07
Expiration date	June 17, 2008	

(c) Unit-Based Compensation

Advantage's current employee compensation includes a Restricted Trust Unit Plan (the "Plan"), as approved by the Unitholders on June 23, 2006, and Trust Units issuable for the retention of certain employees of the Fund. The purpose of the long-term compensation plans is to retain and attract employees, to reward and encourage performance, and to focus employees on operating and financial performance that result in lasting Unitholder return.

The Plan authorizes the Board of Directors to grant Restricted Trust Units ("RTUs") to directors, officers, or employees of the Fund. The number of RTUs granted is based on the Fund's Trust Unit return for a calendar year and compared to a peer group approved by the Board of Directors. The Trust Unit return is calculated at the end of the year and is primarily based on the year-over-year change in the Trust Unit price plus distributions. The RTU grants vest one third immediately on grant date, with the remaining two thirds vesting evenly on the following two yearly anniversary dates. The holders of RTUs may elect to receive cash upon vesting in lieu of the number of Trust Units to be issued, subject to consent of the Fund. Compensation cost related to the Plan is based on the "fair value" of the RTUs at the grant date and is recognized as compensation expense over the service period. This valuation incorporates the period end Trust Unit price, the estimated number of RTUs to vest, and certain management estimates. The maximum fair value of RTUs granted in any one calendar year is limited to 175% of the base salaries of those individuals participating in the Plan for such period. No RTUs have been granted under the Plan at this time and accordingly, no compensation expense relating to the RTUs has been recognized in the interim financial statements. Once the calendar year is completed and the final Trust Unit return is calculated for the return period, RTUs may be granted and consequently, compensation expense may be recognized at that time. As the Fund did not meet the 2006 grant thresholds, there was no RTU grant made for the 2006 year.

For the six months ended June 30, 2007, the Fund has accrued unit-based compensation expense of \$0.6 million and has capitalized \$0.2 million related to Trust Units issuable for the retention of certain employees of the Fund.

(d) Net Income per Trust Unit

The calculation of basic and diluted net income per Trust Unit are derived from both income available to Unitholders and weighted average Trust Units outstanding calculated as follows:

	Three months ended June 30, 2007	Three months ended June 30, 2006	Six months ended June 30, 2007	Six months ended June 30, 2006
Income available to Unitholders				
Basic	\$ 4,531	\$ 23,905	\$ 4,872	\$ 39,869
Exchangeable Shares	-	-	-	29
Diluted	\$ 4,531	\$ 23,905	\$ 4,872	\$ 39,898
Weighted average Trust Units outstanding				
Basic	113,854,335	62,710,027	111,108,403	60,802,526
Trust Units Rights Incentive Plan – Series A	-	83,254	-	83,339
Trust Units Rights Incentive Plan – Series B	43,259	84,205	39,487	95,366
Exchangeable Shares	-	41,693	-	73,500
Management internalization	223,495	-	152,844	-
Diluted	114,121,089	62,919,179	111,300,734	61,054,731

The calculation of diluted net income per Trust Unit excludes all series of convertible debentures for the three and six months ended June 30, 2007 and June 30, 2006 as the impact would be anti-dilutive. There were no Exchangeable Shares remaining in 2007. Total weighted average Trust Units issuable in exchange for the convertible debentures and excluded from the diluted net income per Trust Unit calculation for the three and six months ended June 30, 2007 were 8,334,353 and 8,334,403, respectively (June 30, 2006 – 5,856,596 and 6,009,316, respectively). As at June 30, 2007, the total convertible debentures outstanding were immediately convertible to 8,334,077 Trust Units (June 30, 2006 – 8,339,339).

8. Accumulated Deficit

Accumulated deficit consists of accumulated income and accumulated distributions for the Fund since inception as follows:

	June 30, 2007	December 31, 2006
Accumulated Income	\$ 232,395	\$ 227,523
Accumulated Distributions	(766,931)	(664,629)
Accumulated Deficit	\$ (534,536)	\$ (437,106)

For the six months ended June 30, 2007, the Fund declared \$102.3 million in distributions, representing \$0.90 per distributable Trust Unit (six months ended June 30, 2006 - \$98.0 million representing \$1.50 per distributable Trust Unit).

9. Financial Instruments

Financial instruments of the Fund include accounts receivable, deposits, accounts payable and accrued liabilities, distributions payable to Unitholders, bank indebtedness, convertible debentures and derivative assets and liabilities.

Accounts receivable and deposits are classified as loans and receivables and measured at amortized cost. Accounts payable and accrued liabilities, distributions payable to Unitholders and bank indebtedness are all classified as other liabilities and similarly measured at amortized cost. As at June 30, 2007, there were no significant differences between the carrying amounts reported on the balance sheet and the estimated fair values of these financial instruments due to the short terms to maturity and the floating interest rate on the bank indebtedness.

The Fund has convertible debenture obligations outstanding, of which the liability component has been classified as other liabilities and measured at amortized cost. The convertible debentures have different fixed terms and interest rates (note 4)

resulting in fair values that will vary over time as market conditions change. As at June 30, 2007, the estimated fair value of the total outstanding convertible debenture obligation was \$181.9 million (December 31, 2006 - \$180.0 million). The fair value of the liability component of convertible debentures was determined based on a discounted cash flow model assuming no future conversions and continuation of current interest and principal payments. The Fund applied discount rates of between 7 and 8% considering current available market information, assumed credit adjustments, and various terms to maturity.

Advantage has an established hedging strategy and manages the risk associated with changes in commodity prices by entering into derivatives, which are recorded at fair value as derivative assets and liabilities with gains and losses recognized through earnings. As the fair value of the contracts varies with commodity prices, they give rise to financial assets and liabilities. The fair value of the derivatives are determined through valuation models completed by third parties. Various assumptions based on current market information were used in these valuations, including settled forward commodity prices, interest rates, foreign exchange rates, volatility and other relevant factors. The actual gains and losses realized on eventual cash settlement can vary materially due to subsequent fluctuations in commodity prices as compared to the valuation assumptions.

Credit Risk

Accounts receivable, deposits, and derivative assets are subject to credit risk exposure and the carrying values reflect Management's assessment of the associated maximum exposure to such credit risk. Substantially all of the Fund's accounts receivable are due from customers and joint operation partners concentrated in the Canadian oil and gas industry. As such, accounts receivable are subject to normal industry credit risks. Advantage mitigates such credit risk by closely monitoring significant counterparties and dealing with a broad selection of partners that diversify risk within the sector. The Fund's deposits are primarily due from the Alberta Provincial government and are viewed by Management as having minimal associated credit risk. To the extent that Advantage enters derivatives to manage commodity price risk, it may be subject to credit risk associated with counterparties with which it contracts. Credit risk is mitigated by entering into contracts with only stable, creditworthy parties and through frequent reviews of exposures to individual entities. In addition, the Fund generally enters into derivative contracts with investment grade institutions that are members of Advantage's credit facility syndicate to further mitigate associated credit risk.

Liquidity Risk

The Fund is subject to liquidity risk attributed from accounts payable and accrued liabilities, distributions payable to Unitholders, bank indebtedness, convertible debentures, and derivative liabilities. Accounts payable and accrued liabilities, distributions payable to Unitholders and derivative liabilities are all due within one year of the balance sheet date and Advantage does not anticipate any problems in satisfying the obligations due to the strength of funds from operations and the existing credit facility. The Fund's bank indebtedness is subject to a \$600 million credit facility agreement which mitigates liquidity risk by enabling Advantage to manage interim cash flow fluctuations. The credit facility constitutes a revolving facility for a 364 day term which is extendible annually for a further 364 day revolving period at the option of the syndicate. If not extended, the revolving credit facility is converted to a two year term facility with the first payment due one year and one day after commencement of the term. The terms of the credit facility are such that it provides Advantage adequate flexibility to evaluate and assess liquidity issues if and when they arise. Additionally, the Fund regularly monitors liquidity related to obligations by evaluating forecasted cash flows, optimal debt levels, capital spending activity, working capital requirements, and other potential cash expenditures. This continual financial assessment process further enables the Fund to mitigate liquidity risk.

Advantage has several series of convertible debentures outstanding that mature from 2007 to 2011 (note 4). Interest payments are made semi-annually with excess funds from operating activities. As the debentures become due, the Fund can satisfy the obligations in cash or issue Trust Units at a price determined in the applicable debenture agreements. This settlement option allows the Fund to adequately manage liquidity, plan available cash resources and implement an optimal capital structure.

To the extent that Advantage enters derivatives to manage commodity price risk, it may be subject to liquidity risk as derivative liabilities become due. While the Fund has elected not to follow hedge accounting, derivative instruments are not entered for speculative purposes and Management closely monitors existing commodity risk exposures. As such, liquidity risk is mitigated since any losses actually realized are subsidized by increased cash flows realized from the higher commodity price environment.

Interest Rate Risk

The Fund is exposed to interest rate risk to the extent that bank indebtedness is at a floating rate of interest and the Fund's maximum exposure to interest rate risk is based on the effective interest rate and the current carrying value of the bank indebtedness. The Fund monitors the interest rate markets to ensure that appropriate steps can be taken if interest rate volatility compromises the Fund's cash flows. A 1% interest rate fluctuation for the six months ended June 30, 2007 could potentially have impacted interest expense by approximately \$1.9 million for that period.

Price and Currency Risk

Advantage's derivative assets and liabilities are subject to both price and currency risks as their fair values are based on assumptions including forward commodity prices and foreign exchange rates. The Fund enters derivative financial instruments to manage commodity price risk exposure relative to actual commodity production and does not utilize derivative instruments for speculative purposes. Changes in the price assumptions can have a significant effect on the fair value of the derivative assets and liabilities and thereby impact net income. It is estimated that a 10% change in the forward natural gas prices used to calculate the fair value of the natural gas derivatives at June 30, 2007 could impact net income by approximately \$2.5 million for the six months ended June 30, 2007. As well, a change of 10% in the forward crude oil prices used to calculate the fair value of the crude oil derivatives at June 30, 2007 could impact net income by \$0.1 million for the six months ended June 30, 2007. A change of 10% in the forward power prices used to calculate the fair value of the power derivatives at June 30, 2007 could impact net income by \$0.2 million for the six months ended June 30, 2007. A similar change in the currency rate assumption underlying the derivatives fair value does not have a material impact on net income.

As at June 30, 2007 the Fund had the following derivatives in place:

Description of Derivative	Term	Volume	Average Price
Natural gas - AECO			
Fixed price	April 2007 to October 2007	9,478 mcf/d	Cdn\$7.16/mcf
Fixed price	April 2007 to October 2007	9,478 mcf/d	Cdn\$7.55/mcf
Fixed price	November 2007 to March 2008	7,109 mcf/d	Cdn\$9.54/mcf
Collar	November 2007 to March 2008	9,478 mcf/d	Floor Cdn\$8.44/mcf Ceiling Cdn\$10.29/mcf
Collar	November 2007 to March 2008	7,109 mcf/d	Floor Cdn\$8.70/mcf Ceiling Cdn\$10.71/mcf
Crude oil - WTI			
Collar	October 2006 to September 2007	1,000 bbls/d	Floor US\$65.00/bbl Ceiling US\$90.00/bbl
Electricity – Alberta Pool Price			
Fixed price	April 2006 to December 2007	0.5 MW	Cdn\$60.79/MWh
Fixed price	January 2007 to December 2007	3.0 MW	Cdn\$56.00/MWh
Fixed price	January 2008 to December 2008	3.0 MW	Cdn\$54.00/MWh

As at June 30, 2007 the fair value of the derivatives outstanding was an asset of approximately \$8,530,000 (December 31, 2006 – \$10,433,000). For the six months ended June 30, 2007 \$1,903,000 was recognized in income as an unrealized derivative loss (June 30, 2006 - \$532,000 unrealized derivative gain) and \$6,174,000 was recognized in income as a realized derivative gain (June 30, 2006 – nil).

In addition, the Fund has the following physical natural gas contracts in place with gains and losses recognized in earnings as the contracts settle:

Description of Physical Contract	Term	Volume	Average Price
Natural gas - AECO			
Collar	April 2007 to October 2007	4,739 mcf/d	Floor Cdn\$7.12/mcf Ceiling Cdn\$8.67/mcf
Collar	April 2007 to October 2007	4,739 mcf/d	Floor Cdn\$6.86/mcf Ceiling Cdn\$9.13/mcf
Collar	April 2007 to October 2007	9,478 mcf/d	Floor Cdn\$7.39/mcf Ceiling Cdn\$9.63/mcf
Collar	April 2007 to October 2007	9,478 mcf/d	Floor Cdn\$6.33/mcf Ceiling Cdn\$7.20/mcf

10. Commitments

Advantage has lease commitments relating to office buildings. The estimated annual minimum operating lease rental payments for the buildings are as follows:

2007	\$ 1,116
2008	1,385
2009	779
2010	779
2011	195
	<hr/>
	\$ 4,254
	<hr/>

11. Subsequent Event

On July 9, 2007, the Fund and Sound Energy Trust (“Sound”) announced that their respective boards of directors had unanimously approved an agreement for the business combination of Advantage and Sound. The combined trust will continue to operate under the name Advantage Energy Income Fund and will be led by the existing Advantage management team. Successful completion of the business combination is subject to stock exchange, court and regulatory approvals and the approval by at least two-thirds of Sound’s Unitholders and Sound Exchangeable Shareholders. It is anticipated that the Sound Unitholder meeting required to approve the Arrangement will be held, and the Arrangement is expected to close, in early September 2007, and that Sound Unitholders will receive Advantage’s September distribution payable on October 15, 2007.

The combination will be accomplished through a Plan of Arrangement (the “Arrangement”) by the exchange of each Sound Trust Unit for 0.30 of an Advantage Trust Unit or, at the election of the holder of Sound Trust Units, \$0.66 in cash and 0.2557 of an Advantage Trust Unit. In addition, all Sound Exchangeable Shares will be exchanged for Advantage Trust Units on the same ratio based on the conversion ratio in effect at the effective date of the Arrangement. The acquisition will be accounted for using the purchase method whereby the assets acquired and liabilities assumed are recorded at their fair values with the excess of the aggregate consideration over the fair value of the identifiable net assets allocated to goodwill, if applicable.

The Arrangement prohibits Sound from soliciting or initiating any discussion regarding any other business combination or sale of material assets, contains provisions to Advantage to match competing, unsolicited proposals and, subject to certain conditions, provides for a \$12 million termination fee payable to Advantage.

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Sheila O'Brien⁽³⁾
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Steven Sharpe⁽³⁾
Rodger A. Tourigny⁽¹⁾⁽³⁾

⁽¹⁾ Member of Audit Committee

⁽²⁾ Member of Reserve Evaluation Committee

⁽³⁾ Member of Human Resources, Compensation & Corporate Governance Committee

Officers

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Andy J. Mah, President and COO
Patrick J. Cairns, Senior Vice President
Gary F. Bourgeois, Vice President, Corporate Development
Peter A. Hanrahan, Vice President, Finance & CFO
David Cronkhite, Vice President, Operations
Weldon M. Kary, Vice President, Geosciences and Land
Neil Bokenfohr, Vice President, Exploitation

Corporate Secretary

Jay P. Reid, Partner
Burnet, Duckworth and Palmer LLP

Operating Company

Advantage Oil & Gas Ltd.

Auditors

KPMG LLP

Bankers

The Bank of Nova Scotia
National Bank of Canada
Bank of Montreal
Royal Bank of Canada
Canadian Imperial Bank of Commerce
Union Bank of California, Canada Branch
Société Générale, Canada Branch
Alberta Treasury Branches

Independent Reserve Evaluators

Sproule Associates Limited

Legal Counsel

Burnet, Duckworth and Palmer LLP

Abbreviations

bbls - barrels
bbls/d - barrels per day
boe - barrels of oil equivalent (6 mcf = 1 bbl)
boe/d - barrels of oil equivalent per day
bcf - billion cubic feet
mcf - thousand cubic feet
mcf/d - thousand cubic feet per day
mmcf - million cubic feet
mmcf/d - million cubic feet per day
gj - gigajoules
NGLs - natural gas liquids
WTI - West Texas Intermediate
TM - denotes trademark of Canaccord Capital Corporation

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Toronto Stock Exchange Trading Symbols

Trust Units: AVN.UN
10% Convertible Debentures: AVN.DB
9% Convertible Debentures: AVN.DBA
8.25% Convertible Debentures: AVN.DBB
7.5% Convertible Debentures: AVN.DBC
7.75% Convertible Debentures: AVN.DBD
6.50% Convertible Debentures: AVN.DBE

New York Stock Exchange Trading Symbol

Trust Units: AAV