

March 6, 2007

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Dear Mr. Wells & Ms. Beaudoin:

Below please find our comments on National Policy 41-201. We appreciate your work in this area and overall endorse your efforts. As you are aware the CICA has published a Draft Interpretive Release "Distributable Cash in Income Trusts and Other Flow-Through Entities" with comments open to March 31, 2007. We would recommend you extend dialogue period on this policy 41-201 in attempts to have the basic premises agreed to amongst the CSA, the CICA, and participating income funds.

- 1.1 - Expand to state the disclosure is consistent with that required of corporate issuers in similar transactions.
- 1.6 - The description of arm's length and non-arm's length transactions is very useful. This distinction may address our concerns in sections 4.4 and 4.5 noted later.
- 2.1 - We believe that for oil and gas energy trusts the major financial figures that are useful to investors are the GAAP measure of net income, and the non-GAAP measure "Cash Flow"⁽¹⁾. By standardizing the non-GAAP "distributable cash" amount we believe it would place undue credibility on this amount and as such be misleading to investors. We have completely eliminated the usage of the term "distributable cash" in our MD&A disclosure and only refer to actual cash distributions. Attached is a copy of our 2006 year-end press release which we believe achieves the objectives of the CSA's guidance on MDA disclosure for trusts by reconciling cash flow and distributions and discussing the items that may impact future distributions.

(1) Cash flow used in the Canadian oil and gas industry is based on cash flow from operating activities before changes in non-cash working capital and expenditures on site restoration and reclamation.

- 2.2 - This is a key message and understanding that all income fund investors should have. As such we believe “actual cash distributions” should be viewed by trust investors as “dividends” are to investors in corporations. By de-emphasizing cash distributions investors would tend to focus on net income and cash flow to understand the cash generating capabilities of the organization.
- 2.4 - As in 2.2 we believe income trusts should not discuss “cash available for distribution” but rather only “cash distributed” and should describe “distributions” similar to “dividends” and focus on key financial measures such as “net income”, and in sectors such as oil and gas the non-GAAP measure “cash flow”.
- 2.5 - Same comments as 2.4
- 2.7 - We concur a reconciliation of cash distributed to cash flows is very useful and would substitute the words “cash distributed” for “distributable cash” in revising section 2.7.

4.5.2 and 4.4 and 4.5 in general.

We understand and agree with your concerns in this area. However we have the concern that “normal” acquisitions in the oil and gas industry may be unintentionally subject to these sections. Numerous transactions have occurred where a trust acquires properties from a major energy company. The assets purchased may be in excess of 20% of the net book value of the trust’s assets but still viewed as “minor” assets by the vendor. Currently it is a requirement for the trust to obtain 2 years audited financial operating information from the vendor to include in the trust prospectus. The current rules are very onerous for the trust as the vendor may not allocate all costs to this “minor” property.

As such the final wording of sections 4.4 and 4.5 should be reviewed to ensure no representations are required or certificates from vendors in arm’s length purchases by oil and gas trusts. Further that the major energy company would not be considered a “promoter”.

- 6.5.2 - We believe the chart comparing cash flows to actual cash distributions paid and net income to actual cash distributions paid is very useful to investors. Again we endorse the use of wording cash distributions or actual cash distributions and would refrain from the use of the term distributable cash. Please reference your 2006 year-end press release as an example of how we discussed “sustainability” without reference to cash available for distribution.

We would be pleased to further discuss our comments with you at your convenience.

Yours truly,

Signed

Steven W. Sinclair, CA
Senior Vice President, Finance & CFO



NEWS RELEASE
February 22, 2007

ARC ENERGY TRUST ANNOUNCES 2006 FOURTH QUARTER AND YEAR-END FINANCIAL RESULTS

Calgary, February 22, 2007 (AET.UN and ARX – TSX) ARC Energy Trust (“ARC” or “the Trust”) released today its 2006 fourth quarter and year-end financial results.

	Three Months Ended December 31		Twelve Months Ended December 31	
	2006	2005	2006	2005
FINANCIAL				
(\$CDN millions, except per unit and per boe amounts)				
Revenue before royalties	292.5	365.3	1,230.5	1,165.2
Per unit ⁽¹⁾	1.42	1.89	6.02	6.10
Per boe	49.95	67.16	53.46	56.75
Cash flow ⁽²⁾	174.4	207.6	760.6	639.5
Per unit ⁽¹⁾	0.85	1.07	3.72	3.35
Per boe	29.80	38.17	33.05	31.15
Net income	56.6	130.5	460.1	356.9
Per unit ⁽³⁾	0.28	0.68	2.28	1.90
Cash distributions	122.3	115.7	484.2	376.6
Per unit ⁽¹⁾	0.60	0.60	2.40	1.99
Payout ratio ⁽⁴⁾	70%	56%	64%	59%
Net debt outstanding ⁽⁵⁾	739.1	578.1	739.1	578.1
Total capital expenditures and net acquisitions ⁽⁶⁾	214.9	553.6	496.3	865.1
OPERATING				
Production				
Crude oil (bbl/d)	29,605	25,534	29,042	23,282
Natural gas (mmcf/d)	179.5	177.9	179.1	173.8
Natural gas liquids (bbl/d)	4,144	3,943	4,170	4,005
Total (boe per day)	63,663	59,120	63,056	56,254
Average prices				
Crude oil (\$/bbl)	58.26	62.12	65.26	61.11
Natural gas (\$/mcf)	6.99	12.05	6.97	8.96
Natural gas liquids (\$/bbl)	46.51	56.43	52.63	49.91
Oil equivalent (\$/boe) ⁽⁶⁾	49.95	67.16	53.46	56.75
Operating netback (\$/boe)				
Commodity and other revenue (before hedging)	49.95	67.16	53.46	56.75
Transportation costs	(0.64)	(0.65)	(0.63)	(0.70)
Royalties	(8.80)	(13.51)	(9.66)	(11.46)
Operating costs	(9.13)	(7.16)	(8.49)	(6.93)
Netback (before hedging)	31.37	45.84	34.68	37.66
TRUST UNITS				
(thousands)				
Units outstanding, end of period	204,289	202,039	204,289	202,039
Units issuable for exchangeable shares	2,884	2,934	2,884	2,934
Total units outstanding and issuable for exchangeable shares, end of period	207,173	204,973	207,173	204,973
Weighted average units ⁽⁷⁾	203,580	190,510	201,554	188,237
TRUST UNIT TRADING STATISTICS				
(\$CDN, except volumes) based on intra-day trading				
High	29.22	27.58	30.74	27.58
Low	19.20	20.45	19.20	16.55
Close	22.30	26.49	22.30	26.49
Average daily volume (thousands)	1,125	653	706	656

⁽¹⁾ Per unit amounts (with the exception of per unit distributions) are based on weighted average units plus units issuable for exchangeable shares.

⁽²⁾ Management uses cash flow to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow throughout this report are based on cash flow from operating activities before changes in non-cash working capital and expenditures on site restoration and reclamation.

⁽³⁾ Net income per unit is based on net income after non-controlling interest divided by weighted average units (excluding units issuable for exchangeable shares).

⁽⁴⁾ Cash distributions divided by cash flow from operations. This ratio would have increased to 71 per cent and 65 per cent, respectively, for the three and twelve months ended December 31, 2006 if the exchangeable shares had been converted to trust units at the beginning of the period.

⁽⁵⁾ Net debt excludes unrealized commodity and foreign exchange contracts asset and liability.

⁽⁶⁾ Includes other revenue.

⁽⁷⁾ Excludes trust units issuable for outstanding exchangeable shares at period end.

⁽⁸⁾ Includes total consideration for the corporate acquisition including fees but prior to working capital, asset retirement obligation and future income tax liability assumed on acquisition.

ACCOMPLISHMENTS / FINANCIAL UPDATE

- Production averaged 63,056 boe per day in 2006, the highest in the Trust's history and 12 per cent higher than the 56,254 boe per day achieved in 2005. Fourth quarter production reached 63,663 in 2006, an eight per cent increase over the same period in 2005. The increase in annual and fourth quarter production is due primarily to the Redwater and NPCU acquisitions which occurred late in 2005 and several minor acquisitions that closed in 2006. Natural production declines were replaced through a successful and active drilling program. Production per unit increased by seven per cent to 0.31 boe per day per thousand units in 2006, from 0.29 boe per day per thousand units in 2005.
- ARC realized record cash flow from operations of \$760.6 million (\$3.72 per unit) in 2006 compared to \$639.5 million (\$3.35 per unit) in 2005. The 19 per cent increase in 2006 cash flow was due to increased production volumes, cash hedging gains, slightly higher oil prices that offset the impact of lower natural gas prices and higher operating costs. Fourth quarter cash flow decreased by 16 percent from \$207.6 million (\$1.07 per unit) in 2005 to \$174.4 million (\$0.85 per unit) in 2006. The decrease in fourth quarter cash flow was largely attributed to a 42 per cent decrease in ARC's realized gas price compared to the fourth quarter of 2005.
- The Trust posted record net income, before future income taxes and non-controlling interest, of \$379.6 million in 2006 compared to \$364.1 million in 2005. Strong oil prices on average during 2006, combined with record production volume, resulted in revenue of \$1.2 billion, the highest since inception of the Trust. Fourth quarter net income before future income tax and non-controlling interest decreased from \$152.2 million in 2005 to \$61.2 million in 2006. In addition to lower commodity prices, foreign exchange losses, higher depletion expense and a decrease in non-cash gains on commodity and foreign currency contracts contributed to the decrease in net income for the fourth quarter of 2006.
- The Trust declared record cash distributions of \$484.2 million in 2006 (\$2.40 per unit), resulting in a full year payout ratio of 64 per cent. The remaining 36 per cent of 2006 cash flow (\$276.4 million) was used to fund 72 per cent of ARC's capital development program and to contribute \$13.2 million, inclusive of interest income, to the reclamation funds. Fourth quarter distributions were \$122.3 million (\$0.60 per unit) in 2006 compared to \$115.7 million (\$0.60 per unit) in 2005 resulting in a payout ratio of 70 percent in 2006 compared to 56 percent in the fourth quarter of 2005.
- In 2006, the Trust completed its most extensive drilling program to date with 294 gross wells (219 net wells) drilled on operated properties with a 99 per cent success rate. The most significant activity was focused in southeastern Alberta as the Trust drilled 125 net shallow gas wells. In addition, the Trust was active in northern and central Alberta 2006, with the drilling of 61 net wells. In the fourth quarter of 2006 ARC drilled 59 gross wells (45 net wells) with a 100 per cent success rate.
- The Trust replaced 96 per cent of its annual production through a combination of its \$364.5 million 2006 capital development program and by making oil and natural gas property acquisitions. The Trust added 16.3 mmboe of reserves from its 2006 capital development program and an additional 5.8 mmboe of reserves were added through \$132 million of net acquisitions. Fourth quarter capital spending increased to \$121.9 million compared to \$87.8 million in the same period of 2005.
- At year end 2006 the Trust's proved plus probable reserves stood at 286.1 mmboe, compared to 287 at year end 2005. The Trust's reserve life index is 12.4 years and reserves per unit remained constant relative to 2005 at 1.4 boe per unit.
- Oil prices were at historically high levels throughout much of the year while natural gas prices weakened significantly early in 2006. The price of oil reached a high of US\$77.03 per barrel in July before tumbling to a low of US\$55.81 per barrel in November. The AECO natural gas monthly index opened the year at \$12.11 per mcf and declined to a low of \$4.45 per mcf in October. The Trust's product mix being almost equally weighted to oil and natural gas served to mitigate the impact of the significant decline in natural gas prices in 2006 relative to 2005 levels. In addition, the Trust realized a cash gain of \$29.3 million on its hedging program in 2006 entirely due to natural gas hedges. Fourth quarter realized prices decreased significantly from 2005 and in particular natural gas prices.
- The Trust realized an operating netback, before hedging, of \$34.68 per boe in 2006 (\$31.37 per boe in Q4 2006) compared to \$37.66 per boe in 2005 (\$45.84 per boe in Q4 2005). The lower netback per boe was primarily due to the significant reduction in natural gas prices in 2006 and increased operating costs. Operating costs increased to \$8.49 per boe in 2006 (\$9.13 per boe in Q4 2006) compared to \$6.93 per boe in 2005 (\$7.16 per boe in Q4 2005), due to the higher cost Redwater and NPCU properties and overall industry operating cost increases.

- The Trust achieved a recycle ratio of 1.6 in 2006, a significant accomplishment in light of unprecedented industry activity and continual cost increases throughout 2006. The lower recycle ratio is due to higher finding, development and acquisition costs which were partly due to a significant investment in undeveloped land with no associated reserves. Net undeveloped land increased to 529,000 acres at year-end 2006, an increase of 43,000 acres from 2005. The Trust's three year average recycle ratio was 2.1 demonstrating a successful long-term capital development program and high quality of the Trust's assets.
- The Trust continues to maintain low debt levels as indicated by a net debt to 2006 cash flow from operations of 1.0 and net debt to total capitalization as at December 31, 2006 of 14 per cent. In addition, the Trust maintains a reclamation fund balance to provide for future abandonment and reclamation of its wells and facilities. The fund balance was \$30.9 million at December 31, 2006 and represents one of the largest reclamation funds in the oil and gas sector.
- On October 31, 2006, the Federal Government announced tax proposals pertaining to taxation of distributions paid by publicly traded income trusts ("the proposed Trust taxation"). Currently, the Trust does not pay tax on distributions as tax is paid by the unitholders. The proposals would result in a two-tiered tax structure whereby distributions would be subject to a 31.5 per cent tax at the Trust level commencing in 2011 and then unitholders would be subject to tax on the distribution as if it were a taxable dividend paid by a taxable Canadian corporation. The Tax announcement had a significant impact on the Canadian equity markets with a significant devaluation of trust unit prices. Despite the devaluation of the trust unit price following the taxation announcement, the Trust's core business remains unchanged. The Trust is currently assessing the draft legislation and alternatives with respect to the future structure of the Trust.
- Subsequent to year-end, options on ARC Energy Trust units began trading on the Montreal Stock Exchange. The options will enable investors to buy and sell "calls" and "puts" on ARC's Trust units.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This management's discussion and analysis ("MD&A") is dated February 20, 2007 and should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2006 and the audited consolidated financial statements and MD&A for the year ended December 31, 2005 and MD&A for the quarters ended March 31, 2006, June 30, 2006 and September 30, 2006.

Non-GAAP Measures

Management uses cash flow, cash flow from operations and cash flow from operations per unit derived from cash flow from operating activities (before changes in non-cash working capital and expenditures on site reclamation and restoration) to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian generally accepted accounting principles, ("GAAP") and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP.

The following table reconciles the cash flow from operating activities to cash flow from operations which is used frequently in this MD&A:

(\$ millions)	2006	2005
Cash flow from operating activities	734.0	616.7
Changes in non-cash working capital	16.0	17.9
Expenditures on site reclamation and restoration	10.6	4.9
Cash flow from operations	760.6	639.5

Management uses certain key performance indicators ("KPI's") and industry benchmarks such as operating netbacks ("netbacks"), total capitalization, finding, development and acquisition costs, recycle ratio, reserve life index, reserves per unit and production per unit to analyze financial and operating performance. Management feels that these KPI's and benchmarks are a key measure of profitability and overall sustainability for the Trust. These KPI's and benchmarks as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities.

Fourth Quarter Financial and Operational Results

The Trust had an active fourth quarter with the closing of \$93 million of acquisitions and \$121.9 million spent on capital development activities which contributed to quarterly average production of 63,663 boe per day. The Trust had a payout ratio of 70 per cent and funded \$48.8 million of its fourth quarter capital development program with cash flow. The fourth quarter was an active one for the Trust with the drilling of 59 gross wells on operated properties and new production coming on-stream.

Late in the fourth quarter, natural gas prices started to recover to levels not seen since the first quarter of 2006, however, oil prices declined. Due to increasing electricity prices, the Trust's fourth quarter operating costs were higher than previous quarters of 2006. Electricity prices declined to be in line with historical levels late in the quarter.

The Government's proposed Trust taxation announcement on October 31, 2006 was an unforeseen event in the fourth quarter of 2006 and it had a significant impact throughout the trust sector. With the government announcement, there was a significant devaluation in trust unit prices and a mass "sell off" of trust units whereby the Trust incurred an approximate 20 per cent decrease in the trust unit price and a resulting negative total return to unitholders in the fourth quarter and 2006 as a whole. Despite this event, ARC's core business is unchanged and the Trust's financial results are strong as indicated by record levels of production, revenue, capital spending, net income, cash flow, and distributions to unitholders in 2006.

Refer to "Quarterly Historical Review" in this MD&A for key quarterly financial and operational results.

- The Trust's fourth quarter production was 63,663 boe per day, an increase of eight per cent from the fourth quarter of 2005 due to acquisitions in late 2005 and during 2006.
- Cash flow decreased to \$174.4 million (\$0.85 per unit) from \$207.6 million (\$1.07 per unit) in the fourth quarter of 2005. Despite eight per cent higher volumes in the fourth quarter of 2006, significantly lower commodity prices and higher operating costs were the key contributors to the lower cash flow. Fourth quarter cash hedging gains of \$9.8 million partially offset the lower commodity prices (cash hedging losses were \$26.5 million in the fourth quarter of 2005).
- Net income decreased to \$56.6 million (\$0.28 per unit) from \$130.4 million (\$0.68 per unit) in the fourth quarter of 2005. In addition to the cash flow items listed above, 2006 net income decreased due to a \$19.8 million increase in foreign exchange losses, a \$22.5 million increase in depletion, a \$24.2 million decrease in non-cash gains on commodity and foreign currency contracts offset by a \$16.1 million decrease in future income tax expense and an \$8.3 million decrease in the non-cash portion of G&A as compared to 2005.
- The Trust maintained fourth quarter distributions at \$0.20 per unit per month and paid out \$122.3 million for a payout ratio of 70 per cent (56 per cent in the fourth quarter of 2005). The remaining \$52.1 million of fourth quarter cash flow was used to fund \$48.8 million (40 per cent) of the capital expenditure program and contribute \$3.4 million to the Trust's reclamation funds, including interest.
- Both oil and natural gas prices recovered slightly late in the fourth quarter, however the total realized price for the quarter was 26 per cent lower than in 2005 due primarily to significantly lower natural gas prices and a stronger Canadian dollar which resulted in lower Canadian denominated commodity prices. The WTI oil price averaged US\$60.22 per barrel in the fourth quarter, effectively unchanged from US\$60.05 barrel in 2005. The stronger Canadian dollar resulted in a lower Canadian denominated oil price of \$68.60 per barrel relative to \$70.45 per barrel in 2005. The AECO monthly natural gas price was \$6.36 per mcf, a 46 per cent decrease compared to the fourth quarter of 2005. The total realized price was \$49.94 per boe, a 26 per cent decrease compared to \$67.16 per boe in the fourth quarter of 2005.
- The fourth quarter netback before hedging decreased to \$31.37 per boe compared to \$45.84 per boe in 2005 due to a 26 per cent decrease in the realized price per boe. In addition, operating costs increased to \$9.13 per boe in 2006 due to the higher cost Redwater and NPCU properties acquired in late 2005. Alberta electricity prices were significantly higher in the fourth quarter of 2006 relative to 2005 and service and labour costs increased throughout the industry in 2006 relative to 2005 levels.
- The Trust spent \$121.9 million on capital development activities and undeveloped land in the fourth quarter compared to \$87.8 million in 2005. The Trust had a very active fourth quarter with the drilling of 59 gross wells (45 net wells) on operated properties with a 100 per cent success rate. The Trust expanded its inventory of undeveloped land acreage with the purchase of \$11.9 million of land in the fourth quarter. The land acquired was in core areas where the Trust has identified strategic development opportunities.

- Net debt levels increased to \$739.1 million in the fourth quarter as a result of \$93 million of acquisitions and debt funded capital expenditures of \$44.4 million. A devaluation of the Canadian dollar relative to the U.S. dollar also impacted the Trust's net debt levels as 71 percent of the Trust's debt is denominated in U.S. dollars. With the higher debt levels, interest expense increased to \$8.7 million (\$1.48 per boe) in the fourth quarter compared to \$6 million (\$1.11 per boe) in 2005.
- Cash G&A expenses increased to \$1.74 per boe from \$1.39 per boe in the fourth quarter of 2005. The increased G&A expenses were due to higher compensation costs in 2006. In addition, the Trust made a \$0.7 million cash payout under the Whole Unit Plan for units vesting in the fourth quarter while no units vested in the fourth quarter of 2005. Non-cash G&A per boe decreased significantly in the fourth quarter of 2006, with a recovery of \$0.02 per boe compared to an expense of \$1.43 per boe in 2005 due to the devaluation of the trust unit price following the proposed Trust taxation announcement on October 31, 2006, which resulted in a lower value of the Whole Unit Plan and resultant non-cash expense. In addition, the Trust recorded lower non-cash rights expense in the fourth quarter of 2006 due to majority of the rights having vested and thus been fully expensed early in 2006.

Fourth Quarter Financial and Operational Highlights			
(CDN\$ millions except per unit and per cent)	Q4 2006	Q4 2005	% Change
Production (boe/d)	63,663	59,120	8
Cash flow from operations	174.4	207.6	(16)
Per unit	\$ 0.85	\$ 1.07	(21)
Cash distributions	122.3	115.7	6
Per unit	\$ 0.60	\$ 0.60	-
Payout ratio (per cent)	70	56	26
Net income	56.6	130.4	(57)
Per unit	\$ 0.28	\$ 0.68	(59)
Prices			
WTI (US\$/bbl)	60.22	60.05	-
USD/CAD exchange rate	0.87	0.85	3
Realized oil price (CDN \$/bbl)	58.26	62.12	(6)
AECO gas monthly index (CDN \$/mcf)	6.36	11.68	(46)
Realized gas price (CDN \$/mcf)	6.99	12.05	(42)
Operating netback (\$/boe)			
Revenue, before hedging	49.94	67.16	(26)
Royalties	(8.80)	(13.51)	(35)
Transportation	(0.64)	(0.65)	(1)
Operating costs	(9.13)	(7.16)	28
Netback (before hedging)	31.37	45.84	(32)
Cash hedging gain (loss)	1.68	(4.86)	(135)
Netback (after hedging)	\$ 33.05	\$ 40.98	(20)
Capital expenditures	121.9	87.8	39
Capital funded with cash flow (per cent)	40	106	

2006 Annual Financial and Operational Results

Following is a discussion of ARC's 2006 annual financial and operating results.

Financial Highlights

(CDN \$ millions, except per unit and volume data)	2006	2005	% Change
Cash flow from operations	760.6	639.5	19
Cash flow from operations per unit ⁽¹⁾	3.72	3.35	11
Net income before future income tax and non-controlling interest	379.6	364.1	4
Net income	460.1	356.9	29
Net income per unit ⁽²⁾	2.28	1.90	20
Distributions per unit ⁽³⁾	2.40	1.99	21
Payout ratio per cent ⁽⁴⁾	64	59	8
Average daily production (boe/d) ⁽⁵⁾	63,056	56,254	12

⁽¹⁾ Per unit amounts are based on weighted average units plus units issuable for exchangeable shares at year-end.

- (2) Based on net income after non-controlling interest divided by weighted average trust units excluding trust units issuable for exchangeable shares.
- (3) Based on number of trust units outstanding at each cash distribution date.
- (4) Based on cash distributions divided by cash flow from operations.
- (5) Reported production amount is based on company interest before royalty burdens. Where applicable in this MD&A natural gas has been converted to barrels of oil equivalent (“boe”) based on 6 mcf:1 bbl. The boe rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the well head. Use of boe in isolation may be misleading.

Net Income

Net income in 2006 was \$460.1 million (\$2.28 per unit), an increase of \$103 million from \$356.9 million (\$1.90 per unit) in 2005 as a result of higher production volumes, strong oil prices throughout 2006 and total hedging gains on the commodity hedging program of \$24.7 million compared to losses of \$87.6 million in 2005. A significant future income tax recovery of \$87.1 million in 2006, attributed to the reduction in legislated future corporate income tax rates, also resulted in higher net income in 2006 relative to 2005.

Cash Flow from Operations

Cash flow from operations increased by 19 per cent in 2006 to \$761 million from \$640 million in 2005. The increase in 2006 cash flow was the result of a 12 per cent increase in production volumes, partially offset by lower natural gas prices. Cash flow was further increased by cash hedging gains of \$29.3 million in 2006 compared to a cash hedging loss of \$87.6 million in 2005. A change in the Trust’s product mix and the acquisition of properties with lower effective royalty rates resulted in lower royalty expense in 2006. The increases in 2006 cash flow were somewhat offset by higher operating costs, higher cash G&A expenses and higher interest expense attributed to increased debt levels. Per unit cash flow from operations increased 11 per cent to \$3.72 per unit from \$3.35 per unit in 2005.

Following is a summary of variances in cash flow from operations from 2005 to 2006:

	(\$ millions)	(\$ per trust unit)	(% variance)
2005 Cash flow from Operations	639.5	3.35	
Volume variance	\$ 140.9	\$ 0.74	% 22
Price variance	(75.6)	(0.40)	(12)
Cash gains on commodity and foreign currency contracts ⁽¹⁾	116.8	0.61	18
Royalties	13.0	0.07	2
Expenses:			
Transportation	(0.2)	(0.00)	-
Operating ⁽²⁾	(54.0)	(0.28)	(8)
Cash G&A	(8.9)	(0.05)	(1)
Interest	(14.8)	(0.08)	(2)
Taxes	3.6	0.02	1
Realized foreign exchange gain	0.3	0.00	-
Weighted average trust units		(0.26)	
2006 Cash flow from Operations	\$ 760.6	\$ 3.72	% 19

(1) Represents cash losses on commodity and foreign currency contracts including cash settlements on termination of commodity and foreign currency contracts.

(2) Excludes non-cash portion of LTIP expense recorded in operating costs.

Production

Production volume averaged 63,056 boe per day in 2006 compared to 56,254 boe per day in 2005. The Redwater and North Pembina Cardium Unit (“NPCU”) acquisitions contributed approximately 5,500 boe per day (net) in 2006 that includes 580 boe per day (net) of incremental production on wells reactivated during the year. With the acquisition of producing properties in Manitoba, an incremental 785 boe per day of production came on-stream in the fourth quarter of 2006.

The Trust’s objective is to maintain annual production through the drilling of wells and other development activities. In fulfilling this objective, there may be fluctuations in production depending on the timing of new wells coming on-stream. During 2006, the Trust drilled 294 gross wells (219 net wells) on operated properties; 72 gross oil wells and 222 gross natural gas wells with a 99 per cent success rate.

The Trust expects that 2007 full year production will be approximately 63,000 boe per day and that 275 gross wells (225 net wells) will be drilled by ARC on operated properties with participation in an additional 150 gross wells to be drilled on the Trust’s non-operated properties. The Trust estimates that the 2007 drilling program will add 11,000 boe per day of production which will offset production declines at existing properties.

Production	2006	2005	% Change
Crude oil (bbl/d)	27,674	22,032	26
Heavy oil (bbl/d)	1,368	1,250	9
Natural gas (mcf/d)	179,067	173,800	3
NGL (bbl/d)	4,170	4,005	4
Total production (boe/d) ⁽¹⁾	63,056	56,254	12
% Natural gas production	47	51	
% Crude oil and liquids production	53	49	

⁽¹⁾ Reported production for a period may include minor adjustments from previous production periods.

Oil production increased by 25 per cent to 29,042 boe per day in 2006 from 23,282 boe per day in 2005. The increase in oil production was largely attributed to the Redwater and NPCU acquisitions late in 2005. The Trust's weighting of oil and liquids production increased to 53 per cent in 2006 from 49 per cent in 2005 as the new volumes from Redwater and NPCU were primarily liquids.

Natural gas production increased to 179.1 mmcf per day in 2006, a three per cent increase from the 173.8 mmcf per day produced in 2005. The majority of this increase was as a result of ARC's active 2006 internal drilling program particularly in northern and central Alberta. In addition, the Trust drilled 125 net operated natural gas wells in southeastern Alberta and southwestern Saskatchewan during 2006, the majority of which were drilled in the third quarter and came on production during the fourth quarter.

The following table summarizes the Trust's production by core area:

Production Core Area ⁽¹⁾	2006				2005			
	Total (boe/d)	Oil (bbl/d)	Gas (mmcf/d)	NGL (bbl/d)	Total (boe/d)	Oil (bbl/d)	Gas (mmcf/d)	NGL (bbl/d)
Central AB	8,206	1,553	31.3	1,433	8,041	1,364	30.2	1,641
Northern AB & BC	18,897	6,194	67.6	1,452	18,286	6,026	65.3	1,381
Pembina & Redwater	13,950	9,453	20.0	1,157	7,953	4,166	17.7	832
S.E. AB & S.W. Sask.	10,743	1,071	58.0	9	11,298	1,499	58.7	15
S.E. Sask.	11,260	10,771	2.2	119	10,676	10,227	1.9	136
Total	63,056	29,042	179.1	4,170	56,254	23,282	173.8	4,005

⁽¹⁾ Provincial references: AB is Alberta, BC is British Columbia, Sask. is Saskatchewan, S.E. is southeast, S.W. is southwest.

Commodity Prices Prior to Hedging

Average Benchmark Prices	2006	2005	% Change
AECO gas (\$/mcf) ⁽¹⁾	6.98	8.45	(17)
WTI oil (US\$/bbl) ⁽²⁾	66.25	56.61	17
USD/CAD foreign exchange rate	0.88	0.83	6
WTI oil (CDN \$/bbl)	75.00	68.52	9

⁽¹⁾ Represents the AECO monthly posting.

⁽²⁾ WTI represents West Texas Intermediate posting as denominated in US\$.

Oil prices reached historic highs in 2006 peaking at US\$77.03 per barrel averaging US\$66.25 per barrel for the full year of 2006. The strength of the Canadian dollar served to partially offset the impact of higher U.S. denominated oil prices. The Trust's oil production consists predominantly of light and medium crude oil while heavy oil accounts for less than three per cent of the Trust's liquids production. Overall the price of WTI oil in Canadian dollars increased by nine per cent over the prior year to \$75.00 versus \$68.52 in 2005.

Alberta AECO Hub natural gas prices, which are commonly used as an industry reference, averaged \$6.98 per mcf in 2006 compared to \$8.45 per mcf in 2005. Natural gas prices started the year at an historic high point of \$12.11 per mcf but declined dramatically throughout the second and third quarters. ARC's realized gas price, before hedging, decreased by 22 per cent to \$6.97 per mcf compared to \$8.96 per mcf in 2005. ARC's realized gas price is based on prices received at the various markets in which the Trust sells its natural gas. ARC's natural gas sales portfolio consists of gas sales priced at the AECO monthly index, the AECO daily spot market, eastern and mid-west United States markets and a portion to aggregators.

Prior to hedging activities, ARC's total realized commodity price was \$53.33 per boe in 2006, a six per cent decrease from the \$56.54 per boe received prior to hedging in 2005.

The following is a summary of realized prices:

ARC Realized Prices Prior to Hedging	2006	2005	% Change
Oil (\$/bbl)	65.26	61.11	7
Natural gas (\$/mcf)	6.97	8.96	(22)
NGL (\$/bbl)	52.63	49.92	5
Total commodity revenue before hedging (\$/boe)	53.33	56.54	(6)
Other revenue (\$/boe)	0.13	0.21	(38)
Total revenue before hedging (\$/boe)	53.46	56.75	(6)

Revenue

Revenue increased to a historical high of \$1.2 billion in 2006. The increase in revenue was attributable to higher volumes and higher oil prices which were partially offset by lower natural gas prices.

A breakdown of revenue is as follows:

Revenue (\$ millions)	2006	2005	% Change
Oil revenue	691.8	519.3	33
Natural gas revenue	455.7	568.7	(20)
NGL revenue	80.1	73.0	10
Total commodity revenue	1,227.6	1,161.0	6
Other revenue	2.9	4.2	(31)
Total revenue	1,230.5	1,165.2	6

Risk Management and Hedging Activities

The Trust continues to maintain a strong hedging mandate with an emphasis on protecting cash flow and distributions to unitholders.

The Trust's risk management activities are conducted by an internal Risk Management Committee, based upon guidelines approved by the Board and the following mandate:

- protect unitholder return on investment;
- provide protection for minimum monthly cash distributions to unitholders;
- employ a portfolio approach to risk management by entering into a number of small positions that build upon each other;
- participate in commodity price upturns to the greatest extent possible while limiting exposure to price downturns; and,
- ensure profitability of specific oil and gas properties that are more sensitive to changes in market conditions.

To satisfy this mandate, the board of directors has approved that up to three per cent of forecast revenues may be spent on option premiums on a go-forward basis to achieve price protection and satisfy the risk management mandate while limiting the risk exposure of hedged positions.

In 2006 ARC implemented the following strategies to protect distributions and provide upside commodity price participation to the unitholder:

- Protected power consumption with electricity swaps;
- Protected natural gas prices with an energy equivalent swap to crude oil;
- Protected the 2005 Redwater acquisitions volume with US\$55 floors via a 3-way collar;
- Protected price conversion of US\$ denominated WTI crude oil with foreign exchange swaps;
- Protected on average 44 per cent of natural gas production and 35 per cent of crude oil production for the year;
- Protected as much as 62 per cent of natural gas production volumes during the most vulnerable fall months;
- Protected natural gas and crude oil production with a portfolio of floor and ceiling option contracts.

ARC uses a combination of puts and call options otherwise known as floors and ceilings to protect budgeted commodity prices. A floor or put option ensures a minimum selling price and a ceiling or call option establishes a

maximum selling price. ARC employs a strategy of buying floors and offsetting the cost of those floors by selling ceilings at higher prices or selling additional floors at lower prices. The net cost or premiums associated with the protection that is put in place is viewed as an insurance premium to ensure cash flow and stability of distributions, while maintaining strong upside price participation.

By implementing these strategies ARC realized total cash hedging gains of \$29.3 million in 2006 as illustrated in detail in the “Gain or Loss on Commodity and Foreign Currency Contracts” section of this MD&A. In addition, cash hedging gains of \$3.4 million on electricity hedges have been recorded as a reduction of 2006 operating costs.

On a forward-looking basis ARC continues to put layers of protection in place on both crude oil and natural gas. ARC has protection on approximately 40 per cent of oil production and 25 per cent of natural gas production for 2007 as shown in the following table which represents ARC’s positions in place as at January 31, 2007.

2007 Hedge Positions as at January 31, 2007 ⁽¹⁾⁽²⁾									
Q1			Q2		Q3		Q4		
Crude Oil	US\$/bbl	bbl/day	US\$/bbl	bbl/day	US\$/bbl	bbl/day	US\$/bbl	bbl/day	
Sold Call	89.05	7,500	89.05	7,500	87.65	7,500	87.65	7,500	
Bought Put	63.42	13,656	63.46	13,000	61.67	12,000	61.67	12,000	
Sold Put	50.02	10,000	50.02	13,000	48.13	12,000	48.13	12,000	
Natural Gas	CDN\$/GJ	GJ/day	CDN\$/GJ	GJ/day	CDN\$/GJ	GJ/day	CDN\$/GJ	GJ/day	
Sold Call	10.89	93,566	8.39	113,028	8.89	50,000	10.58	30,839	
Bought Put	7.97	93,566	7.05	113,028	7.15	50,000	7.62	30,839	
Sold Put	5.50	10,000	5.15	50,000	5.15	50,000	5.15	16,848	
FX	CAD/USD	\$M/month	CAD/USD	\$M/month	CAD/USD	\$M/month	CAD/USD	\$M/month	
Bought Put	1.1321	2.4	1.1321	2.4	1.1321	2.4	1.1321	2.4	
Sold Put	1.0990	2.0	1.0990	2.0	1.0990	2.0	1.0990	2.0	
Swap	1.1387	16.6	1.1387	16.6	1.1387	16.6	1.1387	16.6	

(1) Note that the prices and volumes noted above represents averages for several contracts and the average price for the portfolio of options listed above does not have the same payoff profile as the individual option contracts. Viewing the average price of a group of options is purely for indicative purposes. The natural gas price shown translates all NYMEX positions to an AECO equivalent price. In addition to positions shown here, ARC has entered into additional basis positions.

(2) Please refer to the Trust’s website at www.arcenergytrust.com under “Hedging Program” within the “Investor Relations” section for details on the Trust’s hedging positions as of January 31, 2007.

The above table should be interpreted as follows using the 2007 Q1 Crude Oil Hedges as an example. For oil, the Trust has hedged 13,656 barrels per day at a minimum average price of US\$63.42 and participates in prices up to a maximum average of US\$89.05 on 7,500 barrels per day with no limit on the remaining 6,156 barrels per day hedged. Finally, ARC’s average protected price of \$63.42 reduces penny for penny at an average price below \$50.02 on 10,000 barrels per day.

During 2006 ARC entered into “basis” natural gas contracts to lock in the difference between the Henry Hub index and the AECO monthly index. This set of transactions diversifies ARC’s price exposure from the AECO basin to the broader North American market, thus reducing ARC’s sensitivity to regional market events. Basis swaps are negotiated in terms of a fixed price in US\$ per mmbtu that is deducted from the NYMEX natural gas price. For the period January 1, 2007 through March 2007, the Trust locked in the basis at US\$1.31 per mmbtu on an average volume of 40,000 mcf per day and ARC has an average basis price of US\$1.08 per mmbtu on an average volume of 50 mcf per day of natural gas for the period of April 2007 through October 2010.

In addition to these positions the Trust has fixed the price of electricity for a portion of its power consumption at average prices between \$59.33 and \$64.63 through 2010 to mitigate the risk associated with fluctuating electricity prices which have a large impact on operating costs. A significant portion of the Trust’s power usage is subject to the deregulated Alberta Power Pool price which was extremely volatile during 2006 and ranged from a record high monthly average price of \$174.09 mw/h to a low of \$42.87 mw/h. The electricity hedge represents approximately 69 per cent of the Trust’s Alberta power consumption at operated properties.

The Trust considers its risk management contracts to be effective economic hedges as they meet the objectives of the Trust’s risk management mandate. In order to mitigate credit risk, the Trust executes commodity and foreign currency hedging risk management with financially sound, credit worthy counterparties. All contracts require approval of the Trust’s Risk Management Committee prior to execution. Deferred premiums payable will be recorded as a

realized cash hedging loss when payment is made in a future period. These premiums may be partially offset if ARC sells any short-term options. The Trust's oil contracts are based on the WTI index and the majority of the Trust's natural gas contracts are based on the AECO monthly index.

For a complete summary of the Trust's oil, natural gas and foreign exchange hedges, please refer to "Hedging Program" under the "Investor Relations" section of the Trust's website at www.arcenergytrust.com.

Gain or Loss on Commodity and Foreign Currency Contracts

Gain or loss on commodity and foreign currency contracts comprise realized and unrealized gains or losses on commodity and foreign currency contracts that do not meet the accounting definition of the requirements of an effective hedge, even though the Trust considers all commodity and foreign currency contracts to be effective economic hedges. Accordingly, gains and losses on such contracts are shown as a separate category in the statement of income.

The Trust recorded a realized cash gain on commodity and foreign currency contracts of \$29.3 million in 2006 as compared to a loss of \$87.6 million recorded in 2005. The majority of the 2006 cash gains were attributed to the natural gas hedges whereby the Trust utilized a variety of contracts to lock in the minimum price on natural gas. As gas prices declined subsequent to the first quarter, the Trust realized significant gains on the contracts.

The following is a summary of the total gain (loss) on commodity and foreign currency contracts for 2006:

Commodity and foreign currency contracts (\$ millions)	Crude Oil & Liquids	Natural Gas	Foreign Currency	2006 Total	2005 Total
Realized cash gain (loss) on contracts ⁽¹⁾	(7.7)	29.7	7.3	29.3	(87.6)
Unrealized gain (loss) on contracts ⁽²⁾	6.2	(4.1)	(6.7)	(4.6)	-
Total gain (loss) on commodity and foreign currency contracts	(1.5)	25.6	0.6	24.7	(87.6)

⁽¹⁾ Realized cash gains and losses represent actual cash settlements or receipts under the respective contracts.

⁽²⁾ The unrealized (loss) gain on contracts represents the change in fair value of the contracts during the period.

Operating Netbacks

The Trust's operating netback, after realized hedging gains or losses, increased eight per cent to \$35.95 per boe in 2006 compared to \$33.40 per boe in 2005. The increase in netbacks in 2006 is primarily due to higher oil prices in 2006, a decrease in royalties, and cash hedging gains of \$1.27 per boe compared to losses of \$4.26 per boe in 2005. A decline in natural gas prices and higher operating costs partially offset the higher revenue and lower royalties.

The components of operating netbacks are shown below:

Netbacks (\$ per boe)	Crude Oil (\$/bbl)	Heavy Oil (\$/bbl)	Gas (\$/mcf)	NGL (\$/bbl)	2006 Total (\$/boe)	2005 Total (\$/boe)
Weighted average sales price	66.16	46.90	6.97	52.63	53.33	56.54
Other revenue	-	-	-	-	0.13	0.21
Total revenue	66.16	46.90	6.97	52.63	53.46	56.75
Royalties	(10.80)	(4.86)	(1.37)	(14.08)	(9.66)	(11.46)
Transportation	(0.14)	(0.86)	(0.19)	-	(0.63)	(0.70)
Operating costs ⁽¹⁾	(11.51)	(10.63)	(0.96)	(7.49)	(8.49)	(6.93)
Netback prior to hedging	43.71	30.55	4.45	31.06	34.68	37.66
Realized gain (loss) on commodity and foreign currency contracts	(0.05)	-	0.45	-	1.27	(4.26)
Netback after hedging	43.66	30.55	4.90	31.06	35.95	33.40

⁽¹⁾ Operating expenses are composed of direct costs incurred to operate oil and gas wells. A number of assumptions have been made in allocating these costs between oil, heavy oil, natural gas and natural gas liquids production.

Royalties decreased to \$9.66 per boe in 2006 compared to \$11.46 per boe in 2005. Royalties as a percentage of pre-hedged commodity revenue net of transportation costs decreased to 18 per cent compared to 20 per cent in 2005. The decrease in royalties is due to a lower effective royalty rate in 2006 as a result of the increased oil weighting of the Trust's production following the 2005 acquisitions and royalty concessions received on certain British Columbia

natural gas properties. In addition, the Redwater and NPCU properties acquired in 2005 carried a significantly lower effective royalty rate than the Trust's existing properties due to the royalty structure of the properties.

Operating costs increased to \$8.49 per boe compared to \$6.93 per boe in 2005. The acquisition of the Redwater and NPCU properties, with operating costs of approximately \$22 per boe in 2006, contributed to a large portion of the 23 per cent increase in operating costs. However, the Redwater and NPCU properties also contribute high netbacks of \$40.60 per boe and \$40.19 per boe, respectively, due to the premium oil quality and low royalty regime. Despite reductions in natural gas prices during 2006, the industry was still experiencing increasing costs for services, supplies, materials, electricity and labour throughout 2006. In particular, areas in northern Alberta experienced significant cost increases for services, materials and labour. In addition, the cost of electricity in Alberta was extremely volatile during the second half of 2006 with daily average prices ranging from \$16.49 mw/h to \$576.10 mw/h. Approximately 69 per cent of the Trust's electricity usage on Alberta operated properties was hedged at approximately \$63 mw/h whereby the Trust was partially protected from the increases in electricity costs. The electricity hedge resulted in a \$0.15 per boe reduction in operating costs in 2006.

Transportation costs decreased 10 per cent to \$0.63 per boe in 2006 compared to \$0.70 per boe in 2005. This is a result of the increased percentage of oil in the Trust's production mix as oil generally has a lower transportation cost than natural gas as a majority of the Trust's oil production is sold at the plantgate.

In 2007 it is expected that operating costs will increase by approximately five per cent to \$8.95 per boe primarily due to costs associated with our newly acquired properties and the additional 11,000 boe per day of 2007 development production volumes. The Trust expects that the industry cost pressures will ease slightly in 2007 due to the moderation in industry activity levels experienced late in 2006.

General and Administrative Expenses and Trust Unit Incentive Compensation

Cash G&A net of overhead recoveries on operated properties increased 32 per cent to \$36.3 million in 2006 from \$27.4 million in 2005. Increases in cash G&A expenses for 2006 were due to increased staff levels, higher compensation costs and the nature of ARC's long-term incentive program. As a result of the unprecedented levels of activity for ARC and for the industry as a whole, the costs associated with hiring, compensating and retaining employees and consultants have risen. The increase in G&A costs was partially offset by higher overhead recoveries attributed to high levels of capital and operating activity throughout 2006 and as a result of incremental overhead charged on new and existing operated properties. On a per boe basis, cash G&A costs increased 18 per cent to \$1.58 per boe from \$1.34 per boe as a result of higher cash G&A costs partially offset by increased production volume.

The Trust paid out \$5.2 million under the whole unit plan in 2006 compared to \$1.6 million in 2005 (\$3.5 million and \$1.1 million of the payouts were allocated to G&A in 2006 and 2005, respectively, and the remainder to operating costs and capital projects). The higher cash payment in 2006 is attributed to a higher unit price upon vesting in April and October of each year, higher distributions and having two years of awards vesting in 2006 compared to one year of awards in 2005. The next cash payment under the Whole Unit Plan is scheduled to occur in April 2007.

The following is a breakdown of G&A and trust unit incentive compensation expense:

G&A and Trust Unit Incentive Compensation Expense (\$ millions except per boe)	2006	2005	% Change
G&A expenses	45.8	35.0	31
Operating recoveries	(12.9)	(8.7)	48
Cash G&A expenses before Whole Unit Plan	32.9	26.3	25
Cash Expense – Whole Unit Plan	3.5	1.1	218
Cash G&A expenses including Whole Unit Plan	36.4	27.4	32
Accrued compensation - Rights Plan	2.5	6.5	(62)
Accrued compensation - Whole Unit Plan	8.2	8.8	(7)
Total G&A and trust unit incentive compensation expense	47.1	42.7	10
Cash G&A expenses per boe	1.58	1.34	18
Total G&A and trust unit incentive compensation expense per boe	2.05	2.08	(1)

A non-cash trust unit incentive compensation expense ("non-cash compensation expense") of \$10.7 million (\$0.47 per boe) was recorded in 2006 compared to \$15.3 million (\$0.74 per boe) in 2005. This non-cash amount relates to estimated costs of the Trust Unit Incentive Rights Plan ("Rights Plan") and the Whole Trust Unit Incentive Plan ("Whole Unit Plan") to December 31, 2006. Despite a higher number of units outstanding under the plan in 2006, there was a decrease in the value of the Whole Unit Plan and a reduction in the non-cash expense due to the decline in trust unit prices following the Federal Government's proposed Trust taxation announcement in the fourth quarter of

2006.

Rights Plan

The Rights Plan provides employees, officers and independent directors the right to purchase units at a specified price. The rights have a five year term and vest equally over three years. The exercise price of the rights is adjusted downwards from time to time by the amount that distributions to unitholders, in any calendar quarter exceeds 2.5 per cent of the Trust's net book value of property, plant and equipment. The rights plan was replaced by a Whole Unit Plan during 2004 after which no further rights under the rights plan were issued. During 2006, one million rights were exercised or cancelled and 0.4 million rights remained outstanding as at December 31, 2006. Of the remaining rights outstanding, 6,000 will vest in March 2007 and compensation expense will be recorded until that time. All other rights were fully vested and expensed as of December 31, 2006.

The decrease in compensation expense for the rights plan in 2006 is due to the majority of rights having vested early in 2006 and compensation expense is only recorded up to vesting date.

Whole Trust Unit Incentive Plan ("Whole Unit Plan")

In March 2004, the Board of Directors approved a new Whole Unit Plan to replace the Rights Plan for new awards granted subsequent to the first quarter of 2004. The new Whole Unit Plan results in employees, officers and directors (the "plan participants") receiving cash compensation in relation to the value of a specified number of underlying units. The Whole Unit Plan consists of Restricted Trust Units ("RTUs") for which the number of units is fixed and will vest over a period of three years and Performance Trust Units ("PTUs") for which the number of units is variable and will vest at the end of three years.

Upon vesting, the plan participant is entitled to receive a cash payment based on the fair value of the underlying trust units plus accrued distributions. The cash compensation issued upon vesting of the PTUs is dependent upon the performance of the Trust compared to its peers and indicated by the performance multiplier. The performance multiplier is based on the percentile rank of the Trust's total unitholder return compared to its peers. Total return is calculated as the sum of the change in the market price of the units in the period plus the amount of distributions in the period. The performance multiplier ranges from zero, if ARC's performance ranks in the bottom quartile, to two for top quartile performance.

The following table shows the changes during the year of RTUs and PTUs outstanding:

Whole Unit Plan (units in thousands and \$ millions except per unit)	Number of RTUs	Number of PTUs	Total RTUs and PTUs
Balance, beginning of period	479	391	870
Granted in the period	373	303	676
Vested in the period	(180)	-	(180)
Forfeited in the period	(24)	(11)	(35)
Balance, end of period ⁽¹⁾	648	683	1,331
Estimated distributions to vesting date ⁽²⁾	168	222	390
Estimated units upon vesting after distributions	816	905	1,721
Performance multiplier ⁽³⁾	-	2.0	
Estimated total units upon vesting	816	1,810	2,626
Trust unit price at December 31, 2006	\$22.30	\$22.30	\$22.30
Estimated total value upon vesting	\$18.2	\$40.4	\$58.6

(1) Based on underlying units before performance multiplier and accrued distributions.

(2) Represents estimated additional units to be issued equivalent to estimated distributions accruing to vesting date.

(3) The performance multiplier only applies to PTUs and approximated 2.0 at December 31, 2006. The performance multiplier is assessed each period end based on actual results of the Trust relative to its peers.

The value associated with the RTUs and PTUs is expensed in the statement of income over the vesting period with the expense amount being determined by the unit price, the number of PTUs to be issued on vesting, and distributions. Therefore, the expense recorded in the statement of income fluctuates over time.

As at December 31, 2006, the PTUs outstanding were assessed to have a percentile rank equal or greater than 75 and thus were valued with a performance multiplier of 2.0. Below is a summary of the range of future expected payments under the Whole Unit Plan based on variability of the performance multiplier:

Value of Whole Unit Plan as at December 31, 2006	Performance multiplier
---	------------------------

(units thousands and \$ millions except per unit)	-	1.0	2.0
Estimated trust units to vest			
RTUs	816	816	816
PTUs	-	905	1,810
Total units ⁽¹⁾	816	1,721	2,626
Trust unit price ⁽²⁾	22.30	22.30	22.30
Trust unit distributions per month ⁽²⁾	0.20	0.20	0.20
Value of Whole Unit Plan upon vesting	18.2	38.8	58.6
Officers	2.1	11.6	20.9
Directors	1.4	1.4	1.4
Staff	14.7	25.8	36.3
Total payments under Whole Unit Plan ⁽³⁾	18.2	38.8	58.6
2007	7.8	11.2	14.6
2008	6.7	14.9	23.1
2009	3.7	12.7	20.9

(1) Includes additional estimated units to be issued for accrued distributions to vesting date.

(2) Values will fluctuate over the vesting period based on the volatility of the underlying trust unit price and distribution levels. Assumed future trust unit price of \$22.30 per trust unit and distributions of \$0.20 per unit per month based on current levels.

(3) Upon vesting, a cash payment is made equivalent to the value of the underlying trust units. The payment is made on vesting dates in April and October of each year and at that time is reflected as a reduction of cash flow from operations.

Due to the variability in the future payments under the plan, the Trust estimates that \$18.2 million to \$58.6 million will be paid out from 2007 through 2009 based on the current trust unit price, distribution levels and a performance multiplier ranging from zero to two.

Interest Expense

Interest expense increased to \$31.8 million in 2006 from \$16.9 million in 2005 due to an increase in short-term interest rates, and higher debt balances as a result of the Trust's acquisitions activity which was funded \$125 million with debt. As at December 31, 2006, the Trust had \$687.1 million of debt outstanding, of which \$261 million was fixed at a weighted average rate of 5.056 per cent and \$426.1 million was floating at current market rates plus a credit spread of 65 basis points. Seventy-one percent of the Trust's debt is denominated in U.S. dollars.

The following is a summary of the debt balance and interest expense for 2006 and 2005:

Interest Expense (\$ millions)	2006	2005	% Change
Year end debt balance ⁽¹⁾	687.1	526.6	30
Fixed rate debt	261.0	268.2	(3)
Floating rate debt	426.1	258.4	65
Interest expense before interest rate swaps ⁽²⁾	31.4	17.4	80
Loss (gain) on interest rate hedge	0.4	(0.5)	180
Net interest expense	31.8	16.9	88

(1) Includes both long-term and current portions of debt.

(2) The interest rate swap was designated as an effective hedge for accounting purposes whereby actual realized gains and losses are netted against interest expense.

Foreign Exchange Gains and Losses

The Trust recorded a loss of \$4.2 million (\$0.18 per boe) on foreign exchange transactions compared to a gain of \$6.4 million (\$0.31 per boe) in 2005. These amounts include both realized and unrealized foreign exchange gains and losses. Unrealized foreign exchange gains and losses are due to revaluation of U.S. denominated debt balances. The volatility of the Canadian dollar during the reporting period has a direct impact on the unrealized component of the foreign exchange gain or loss. The unrealized gain/loss impacts net income but does not impact cash flow as it is a non-cash amount. Realized foreign exchange gains or losses arise from U.S. denominated transactions such as interest payments, debt repayments and hedging settlements.

Included in the 2006 realized foreign exchange gain was a gain of \$2.6 million realized upon repayment of US\$6 million of debt in 2006. The debt was issued in 2002 when the USD/CAD foreign exchange rate was approximately 0.64 and strengthened considerably to 0.88 on repayment in 2006. The 2006 unrealized foreign exchange loss of \$7.2 million was due to the revaluation of U.S. denominated debt balances associated with the weakening of the Canadian dollar relative to the U.S. dollar in 2006.

Taxes

In 2006, a future income tax recovery of \$87.1 million was included in income compared to a \$1.6 million expense in 2005. The significant increase in the future income tax recovery in 2006 was due to the legislated reduction in the future corporate income tax rates in the second quarter of 2006 whereby the Trust's expected future income tax rate decreased to 29.4 per cent from 33.7 per cent prior to the rate reductions.

Acquisitions completed in 2006 resulted in the Trust recording a future income tax liability of \$5.4 million due to the difference between the tax basis and the fair value assigned to the acquired assets. The amount of tax pools versus asset value is one of the parameters that impacts the Trust's acquisition bid levels.

At December 31, 2006 the Trust's subsidiaries had tax pools of approximately \$1 billion. The tax pools consist of \$903 million of tangible and intangible capital assets, \$18.2 million of non-capital loss carryforwards which expire at various periods to 2026, and \$110 million for other tax pools. In addition to the above tax basis for the Trust's subsidiaries, the Trust itself had an approximate tax basis of \$545.1 million as at December 31, 2006.

On October 31, 2006, the Federal Government announced the Trust taxation. Currently, distributions paid to unitholders, other than returns of capital, are claimed as a deduction by the Trust in arriving at taxable income whereby tax is eliminated at the Trust level and is paid by the unitholders. The proposals would result in a two-tiered tax structure whereby distributions would first be subject to a 31.5 per cent tax at the Trust level commencing in 2011, and then unitholders would be subject to tax on the distribution as if it were a taxable dividend paid by a taxable Canadian corporation. If enacted, the proposals would apply to the Trust effective January 1, 2011. The Trust is currently assessing various alternatives with respect to the potential implications of the tax proposals, however until the legislation is enacted in final form, the Trust will not arrive at a final conclusion with respect to future Trust structure and implications to the Trust. As the tax proposals had not yet been substantively enacted as of December 31, 2006, the consolidated financial statements do not reflect the impact of the proposed taxation.

The corporate income tax rate applicable to 2006 is 34.5 per cent, however ARC does not anticipate any material cash income taxes will be paid for fiscal 2006. Due to the Trust's structure, currently, both income tax and future tax liabilities are passed on to the unitholders by means of royalty payments made between ARC Resources and the Trust.

Capital taxes were eliminated effective January 1, 2006 pursuant to the Federal Government budget of May 2, 2006.

Depletion, Depreciation and Accretion of Asset Retirement Obligation

The depletion, depreciation and accretion ("DD&A") rate increased to \$15.64 per boe in 2006 from \$12.88 per boe in 2005. The higher DD&A rate is due to the Redwater and NPCU acquisitions in the fourth quarter of 2005 for which the Trust recorded a higher proportionate cost per barrel of proved reserves of the acquired operations compared to the existing ARC properties. In addition, the Trust completed net acquisitions in 2006 for \$131.8 million plus an additional \$5.4 future income tax liability recorded on acquisition, both acquisitions were at a higher proportionate cost per barrel of proved reserves than existing ARC properties. Accretion expense was also higher in 2006 as a result of the higher asset retirement obligation recorded late in 2005 primarily attributed to the acquired Redwater and NPCU properties.

A breakdown of the DD&A rate is as follows:

DD&A Rate (\$ millions except per boe amounts)	2006	2005	% Change
Depletion of oil & gas assets ⁽¹⁾	348.9	259.3	35
Accretion of asset retirement obligation ⁽²⁾	11.1	5.2	113
Total DD&A	360.0	264.5	36
DD&A rate per boe	15.64	12.88	21

⁽¹⁾ Includes depletion of the capitalized portion of the asset retirement obligation that was capitalized to the property, plant and equipment ("PP&E") balance and is being depleted over the life of the reserves.

⁽²⁾ Represents the accretion expense on the asset retirement obligation during the year.

The costs subject to depletion included \$61.3 million relating to the capitalized portion of the asset retirement obligation as at December 31, 2006 (\$61.9 million as at December 31, 2005), net of accumulated depletion.

Goodwill

The goodwill balance of \$157.6 million arose as a result of the acquisition of Star in 2003. The goodwill balance was determined based on the excess of total consideration paid plus the future income tax liability less the fair value of the assets for accounting purposes acquired in the transaction.

Accounting standards require that the goodwill balance be assessed for impairment at least annually or more frequently if events or changes in circumstances indicate that the balance might be impaired. If such an impairment exists, it would be charged to income in the period in which the impairment occurs. The Trust has determined that there was no goodwill impairment as of December 31, 2006.

Capital Expenditures and Net Acquisitions

Total capital expenditures, excluding acquisitions and dispositions, totaled \$364.5 million in 2006 compared to \$268.8 million in 2005. This amount was incurred on drilling and completions, geological, geophysical and facilities expenditures, and the purchase of undeveloped acreage. The significant increase in 2006 capital expenditures is reflective of the Trust's higher production, larger asset base and the higher cost to replace production as well as increased spending on undeveloped land.

In addition to capital expenditures on development activities, the Trust completed net property acquisitions of \$115.2 million in 2006. The most significant property acquisition was the purchase of Manitoba properties accounting for 785 boe per day of oil production and 3.4 mmoeb of proved plus probable reserves for cash consideration of \$74 million. The Trust also completed one minor corporate acquisition for consideration of \$16.6 million in 2006.

During the year, the Trust drilled 294 gross wells (219 net wells) on operated properties; consisting of 72 gross oil wells and 222 gross natural gas wells most of which were shallow gas wells with a success rate of 99 per cent. In addition, the Trust participated in 443 gross wells (40 net wells) drilled by other operators.

Proved plus probable oil and gas reserves were effectively maintained at 286.1 mmoeb at year end 2006 as a result of the Trust's 2006 capital expenditure program and property and corporate acquisitions.

A breakdown of capital expenditures and net acquisitions is shown below:

Capital Expenditures (\$ millions)	2006	2005	% Change
Geological and geophysical	11.4	9.2	24
Drilling and completions	240.5	191.8	25
Plant and facilities	77.6	55.0	41
Undeveloped land	32.4	9.1	256
Other capital	2.6	3.7	(30)
Total capital expenditures	364.5	268.8	36
Producing property acquisitions ⁽¹⁾	124.0	111.3	11
Producing property dispositions ⁽¹⁾	(8.8)	(20.0)	(57)
Corporate acquisitions ⁽²⁾	16.6	505.0	(967)
Total capital expenditures and net acquisitions	496.3	865.1	(426)

⁽¹⁾ Value is net of post-closing adjustments.

⁽²⁾ Represents total consideration for the transactions, including fees but is prior to the related future income tax liability, asset retirement obligation and working capital assumed on acquisition.

Approximately 72 per cent of the \$364.5 million capital program was financed with cash flow from operations in 2006 compared to 95 per cent in 2005. Property and corporate acquisitions were financed through a combination of debt and proceeds from the 2006 distribution reinvestment program and employee rights plan.

Source of Funding of Capital Expenditures and Net Acquisitions

(\$ millions)

	2006			2005		
	Development Capital	Net Acquisitions	Total Expenditures	Development Capital	Net Acquisitions	Total Expenditures
Expenditures	364.5	131.8	496.3	268.8	596.3	865.1
Per cent funded by:						
Cash flow	72%	-	53%	95%	-	30%
Proceeds from DRIP and Rights Plan	28%	5%	22%	5%	9%	8%
Proceeds from equity offering	-	-	-	-	40%	28%
Debt	-	95%	25%	-	51%	34%
	100%	100%	100%	100%	100%	100%

ARC expects to undertake significant development activities again in 2007 resulting in a \$360 million capital budget. The Trust plans to drill 275 gross wells (225 net wells) on operated properties in 2007, allocate \$6.5 million to Enhanced Oil Recovery initiatives such as carbon dioxide (“CO₂”) injection, continue to research Natural Gas from Coal (“NGC”) opportunities and develop the recently acquired Manitoba properties.

Long-Term Investment

During the second quarter of 2006, the Trust made a \$20 million investment in the shares of a private company that is involved in the acquisition of oil sands leases with development potential. At year end, the Trust holds less than a two per cent interest in the company and has the intent of holding the shares for investment purposes.

The investment in the shares of the private company has been considered to be a related party transaction due to common directorships of the Trust, the private company and the manager of a private equity fund that holds shares in the private company. In addition, certain directors and officers of the Trust have minor direct and indirect shareholdings in the private company. All of the interested directors declared their interest and the investment was approved unanimously by the directors of the Trust not including the interested directors. The \$20 million investment was part of a \$325 million private placement of the private company.

Asset Retirement Obligation and Reclamation Fund

At December 31, 2006, the Trust has recorded an Asset Retirement Obligation (“ARO”) of \$177.3 million (\$165.1 million at December 31, 2005) for future abandonment and reclamation of the Trust’s properties. The ARO increased slightly in 2006 as a result of wells drilled in the year and property and corporate acquisitions completed in 2006. The ARO further increased by \$11.1 million for accretion expense in 2006 (\$5.2 million in 2005) and was reduced by \$10.6 million (\$4.9 million in 2005) for actual abandonment expenditures incurred in 2005. The Trust did not record a gain or loss on actual abandonment expenditures incurred as the costs closely approximated the liability value included in the ARO.

As a result of the Redwater acquisition in December 2005, the Trust set up a new restricted reclamation fund (the “Redwater Fund”) in 2006 to fund future abandonment obligations attributed to the Redwater properties. The Trust makes annual contributions to the Redwater fund and may utilize the funds only for abandonment activities for the Redwater property. With the addition of the Redwater Fund, the Trust now maintains two reclamation funds which together held \$30.9 million of money market instruments at December 31, 2006. Future contributions for the two funds will vary over time in order to provide for the total estimated future abandonment and reclamation costs that are to be incurred upon abandonment of the Trust’s properties. The Trust currently estimates that \$230 million will be contributed to the funds over the next 50 years to provide for future abandonment and reclamation costs.

In total, ARC contributed \$12.1 million cash to its reclamation funds in 2006 (\$6 million in 2005) and earned interest of \$1 million (\$0.8 million in 2005) on the fund balances. The increase in funding is attributed to the Redwater fund. The fund balances were reduced by \$5.7 million for cash-funded abandonment expenditures 2006 (\$4.6 million in 2005).

A breakdown of the Trust's capital structure is as follows as at December 31, 2006 and 2005:

Capitalization, Financial Resources and Liquidity

Capital Structure and Liquidity (\$ millions except per unit and per cent amounts)	2006	2005
Revolving credit facilities	426.1	258.5
Senior secured notes	261.0	268.2
Working capital deficit excluding short-term debt ⁽¹⁾	52.0	51.4
Net debt obligations	739.1	578.1
Units outstanding and issuable for exchangeable shares (thousands)	207.2	202.0
Market price per unit at end of year	22.30	26.49
Market value of units and exchangeable shares	4,620.0	5,352.0
Total capitalization ⁽²⁾	5,359.1	5,930.1
Net debt as a percentage of total capitalization	13.8%	9.7%
Net debt obligations	739.1	578.1
Cash flow from operations	760.6	639.5
Net debt to cash flow	1.0	0.9

⁽¹⁾ The working capital deficit excludes the balances for commodity and foreign currency contracts.

⁽²⁾ Total capitalization as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Total capitalization is not intended to represent the total funds from equity and debt received by the Trust.

The increase in net debt to total capitalization in 2006 is attributed to the devaluation of the trust unit price following the Federal Government's proposed Trust taxation announcement and an increase in debt. Prior to the announcement, the trust unit price was \$27.56 per unit and total capitalization approximated \$6.3 billion. The devaluation of the unit price resulted in an approximate 20 per cent decline in market capitalization resulting in a higher net debt to total capitalization ratio.

The Federal Government's proposed Trust taxation announcement also caused increased market uncertainty pertaining to the future of the trust sector. This market uncertainty is diminishing over time, however it is our assessment that the Trust's ability to raise equity by issuing new trust units in the market has been diminished. The Government released guidelines regarding trust growth that limits expansion via acquisitions in 2007 to 40 per cent of the Trust's market capitalization as at October 31, 2006. We believe the 40 per cent limit is in excess of what the Trust could raise in the equity markets on a prudent basis. Management's assessment is that the Trust's ability to raise new equity would be dependant on financial market conditions at the time and the nature of the use of proceeds.

The Trust has a syndicated three year revolving credit facility allowing for maximum borrowing of up to \$572 million. The debt is secured by all the Trust's oil and gas properties and has the following major covenants:

Covenant	Position as at December 31, 2006
Long-term debt and letters of credit not to exceed three times annualized net income before non-cash items and interest expense	Long-term debt and letters of credit of 0.9 times annualized net income before non-cash items and interest expense
Long-term debt, letters of credit and subordinated debt not to exceed four times annualized net income before non-cash items and interest expense	Long-term debt, letters of credit and subordinated debt of 0.9 times annualized net income before non-cash items and interest expense
Long-term debt and letters of credit not to exceed 50 per cent of the sum of the book of value of unitholders' equity, long-term debt, letters of credit, and subordinated debt	Long-term debt and letters of credit of 26.8 per cent of the sum of unitholders' equity, long-term debt, letters of credit, and subordinated debt

As indicated by the above covenants, the Trust has additional potential borrowing capacity above the \$572 credit facility, however the Trust's objective is to limit debt to under 2.0 times cash flow from operations and 20 per cent of total capitalization.

In the event that the Trust enters into a material acquisition whereby the purchase price exceeds 10 per cent of the book value of the Trust's assets, the ratios in the first two covenants above are increased to 3.5 and 5.5 times, respectively. The Trust had \$4.7 million of letters of credit outstanding at December 31, 2006 and no subordinated debt. As at December 31, 2006, the Trust was in compliance with all covenants.

In addition to the \$572 million credit facility, the Trust has issued senior secured notes which do not reduce the available borrowings under the credit facility.

Net debt obligations increased by \$161 million in 2006 to \$739.1 million as a result of significant capital and acquisition activity in the year that resulted in a working capital deficit and the majority of acquisitions having been funded with debt. The Trust funded 72 per cent of its 2006 capital development program of \$364.5 million with cash flow and the remaining \$101.2 million was funded with proceeds from the DRIP and employee rights plan. The Trust funded \$125 million of the 2006 acquisitions with debt and the remaining \$6.8 million was funded with proceeds from the DRIP and Employee Rights program.

The Trust intends to finance its \$360 million 2007 capital program with cash flow and the proceeds of the distribution reinvestment program with any remainder being financed with debt.

Unitholders' Equity

At December 31, 2006, there were 207.2 million units issued and issuable for exchangeable shares, an increase of 5.2 million units from December 31, 2005. The increase in number of units outstanding is mainly attributable to the 3.9 million units issued pursuant to the DRIP during 2006 at an average price of \$24.67 per unit.

The Trust had 0.4 million rights outstanding as of December 31, 2006 under an employee plan where further rights issuances were discontinued in 2004. The rights have a five-year term and vest equally over three years from the date of grant. The majority of rights vested on May 6, 2006. The remaining rights may be purchased at an average adjusted exercise price of \$9.47 per unit as at December 31, 2006. All but 6,000 of the rights were fully vested at December 31, 2006 and the remainder will vest on March 22, 2007. The contractual life of the rights varies by series but all will expire on or before March 22, 2009.

The Whole Unit Plan introduced in 2004 is a cash compensation plan for employees, officers and directors of the Trust and does not involve any units being issued from treasury. The Trust has made provisions whereby employees may elect to have units purchased for them on the market with the cash received upon vesting.

Unitholders electing to reinvest distributions or make optional cash payments to acquire units from treasury under the DRIP may do so at a five per cent discount to the prevailing market price with no additional fees or commissions. During the 2006, the Trust raised proceeds of \$96.1 million and issued 3.9 million trust units pursuant to the DRIP.

Cash Distributions

ARC declared cash distributions of \$484.2 million (\$2.40 per unit), representing 64 per cent of 2006 cash flow from operations compared to cash distributions of \$376.6 million (\$1.99 per unit), representing 59 per cent of cash flow from operations in 2005. The remaining 36 per cent of 2006 cash flow (\$276.4 million) was used to fund 72 per cent of ARC's 2006 capital expenditures and make contributions, including interest, to the reclamation fund (\$13.2 million).

Monthly cash distributions for 2006 were \$0.20 per unit. Revisions, if any, to the monthly distribution are normally announced on a quarterly basis in the context of prevailing and anticipated commodity prices at that time.

The following items may be deducted from cash flow to arrive at cash distributions to unitholders:

- An annual contribution to the reclamation funds and interest earned on the fund balances. The reclamation funds are segregated bank accounts or subsidiary trusts and the balances will be drawn on in future periods as the Trust incurs abandonment and reclamation costs over the life of its properties. The contribution level is reviewed annually based on a detailed assessment of the Trust's total future abandonment obligation, an estimated return based on current interest rates and a future funding period approximating 50 years. The funding amount is approved by the Health, Safety and Environment committee. As future abandonment and reclamation obligations will be settled with reclamation fund balances over the life of the properties, the Trust does not anticipate any separate deductions from cash flow for abandonment and reclamation costs. The annual contribution was \$12.1 million in 2006 or two per cent of cash flow and will vary in future periods depending on acquisition and capital development activity and abandonment cost estimates to reclaim the Trust's oil and natural gas properties. The most significant annual contributions to the reclamation funds are expected to occur in years 2007 through 2015. The 2007 contribution is currently estimated to be \$12 million.
- The portion of capital expenditures that are funded with cash flow. The Trust's distribution policy guideline is to withhold at least 20 per cent of cash flow to fund a portion of capital expenditures. In 2006, the Trust withheld 34 per cent of 2006 cash flow to fund 72 per cent of the capital program excluding acquisitions. The objective of the Trust's capital expenditure program is to replace natural production declines resulting in stable production. This level of capital expenditures may not replace the Trust's reserves produced out during the period, but rather bring non-producing reserves on stream.

- Debt principal repayments to the extent that required principal repayment cannot be refinanced by other means. The Trust's current debt level is well within the covenants specified in the debt agreements and, accordingly, there are no current mandatory requirements for repayment. Refer to the "Capital Structure and Liquidity" section of this MD&A for a detailed review of the debt covenants.
- Income taxes that are not passed on to unitholders. The Trust has a liability for future income taxes due to the excess of book value over the tax basis of the assets of the Trust and its corporate subsidiaries. The Trust currently minimizes or eliminates cash income taxes in corporate subsidiaries by maximizing deductions, however in future periods there may be cash income taxes if deductions are not sufficient to eliminate taxable income and if proposed changes in Trust taxation are enacted. Taxability of the Trust is currently passed on to unitholders in the form of taxable distributions whereby corporate income taxes are eliminated at the Trust level. If the proposed Trust taxation legislation is enacted, the Trust anticipates that the resulting tax commencing in 2011 at the Trust level would decrease cash flow and thus reduce cash distributions to unitholders.
- Working capital requirements as determined by the Trust. Certain working capital amounts may be deducted from cash flow, however such amounts would be minimal and the Trust does not anticipate any such deductions in the foreseeable future.
- The Trust has certain obligations for future payments relative to employee long-term incentive compensation. Presently, the Trust estimates that \$18.2 million to \$58.6 million will be paid out pursuant to such commitments in 2007 through 2009 subject to vesting provisions and future performance of the Trust. These amounts will reduce cash flow and in turn cash distributions in future periods.

Cash flow and cash distributions in total and per unit were as follows:

Cash flow and distributions (\$ millions and \$ per unit)	(\$ million)			(\$ per unit)		
	2006	2005	% Change	2006	2005	% Change
Cash flow from operations	760.6	639.5	19	3.72	3.35	11
Reclamation fund contributions ⁽¹⁾	(13.2)	(6.8)	94	(0.06)	(0.04)	50
Capital expenditures funded with cash flow	(263.2)	(256.1)	3	(1.28)	(1.34)	(4)
Other ⁽²⁾	-	-	-	0.02	0.02	-
Cash distributions	484.2	376.6	29	2.40	1.99	21

⁽¹⁾ Includes interest income earned on the reclamation fund balances that is retained in the reclamation funds.

⁽²⁾ Other represents the difference due to cash distributions paid being based on actual units at each distribution date whereas per unit cash flow, reclamation fund contributions and capital expenditures funded with cash flow are based on weighted average trust units in the year plus units issuable for exchangeable shares at year end.

The Trust continually assesses distribution levels, in light of commodity prices and production volumes, to ensure that distributions are in line with the long-term strategy and objectives of the Trust as per the following guidelines:

- To maintain a level of distributions that, in the opinion of Management and the Board of Directors, are sustainable for a minimum period of six months. The Trust's objective is to normalize the effect of volatility of commodity prices rather than to pass on that volatility to unitholders in the form of fluctuating monthly distributions.
- To ensure that the Trust's payout ratio does not exceed 80 per cent on an annual basis. The Trust believes that a portion of cash flow should be reinvested in capital development activities in order to offset, in part, the natural production declines of the Trust's assets over the long-term. The use of cash flow to fund capital development activities reduces the requirements of the Trust to use debt and equity to finance these expenditures. In 2006 the Trust funded 72 per cent of capital development activities with 34 per cent of cash flow. The actual amount of cash flow withheld to fund the Trust's capital expenditure program is dependent on the commodity price environment and is at the discretion of the Board of Directors.

In order to set distributions to meet the above noted objectives, the Trust maintains an annual cash flow forecast that incorporates actual results of the Trust and market conditions. An annual distribution is determined based on the Trust's objectives of a maximum annual payout ratio of 80 percent, a minimum of 20 per cent of annual cash flow to fund capital expenditures, and a minimum annual contribution to the reclamation funds. As market conditions change, the forecast is updated to assess whether there should be a change in distribution levels. A change to distributions is proposed only if there is a reasonable probability that the revised distribution may be maintained for a minimum six-month period. If distribution levels remain the same, the difference in cash flow between estimated and actual results is reflected in the level of cash funded capital expenditures.

The actual amount of future monthly cash distributions are proposed by management and are subject to the approval and discretion of the Board of Directors. The Board reviews future cash distributions in conjunction with their review of quarterly financial and operating results.

Monthly cash distributions for the first quarter of 2007 have been set at \$0.20 per unit subject to monthly review based on commodity price fluctuations. Revisions, if any, to the monthly distribution are normally announced on a quarterly basis in the context of prevailing and anticipated commodity prices at that time.

Historical Cash Distributions by Calendar Year

The following table presents cash distributions paid and payable for each calendar period.

Calendar Year	Distributions	Taxable Portion	Return of Capital
2007 YTD ⁽²⁾	0.20	0.20 ⁽²⁾	0.00 ⁽²⁾
2006 ⁽¹⁾	2.60	2.55 ⁽³⁾	0.05 ⁽³⁾
2005	1.94	1.90	0.04
2004	1.80	1.69	0.11
2003	1.78	1.51	0.27
2002	1.58	1.07	0.51
2001	2.41	1.64	0.77
2000	1.86	0.84	1.02
1999	1.25	0.26	0.99
1998	1.20	0.12	1.08
1997	1.40	0.31	1.09
1996	0.81	-	0.81
Cumulative	\$ 18.83	\$ 12.09	\$ 6.74

(1) Based on cash distributions paid and payable in 2006.

(2) Based on cash distributions declared at January 31, 2007 and estimated taxable portion of 2007 distributions of 98 per cent.

(3) Based on taxable portion of 2006 distributions of 98 per cent.

2006 Monthly Cash Distributions

Actual cash distributions paid and payable in 2006 along with relevant payment dates were as follows:

Ex-distribution date	Record date	Distribution payment date	Total distribution
December 28, 2005	December 31, 2005	January 16, 2006	0.20
January 27, 2006	January 31, 2006	February 15, 2006	0.20
February 24, 2006	February 28, 2006	March 15, 2006	0.20
March 29, 2006	March 31, 2006	April 17, 2006	0.20
April 26, 2006	April 30, 2006	May 15, 2006	0.20
May 29, 2006	May 31, 2006	June 15, 2006	0.20
June 28, 2006	June 30, 2006	July 17, 2006	0.20
July 27, 2006	July 31, 2006	August 15, 2006	0.20
August 29, 2006	August 31, 2006	September 15, 2006	0.20
September 27, 2006	September 30, 2006	October 16, 2006	0.20
October 27, 2006	October 31, 2006	November 15, 2006	0.20
November 28, 2006	November 30, 2006	December 15, 2006	0.20
December 27, 2006	December 31, 2006	January 15, 2007	0.20
Total 2006			2.60

Please refer to the Trust's website at www.arcenergytrust.com for details on distributions dates for 2007.

Taxation of Cash Distributions

Cash distributions comprise a return of capital portion (tax deferred) and a return on capital portion (taxable). The return of capital component reduces the cost basis of the units held. For 2006, cash distributions paid in the calendar year will be 98 per cent return on capital (taxable) and two per cent return of capital (tax deferred). For a more detailed breakdown, please visit our website at www.arcenergytrust.com.

The proposed Trust taxation announced by the Federal Government on October 31, 2006 and subsequent draft legislation would result in income taxes being imposed at the Trust level on distributions paid to unitholders effective January 1, 2011. The Trust is currently assessing the proposals and the potential implications to the Trust in future periods.

Deficit

During the second quarter, presentation changes were made to combine the previously reported accumulated earnings and accumulated cash distribution figures on the balance sheet into a single deficit balance. The Trust has historically paid cash distributions in excess of accumulated earnings as cash distributions are based on cash flow generated in the current period, while accumulated earnings are based on cash flow generated in the current period less a depletion and depreciation expense recorded on the original property, plant, and equipment investment. Numbers presented for comparative purposes have been restated to reflect this change in presentation.

Contractual Obligations and Commitments

The Trust has contractual obligations in the normal course of operations including purchase of assets and services, operating agreements, transportation commitments, sales commitments, royalty obligations, and lease rental obligations. These obligations are of a recurring and consistent nature and impact cash flow in an ongoing manner. The Trust also has contractual obligations and commitments that are of a less routine nature as disclosed in the following table.

Commitments (\$ millions)	Payments due by period				Total
	2007	2008 – 2009	2010-2011	Thereafter	
Debt repayments	8.0	451.2	53.1	174.8	687.1
Interest payments ⁽¹⁾	11.3	21.5	18.1	20.8	71.7
Reclamation fund contributions ⁽²⁾	6.0	11.1	9.5	76.2	102.8
Purchase commitments	12.6	8.4	3.4	6.8	31.2
Operating leases	5.3	9.9	5.0	-	20.2
Derivative contract premiums ⁽³⁾	12.4	3.3	-	-	15.7
Retention bonuses	1.0	-	-	-	1.0
Total contractual obligations	56.6	505.4	89.1	278.6	929.7

⁽¹⁾ Fixed interest payments on the Senior Secured Notes.

⁽²⁾ Contribution commitments to a restricted reclamation fund associated with the Redwater property acquired in 2005.

⁽³⁾ Fixed premiums to be paid in future periods on certain commodity derivative contracts.

The above noted derivative contract premiums are part of the Trust's commitments related to its risk management program. In addition to the above premiums, the Trust has commitments related to its risk management program. As the premiums are part of the underlying derivative contract, they have been recorded at fair market value at December 31, 2006 on the balance sheet as part of commodity and foreign currency contracts.

The Trust enters into commitments for capital expenditures in advance of the expenditures being made. At a given point in time, it is estimated that the Trust has committed to capital expenditures equal to approximately one quarter of its capital budget by means of giving the necessary authorizations to incur the capital in a future period. The Trust's 2007 capital budget has been approved by the Board at \$360 million. This commitment has not been disclosed in the commitment table as it is of a routine nature and is part of normal course of operations for active oil and gas companies and trusts.

The Trust is involved in litigation and claims arising in the normal course of operations. Management is of the opinion that pending litigation will not have a material adverse impact on the Trust's financial position or results of operations and therefore the following table does not include any commitments for outstanding litigation and claims.

The Trust has certain sales contracts with aggregators whereby the price received by the Trust is dependent upon the contracts entered into by the aggregator. This commitment has not been disclosed in the commitment table as it is of a routine nature and is part of normal course of operations.

Off Balance Sheet Arrangements

The Trust has certain lease agreements which aggregate to less than \$1 million and were entered into in the normal course of operations. All leases have been treated as operating leases whereby the lease payments are included in operating expenses or G&A expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases in the balance sheet as of December 31, 2006.

The Trust's long-term electricity hedge and interest rate hedges have not been recorded as an asset or liability on the balance sheet as they qualify as effective accounting hedges.

The Trust entered into agreements to pay premiums pursuant to certain crude oil derivative put contracts. Premiums of \$15.7 million will be paid in 2007 through 2009 for the put contracts in place at December 31, 2006. As the premiums are part of the underlying derivative contract, they have been recorded at fair market value at December 31, 2006 on the balance sheet.

Critical Accounting Estimates

The Trust has continuously evolved and documented its management and internal reporting systems to provide assurance that accurate, timely internal and external information is gathered and disseminated.

The Trust's financial and operating results incorporate certain estimates including:

- estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;
- estimated capital expenditures on projects that are in progress;
- estimated depletion, depreciation and accretion that are based on estimates of oil and gas reserves that the Trust expects to recover in the future;
- estimated fair values of derivative contracts that are subject to fluctuation depending upon the underlying commodity prices and foreign exchange rates;
- estimated value of asset retirement obligations that are dependent upon estimates of future costs and timing of expenditures; and
- estimated future recoverable value of property, plant and equipment and goodwill.

The Trust has hired individuals and consultants who have the skills required to make such estimates and ensures that individuals or departments with the most knowledge of the activity are responsible for the estimates. Further, past estimates are reviewed and compared to actual results, and actual results are compared to budgets in order to make more informed decisions on future estimates.

The ARC leadership team's mandate includes ongoing development of procedures, standards and systems to allow ARC staff to make the best decisions possible and ensuring those decisions are in compliance with the Trust's environmental, health and safety policies.

Internal Controls Update

On July 31, 2002, the United States Congress enacted the Sarbanes-Oxley Act ("SOX"). SOX applies to all companies registered with the Securities and Exchange Commission ("SEC"). Although ARC is not listed on a US stock exchange, the Trust is registered with the SEC as a result of having acquired Startech Energy Inc. in 2001 and therefore was required to comply with section 404 of the SOX legislation as at December 31, 2006 and each year thereafter.

There are various components to the SOX legislation, however the most comprehensive is Section 404 "Internal Controls Over Financial Reporting". Section 404 requires that management undertake the following:

- identify and document internal controls that impact financial reporting;
- assess the effectiveness of those internal controls;
- remediate any deficiencies in internal controls and/or implement any required controls that are not already in place;
- test the internal controls to ensure that they are operating effectively; and
- issue a report, to be signed by the Chief Operating Officer and the Chief Financial Officer, on management's assessment of the effectiveness of internal controls and communicate any material weaknesses.

Internal control over financial reporting is a process designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely information. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Management has assessed the effectiveness of the company's internal control over financial reporting based on the framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and concluded that the company's internal control over financial reporting was effective as of December 31, 2006. Management's assessment of the effectiveness of the company's internal control over financial reporting as of December 31, 2006 has been audited by Deloitte & Touche LLP, as reflected in their report for 2006.

As of December 31, 2006, an internal evaluation was carried out of the effectiveness of the Trust's disclosure controls and procedures as defined in Rule 13a-15 under the US Securities Exchange Act of 1934, also known as SOX 302.

Based on that evaluation, the President and Chief Executive Officer and Chief Financial Officer concluded that the disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that the Trust files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the rules and forms of the SEC. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that the information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act is accumulated and communicated to the Trust's management, including the senior executive and financial officers, as appropriate to allow timely decisions regarding the required disclosure.

In addition to SOX, ARC is required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings", otherwise referred to as Canadian SOX ("C-Sox"). The Canadian requirements closely parallel the SEC's certification rules, however, currently there is no requirement to have the external auditor opine on the Trust's internal controls or management's assessment thereof. ARC has complied with this legislation by filing bare interim certificates and a full annual certificate with no modifications in conjunction with the December 31, 2006 year end. The 2006 certificate requires that the Trust disclose in the annual MD&A any changes in the Trust's internal control over financial reporting that occurred during the period that has materially affected, or is reasonably likely to materially affect the Trust's internal control over financial reporting. The Trust confirms that no such changes were made to the internal controls over financial reporting during 2006.

Financial Reporting Update

During 2006, the Trust commenced a review of the new CICA Handbook section 3855 "Financial Instruments – Recognition and Measurement", section 1530 "Comprehensive Income" and section 3865 "Hedges" that deal with the recognition and measurement of financial instruments at fair value and comprehensive income. The new standards are intended to harmonize Canadian standards with United States and international accounting standards. The new standards are effective for annual and interim periods in fiscal years beginning on or after October 1, 2006. These new standards will impact the Trust in 2007 and are currently being reviewed to assess their impact.

Objectives and 2007 Outlook

Sustainability

It is the Trust's objective to provide superior and sustainable long-term returns to unitholders by focusing on the key strategic objectives of the business plan. The Trust acquires, develops and optimizes oil and natural gas properties in predominantly mature areas to generate a cash flow stream. Due to natural production declines, the Trust must continually develop its reserves and/or acquire new reserves in an effort to maintain reserves, production and cash flow levels on which distributions are paid. The trust facilitates this by withholding a portion of cash flow to fund a portion of ongoing capital development activities and maintaining moderate debt levels; this is evidenced by the Trust's low payout ratio. Oil and gas royalty trusts hold assets that are depleting and unitholders should expect production, revenue, cash flow and distributions to decline over the long-term if reserves cannot be economically replaced. The Trust has an inventory of internal development prospects that will enable the Trust to maintain production and reserves for a minimum period of two years. The Trust anticipates employing a conservative payout policy to provide for cash funding of a portion of ongoing capital development programs and maintaining low debt levels to facilitate further growth. The Trust measures its sustainability and success in terms of per unit cash distributions, production, reserves, and cash flow in addition to the ability to maintain low debt levels and the annual replacement of reserves.

Following is a summary of the historical debt-adjusted production and reserves per unit and reserve life index on which the Trust assesses performance and sustainability:

Per trust unit ratios	2006	2005	2004	2003	2002	5 Year Total
Production per unit ⁽¹⁾ :						
Unadjusted	0.31	0.29	0.31	0.35	0.35	-
Debt-adjusted ⁽³⁾	0.27	0.26	0.28	0.31	0.29	-
Normalized ⁽⁴⁾	0.31	0.31	0.33	0.38	0.33	-
Reserves per unit ⁽²⁾ :						
Unadjusted	1.38	1.42	1.29	1.37	1.47	-
Debt-adjusted ⁽³⁾	1.19	1.28	1.20	1.25	1.19	-
Normalized ⁽⁴⁾	1.38	1.49	1.39	1.44	1.38	-
Reserve life index ⁽⁵⁾	12.4	12.9	12.2	12.4	11.8	-
Cash flow per unit	\$3.72	\$3.35	\$2.41	\$2.56	\$1.87	\$13.91
Cash distributions per unit	\$2.40	\$1.99	\$1.80	\$1.80	\$1.56	\$9.55
Payout ratio per cent ⁽⁶⁾	64	59	74	71	82	70
Per cent of cash flow retained	36	41	26	29	18	30

- (1) Represents daily average production per thousand units. Calculated based on annual daily average production divided by weighted average trust units including trust units issuable for exchangeable shares.
- (2) Calculated based on proved plus probable reserves divided by period end trust units including trust units issuable for exchangeable shares.
- (3) Debt-adjusted indicates that all years as presented have been adjusted to reflect a nil net debt to capitalization. It is assumed that additional trust units were issued at a period end price for the reserves per unit calculation and at an annual average price for the production per unit calculation in order to reduce the net debt balance to zero in each year. The debt-adjusted amounts are presented to enable comparability of annual per unit values.
- (4) Normalized indicates that all years as presented have been adjusted to reflect a net debt to capitalization of 14 per cent as per December 31, 2006. It is assumed that additional trust units were issued (or repurchased) at a period end price for the reserves per unit calculation and at an annual average price for the production per unit calculation in order to reduce the net debt balance to 14 per cent of total capitalization each year. The normalized amounts are presented to enable comparability of annual per unit values.
- (5) Calculated based on proved plus probable reserves divided by annual 2007 production estimate of 63,000 boe per day for 2006 RLI.
- (6) Calculated as cash distributions divided by cash flow from operations.

During the 2002 to 2006 time period the trust's normalized production per unit has decreased only slightly from 0.33 to 0.31 boe of daily average production per thousand trust units and normalized reserves per unit have remained constant during this time at 1.38 boe of proved plus probable reserves per trust unit. The maintenance of production and reserves per unit occurred even with the payout of \$1.7 billion of cash distributions (\$9.55 per trust unit and 70 per cent of cash flow) during the 2002 through 2006 time period. This indicates that the Trust has continually grown production levels to offset natural production declines and developed and grown its reserve base. The debt-adjusted production per unit is a key measure as it indicates the ability to generate cash flow from core operations which in turn impacts the level of cash that may be distributed to unitholders. The Trust expects to replace production in 2007 from internal development opportunities.

To compare the Trust's results with oil and gas companies that retain all of their cash flow to grow production and reserves, the Trust looks at normalized and distribution-adjusted production and reserves per unit which calculates the total reserves and production per initial investment with the assumption that distributions are reinvested through the DRIP plan. Consequently, the reserves and production per initial investment increase over time as the investor's number of trust units increase with distribution reinvestment. The Trust's normalized daily average production per initial investment has increased from 0.33 boe per thousand trust units in 2002 to 0.56 in 2006, while normalized reserves per initial investment have increased from 1.53 boe at January 1, 2002 to 2.50 boe at December 31, 2006. The increase is attributed to the DRIP factor whereby one trust unit purchased on January 1, 2002 would have grown to 1.81 trust units on December 31, 2006. A unitholder can replicate this by participating in the DRIP so that the number of units they own increases over time.

The Trust's reserve life index ("RLI") increased to 12.4 years in 2006 from 11.8 years in 2002. The RLI is a measure of the remaining average life of the reserves based on a current production estimate for 2007 of 63,000 boe per day. The Trust's high RLI is indicative of the high quality of assets and long reserve life of the properties. The acquisition of the Redwater and NPCU properties in 2005 resulted in an increase in the RLI due to the long reserve life of the properties. A high RLI is key for a royalty trust as it indicates the potential sustainability of production levels and cash flow over a longer period of time.

The Trust's distribution policy centres around the goal of providing a consistent and sustainable level of distributions to unitholders and to provide for future growth. The low payout ratio is indicative of the Trust's commitment to fund ongoing development activities with cash flow to enable long-term sustainability. A high payout ratio indicates that ongoing capital development activities must be either debt or equity financed. The Trust's payout ratio has declined over time as the Trust has addressed the issue of long-term sustainability while setting distribution levels.

An additional measure of sustainability is the comparison of net income to cash distributions. Net income incorporates all costs including depletion expense and other non-cash expenses whereas cash flow from operations measures the cash generated in a given period before the cost of the associated reserves. Therefore, net income may be more representative of the profitability of the entity and thus a relevant measure against which to measure cash distributions to illustrate sustainability. As net income is sensitive to fluctuations in commodity prices, it is expected that there will be deviations between annual net income and cash distributions. The following table illustrates the annual excess or shortfall of cash distributions to net income as a measure of long-term sustainability.

Net income and cash distributions (\$ millions except per cent)	2006	2005	2004	2003	2002	5 Year Total
Net income	460.1	356.9	241.7	284.6	70.0	1,431.3
Cash distributions	484.2	376.6	330.0	279.3	183.6	1,653.7
Excess (shortfall)	(24.1)	(19.7)	(88.3)	5.3	(113.6)	(222.4)
Excess (shortfall) as per cent of net income	(5%)	(6%)	(37%)	2%	(62%)	(16%)
Payout per cent	64%	59%	74%	71%	82%	70%

During 2002 through 2004, there was significant volatility in commodity prices and it was management's decision to maintain distributions at a consistent level during that time as it was perceived that the decline in commodity prices was temporary. Management's decision to lower payout ratios over time is illustrated in the table as cash distributions more closely approximate net income in 2005 and 2006.

Returns to Unitholders and Proposed Federal Legislation to Tax Income Trusts

The Trust has provided unitholders with the following one, three and five year returns, including reinvestment of distributions:

Total Returns (\$ per unit except for per cent)	One Year		Three Year		Five Year	
Distributions per unit	\$	2.40	\$	6.19	\$	9.55
Capital appreciation per unit	\$	(4.19)	\$	7.56	\$	10.20
Total return per unit	\$	(1.79)	\$	13.75	\$	19.75
Annualized total return per unit	%	(8.0)	%	26.7	%	26.5

To the end of 2006, the Trust has provided cumulative cash distributions of \$18.63 per unit and capital appreciation of \$12.30 per unit for a total return of \$30.93 per unit (23.8 per cent annualized total return) for unitholders who invested in the Trust at inception in 1996. The Trust has announced 2007 cash distributions of \$0.20 per unit per month through March 2007.

During 2006, the announcement and subsequent introduction of proposed legislation regarding taxation of Trusts resulted in a significant decline in trust unit prices throughout the industry. Consequently, many trusts have reported a negative total return to unitholders in 2006 as a result of the decline in trust unit prices immediately following the announcement. ARC's return to unitholders was negative eight per cent in 2006 as a result of a 20 per cent decline in the trust unit price following the Federal Government announcement on October 31, 2006. The Trust had reached a historic high unit price of \$30.74 in August 2006. Annual distributions to unitholders of \$2.40 per trust unit are our highest to date.

Despite the devaluation of the trust unit price following the proposed Trust taxation announcement, the Trust's business remains unchanged and the Trust is still a prospering and sustainable entity with no change to the core operations. Subsequent to the announcement, the Trust has been actively researching alternatives regarding the structure and business strategy leading up to the implementation of the proposed tax in 2011. Under the current proposed legislation, the most viable option appears to be conversion to a corporate entity no earlier than January 1, 2011 due to the punitive financial impact that the taxation would have on the trust structure. However, given that the legislation has not been officially enacted, the Trust has not made any conclusive decisions with respect to the strategy over the next four years as we feel it is prudent to await the final legislation and fully research all alternatives before making a final decision. The Trust is working closely with legal and business advisors as to the potential future structure and direction of the Trust in an effort to maximize the value to unitholders, and to choose a direction which is in the best interest of its unitholders.

ARC plans to proceed with its full \$360 million capital expenditure budget for 2007 which consists of a robust drilling and development program on its diverse asset base. The 2007 capital budget is being deployed on well tie-ins and other facility related costs, a balanced drilling program of low and moderate risk wells and the acquisition of undeveloped land. The Trust continues to focus on major properties with significant upside, with the objective to replace production declines through internal development opportunities. The 2007 capital expenditure budget anticipates the drilling of 225 net operated wells and the addition of 11,000 boe per day of new production from the capital development program to replace declines at existing properties. The 2007 capital budget also allows for a portion of spending to further research and pursue Enhanced Recovery Initiatives such as CO₂ injection and NGC development. Despite the Trust's active fourth quarter, there was a general slow down in activity levels for the industry late in 2006. The Trust expects that with the lower activity levels and decreased demand for industry services that costs will moderate slightly in 2007. Current low debt levels and a strong working capital position provide the Trust with the financial flexibility to fund the 2007 capital expenditure program.

The Trust continually looks to execute minor property acquisitions and dispositions in order to enhance and streamline the Trust's portfolio of oil and natural gas assets. The Trust continually reviews potential acquisitions of both conventional oil and natural gas reserves and in the broader energy industry. The Federal Government issued guidance with respect to limitations on future growth of the Trust in conjunction with the proposed Trust taxation announcement. The Trust does not anticipate that the guidelines will impair the Trust's ability to annually replace or grow reserves in the next four years as the guidelines allow sufficient growth targets. Key attributes of the future growth constraints are as follows:

- Trusts may grow in size by 100 per cent cumulatively for the period 2007 through 2010 as measured by the value of equity based on the October 31, 2006 market capitalization. The cumulative limit starts at 40 per cent in 2007 and increases by 20 per cent per year in 2008 through 2010.
- Merger of two Trusts will not be impacted by the growth limitations.
- The growth limits are not impacted by non-convertible debt-financed growth but rather focus solely on the issuance of equity to facilitate growth.

The Trust will continue to assess accretive acquisition opportunities. Acquisitions are evaluated internally and acquisitions in excess of \$25 million are subject to Board approval.

Accomplishment of 2006 Objectives

The key future objectives of the Trust's business plan, as identified below, are reviewed annually by the Board. The Trust was successful in meeting all of its objectives in 2006 as individually addressed below. They continue to be key objectives for 2007.

- **Annual reserves replacement** – The Trust's proved plus probable reserves were effectively maintained as December 31, 2006 reserves of 286.1 mmbob were within one per cent of the 287 mmbob recorded as at December 31, 2005. The reserves were maintained through a combination of the \$364.5 million 2006 capital development program and corporate and property acquisitions (net of dispositions) of \$131.8 million.
- **Ensuring acquisitions are strategic and enhance unitholder returns** – The Trust added producing properties in Manitoba to its asset base in 2006 and also increased its land ownership in certain core areas in 2006 in an effort to increase its inventory of future development opportunities. In addition, the Redwater property acquired in 2005 provided many opportunities to ARC due to the optimization potential of this long-life, light oil property. Since acquisition, ARC has reactivated 95 gross wells (62 net wells) at Redwater and NPCU and increased production by approximately 580 boe per day net. ARC believes that long-life, light oil properties will provide future opportunities to enhance unitholder value through the application of tertiary recovery methods.
- **Controlling costs** – Due to the diligence of field and office operating staff, the Trust's base operating costs per boe, before the impact of higher cost acquisitions, increased by approximately five per cent over 2005 costs. Cash G&A costs in 2006 increased 18 per cent to \$1.58 per boe from \$1.34 per boe in 2005 as a result of both increased staff counts following acquisitions and increased compensation costs due to the extremely competitive marketplace for experienced staff with oil and gas expertise. The Trust believes the \$1.58 per boe cash G&A costs will be better than average for mid-sized oil and gas producers in 2006. The Trust's three year average FD&A costs of \$15.59 per boe prior to incorporating future development costs "FDC" and \$18.99 per boe with FDC are expected to approximate the industry average. The increase in FD&A costs in 2006 is considered an anomaly partly due to the large investment in strategic undeveloped land with no associated reserves. The land acquisitions provide future development opportunities and are expected to yield reserves in future periods as development occurs.
- **Conservative utilization of debt** – The Trust's net debt levels were under 14 per cent of total capitalization and debt to 2006 cash flow was slightly less than 1.0 times for the year ended 2006. With the Federal Government's proposed Trust taxation announcement, the Trust's market capitalization fell by approximately 20 per cent to \$4.5 billion whereby the net debt to total capitalization increased accordingly. The Trust's debt levels are still considered to be one of the lowest in the Trust sector.
- **Continuously developing the expertise of our staff and seeking to hire and retain the best in the industry** – The Trust runs an active training and development program for its employees and encourages personal development. The Trust continues to assess compensation levels in the industry to ensure that the Trust's compensation is competitive so as to attract and retain the best employees. The Trust's long-term incentive plan's payouts are directly tied to the Trust's performance providing alignment between employees and investors.

- **Building relationships and conducting business in a way that is viewed as fair and equitable** – ARC employees, leadership team and directors work hard to build the ARC “franchise value” through honest, transparent dealings with our business partners. “Treating all people with respect” is a key message inside and outside the organization. This basic business fundamental allows us to build enduring relationships with joint venture partners, land owners, investors, banks and lending institutions, governments and the investment community.
- **Promoting the use of proven and effective technologies** – The Trust continues to research new technologies in an effort to conduct its operations in the most efficient and cost effective manner. The Trust has committed a portion of its 2007 capital expenditure budget towards continued research into tertiary recovery methods.
- **Being an industry leader in health, safety and environmental performance** – The Trust’s primary focus continues to be on operating in a safe, reliable and responsible fashion. The Trust is committed to the platinum level of CAPP Stewardship reporting and continues to achieve reductions in greenhouse gas emissions under the Canada Climate Change VCR initiative. The Trust’s commitment to pursue additional CO₂ injection opportunities is expected to have the two-fold benefit of enhanced recovery of reserves and the capture and containment of CO₂ emissions which will benefit the environment. The Trust’s commitment to safety is evidenced by zero lost time incidents reported for employees and contract employees of the Trust in 2006.
- **Continuing to actively support local initiatives in the communities in which we live and work** – The Trust is very actively involved in charitable and philanthropic causes both in Calgary and in the rural communities in which it operates. ARC continued to be a strong supporter of the United Way, Alberta Cancer Foundation, Alberta Children’s Hospital and many community organizations in rural centres. In addition to the \$1.3 million of cash donations made to charitable organizations in 2006 the Trust also provided business expertise, employee volunteers and tangible assets as needed.

2006 Review and 2007 Guidance

Following is a summary of the Trust’s 2007 Guidance issued by way of news release on November 2, 2006 and a review of 2006 actual results compared to 2006 Guidance:

	2006 Guidance	Actual 2006	% Change	2007 Guidance
Production (boe/d)	63,000	63,056		63,000
Expenses (\$/boe):				
Operating costs	8.40	8.49	1	8.95
Transportation	0.70	0.63	(10)	0.70
G&A expenses – cash	1.65	1.58	4	2.25
G&A expenses – stock compensation plans	0.60	0.47	(22)	0.20
Interest	1.35	1.38	2	1.50
Taxes	0.02	0.01	(50)	0.00
Capital expenditures (\$ millions)	370	365	(1)	360
Weighted average trust units and units issuable (millions)	205	207	1	208

Actual 2006 results were in line with 2006 guidance with only minor exceptions as follows:

- Operating costs were slightly higher than guidance due to increased Alberta electricity rates in the fourth quarter of 2006.
- Transportation costs were lower than guidance due to lower than anticipated transportation costs in the fourth quarter on trucked volumes.
- Cash G&A expenses were lower than guidance due to higher operating recoveries attributed to high levels of capital and operating activity in the fourth quarter.
- Non-cash G&A expenses were lower than guidance due to the decline in the value of the Trust’s whole unit plan following the Federal Government’s proposed Trust taxation announcement on October 31, 2006. As the value of the whole unit plan is dependent upon the trust unit price, there was a considerable decrease in the fourth quarter non-cash whole unit plan expense.
- Interest expense was slightly higher than guidance due to increased debt levels in the fourth quarter resulting from high capital and acquisition activity which was partially funded with debt.

- Weighted average trust units were slightly higher than guidance due to the large number of units issued pursuant to the DRIP in the fourth quarter.

There have been no revisions to the 2007 Guidance estimates as originally published on November 2, 2006.

2007 Cash Flow Sensitivity

Below is a table that illustrates sensitivities to pre-hedged cash flow with operational changes and changes to the business environment:

Business Environment	Assumption	Impact on Annual Cash Flow	
		Change	\$/Unit
Oil price (US\$WTI/bbl) (1)	\$ 59.00	\$ 1.00	\$ 0.05
Natural gas price (CDN \$AECO/mcf) (1)	\$ 7.25	\$ 0.10	\$ 0.03
USD/CAD exchange rate	0.88	\$ 0.01	\$ 0.06
Interest rate on debt	5.2%	% 1.0	\$ 0.03
Operational			
Liquids production volume (bbl/d)	32,200	% 1.0	\$ 0.02
Gas production volumes (mmcf/d)	185.0	% 1.0	\$ 0.02
Operating expenses per boe	\$ 8.95	% 1.0	\$ 0.01
Cash G&A expenses per boe	\$ 2.25	% 10.0	\$ 0.02

(1) Analysis does not include the effect of hedging contracts.

Forward-Looking Statement

This discussion and analysis contains forward-looking statements as to the Trusts internal projections, expectations or beliefs relating to future events or future performance within the meaning of the “safe harbour” provisions of the United States Private Securities Litigation Reform Act of 1995 and the Securities Act (Ontario). In some cases, forward-looking statements can be identified by terminology such as “may”, “will”, “should”, “expects”, “projects”, “plans”, “anticipates” and similar expressions. These statements represent management’s expectations or beliefs concerning, among other things, future operating results and various components thereof or the economic performance of ARC Energy Trust (“ARC” or “the Trust”). The projections, estimates and beliefs contained in such forward-looking statements are based on management’s assumptions relating to the production performance of ARC’s oil and gas assets, the cost and competition for services throughout the oil and gas industry in 2007 and the continuation of the current regulatory and tax regime in Canada, and necessarily involve known and unknown risks and uncertainties, including the business risks discussed in this MD&A, which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted. The Trust does not undertake to update any forward looking information in this document whether as to new information, future events or otherwise.

Additional Information

Additional information relating to ARC can be found on SEDAR at www.sedar.com.

ANNUAL HISTORICAL REVIEW

For the year ended December 31 (CDN \$ millions, except per unit amounts)					
	2006	2005	2004	2003	2002
FINANCIAL					
Revenue before royalties	1,230.5	1,165.2	901.8	743.2	444.8
Per unit ⁽¹⁾	6.02	6.10	4.85	4.80	3.72
Cash flow	760.6	639.5	448.0	396.2	224.0
Per unit – basic ⁽¹⁾	3.72	3.35	2.41	2.56	1.87
Per unit – diluted	3.71	3.32	2.38	2.48	1.86
Net income	460.1	356.9	241.7	284.6	70.0
Per unit – basic ⁽²⁾	2.28	1.90	1.32	1.88	0.60
Per unit – diluted	2.27	1.88	1.31	1.82	0.59
Cash distributions	484.2	376.6	330.0	279.3	183.6
Per unit ⁽³⁾	2.40	1.99	1.80	1.80	1.56
Total assets	3,479.0	3,251.2	2,305.0	2,281.8	1,467.9
Total liabilities	1,550.6	1,415.5	755.7	730.0	599.3
Net debt outstanding ⁽⁴⁾	739.1	578.1	264.8	262.1	347.8
Weighted average units (millions) ⁽⁵⁾	204.4	191.2	186.1	154.7	119.6
Units outstanding and issuable at period end (millions) ⁽⁵⁾	207.2	202.0	188.8	182.8	126.4
CAPITAL EXPENDITURES					
Geological and geophysical	11.4	9.2	5.4	5.7	2.0
Land	32.4	9.1	4.1	4.0	-
Drilling and completions	240.5	191.8	140.4	106.2	70.0
Plant and facilities	77.6	55.0	41.1	36.5	14.4
Other capital	2.6	3.7	2.8	3.4	1.9
Total capital expenditures	364.5	268.8	193.8	155.8	88.3
Property acquisitions (dispositions), net	115.2	91.3	(58.2)	(161.6)	119.1
Corporate acquisitions ⁽⁶⁾	16.6	505.0	72.0	721.6	-
Total capital expenditures and net acquisitions	496.3	865.1	207.6	715.8	207.4
OPERATING					
Production					
Crude oil (bbl/d)	29,042	23,282	22,961	22,886	20,655
Natural gas (mmcf/d)	179.1	173.8	178.3	164.2	109.8
Natural gas liquids (bbl/d)	4,170	4,005	4,191	4,086	3,479
Total (boe per day 6:1)	63,056	56,254	56,870	54,335	42,425
Average prices					
Crude oil (\$/bbl)	65.26	61.11	47.03	36.90	31.63
Natural gas (\$/mcf)	6.97	8.96	6.78	6.40	4.41
Natural gas liquids (\$/bbl)	52.63	49.92	39.04	32.19	24.01
Oil equivalent (\$/boe)	53.33	56.54	43.13	37.29	28.73
RESERVES ⁽⁷⁾					
(company interest)					
Proved plus probable reserves					
Crude oil and NGL (mmbbl)	162,193	163,385	123,226	129,663	117,241
Natural gas (bcf)	743.6	741.7	724.5	720.2	408.8
Total (mboe)	286,125	286,997	243,974	249,704	185,371
TRUST UNIT TRADING					
(based on intra-day trading)					
Unit prices					
High	30.74	27.58	17.98	14.87	13.44
Low	19.20	16.55	13.50	10.89	11.04
Close	22.30	26.49	17.90	14.74	11.90
Average daily volume (thousands)	706	656	420	430	305

- (1) Per unit amounts (with the exception of per unit distributions) are based on weighted average units plus units issuable for exchangeable shares.
- (2) Net income in the basic per trust unit calculation has been reduced by interest on the convertible debentures in 2003 and is based on net income after non-controlling interest divided by weighted average units (excluding units issuable for exchangeable shares) for the years 2003-2006.
- (3) Based on number of trust units outstanding at each cash distribution date.
- (4) Net debt excludes unrealized commodity and foreign exchange contracts asset and liability.
- (5) Includes trust units issuable for outstanding exchangeable shares based on the period end exchange ratio.
- (6) Represents total consideration for the corporate acquisition including fees but prior to working capital, asset retirement obligation and future income tax liability assumed on acquisition.
- (7) Established reserves for 2002.

QUARTERLY HISTORICAL REVIEW

(CDN \$ millions, except per unit amounts)	2006				2005			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
FINANCIAL								
Revenue before royalties	292.5	312.3	306.7	318.9	365.3	310.2	251.6	238.1
Per unit ⁽¹⁾	1.42	1.52	1.51	1.58	1.89	1.62	1.32	1.26
Cash flow	174.4	200.3	194.7	191.2	207.6	168.1	121.8	142.0
Per unit – basic ⁽¹⁾	0.85	0.98	0.96	0.94	1.07	0.88	0.64	0.75
Per unit – diluted	0.84	0.97	0.95	0.94	1.07	0.87	0.63	0.74
Net income	56.6	116.9	182.5	104.1	130.4	114.6	73.2	38.6
Per unit – basic ⁽²⁾	0.28	0.58	0.91	0.52	0.68	0.61	0.39	0.21
Per unit – diluted	0.28	0.58	0.91	0.52	0.68	0.59	0.39	0.20
Cash distributions	122.3	121.4	120.6	119.9	115.7	92.6	84.5	83.9
Per unit ⁽³⁾	0.60	0.60	0.60	0.60	0.60	0.49	0.45	0.45
Total assets	3,479.0	3,335.8	3,277.8	3,279.7	3,251.2	2,483.5	2,427.5	2,303.9
Total liabilities	1,550.6	1,371.3	1,339.9	1,434.1	1,415.5	912.2	895.2	785.8
Net debt outstanding ⁽⁴⁾	739.1	579.7	567.4	598.9	578.1	357.6	366.2	254.3
Weighted average units ⁽⁵⁾	206.5	205.1	203.7	202.5	193.4	191.7	190.3	189.2
Units outstanding and issuable ⁽⁵⁾	207.2	205.7	204.4	203.1	202.0	192.1	191.3	189.6
CAPITAL EXPENDITURES								
Geological and geophysical	3.7	2.2	2.8	2.7	3.0	2.3	2.7	1.3
Land	11.8	1.4	14.3	4.9	5.5	2.0	0.8	0.8
Drilling and completions	79.1	76.2	29.8	55.4	60.3	63.6	32.7	35.2
Plant and facilities	26.5	24.6	10.9	15.6	17.0	14.8	8.7	14.5
Other capital	0.8	0.5	0.8	0.5	2.0	0.3	0.6	0.7
Total capital expenditures	121.9	104.9	58.6	79.1	87.8	83.0	45.5	52.5
Property acquisitions (dispositions) net	76.4	8.4	2.8	27.6	3.0	5.9	78.7	3.7
Corporate acquisitions ⁽⁶⁾	16.6	-	-	-	462.8	-	42.2	-
Total capital expenditures and net acquisitions	214.9	113.3	61.4	106.7	553.6	88.9	166.4	56.2
OPERATING								
Production								
Crude oil (bbl/d)	29,605	29,108	27,805	29,651	25,534	23,513	22,046	21,993
Natural gas (mmcf/d)	179.5	173.4	178.5	185.0	177.9	168.2	173.1	176.1
Natural gas liquids (bbl/d)	4,144	4,166	4,247	4,120	3,943	4,047	3,962	4,072
Total (boe per day 6:1)	63,663	62,178	61,803	64,600	59,120	55,592	54,860	55,410
Average prices								
Crude oil (\$/bbl)	58.26	71.84	71.86	59.53	62.12	69.37	58.37	53.63
Natural gas (\$/mcf)	6.99	6.10	6.35	8.40	12.05	9.08	7.42	7.20
Natural gas liquids (\$/bbl)	46.51	56.60	54.44	52.91	57.14	50.43	46.13	46.57
Oil equivalent (\$/boe)	49.94	54.59	54.54	54.86	67.16	60.66	50.40	47.74
TRUST UNIT TRADING (based on intra-day trading)								
Unit prices								
High	29.22	30.74	28.61	27.51	27.58	24.20	20.30	20.40
Low	19.20	25.25	24.35	25.09	20.45	19.94	16.88	16.55
Close	22.30	27.21	28.00	27.36	26.49	24.10	19.94	18.15
Average daily volume (thousands)	1,125	614	548	546	653	599	605	895

- (1) Per unit amounts (with the exception of per unit distributions) are based on weighted average units plus units issuable for exchangeable shares.
- (2) Net income per unit is based on net income after non-controlling interest divided by weighted average units (excluding units issuable for exchangeable shares).
- (3) Based on number of trust units outstanding at each cash distribution date.
- (4) Net debt excludes unrealized commodity and foreign exchange contracts asset and liability.
- (5) Includes trust units issuable for outstanding exchangeable shares based on the period end exchange ratio.
- (6) Represents total consideration for the corporate acquisition including fees but prior to working capital, asset retirement obligation and future income tax liability assumed on acquisition.

CONSOLIDATED BALANCE SHEETS

As at December 31 (unaudited)

(CDN\$ millions)	2006	2005
ASSETS		
Current assets		
Cash and cash equivalents	\$ 2.8	\$ -
Accounts receivable	129.8	123.0
Prepaid expenses	18.4	14.0
Commodity and foreign currency contracts (Note 11)	25.7	3.1
	176.7	140.1
Reclamation funds (Note 4)	30.9	23.5
Property, plant and equipment (Note 5)	3,093.8	2,930.0
Long-term investment (Note 6)	20.0	-
Goodwill	157.6	157.6
Total assets	\$ 3,479.0	\$ 3,251.2
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities (Note 7)	\$ 162.1	\$ 148.6
Cash distributions payable	40.9	39.8
Commodity and foreign currency contracts (Note 11)	34.4	7.2
	237.4	195.6
Long-term debt (Note 8)	687.1	526.6
Other long-term liabilities (Note 9)	14.6	12.4
Asset retirement obligations (Note 10)	177.3	165.1
Future income taxes (Note 13)	434.2	515.9
Total liabilities	1,550.6	1,415.6
COMMITMENTS AND CONTINGENCIES (Note 21)		
NON-CONTROLLING INTEREST		
Exchangeable shares (Note 14)	40.0	37.5
UNITHOLDERS' EQUITY		
Unitholders' capital (Note 15)	2,349.2	2,230.8
Contributed surplus (Note 18)	2.4	6.4
Deficit (Note 16)	(463.2)	(439.1)
Total unitholders' equity	1,888.4	1,798.1
Total liabilities and unitholders' equity	\$ 3,479.0	\$ 3,251.2

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF INCOME AND DEFICIT

For the three and twelve months ended December 31 (unaudited)

(\$CDN millions, except per unit amounts)	Three months ended December 31		Twelve months ended December 31	
	2006	2005	2006	2005
Revenues				
Oil, natural gas and natural gas liquids	\$ 292.5	\$ 365.3	\$ 1,230.5	\$ 1,165.2
Royalties	(51.5)	(73.5)	(222.3)	(235.3)
	241.0	291.8	1,008.2	929.9
Gain (loss) on commodity and foreign currency contracts (Note 11)				
Realized	9.8	(26.4)	29.3	(87.6)
Unrealized	3.9	28.1	(4.6)	-
	254.7	293.5	1,032.9	842.3
Expenses				
Transportation	3.8	3.5	14.5	14.3
Operating	53.5	38.9	195.4	142.2
General and administrative	10.1	15.4	47.1	42.8
Interest on long-term debt (Note 8)	8.7	6.0	31.8	16.9
Depletion, depreciation and accretion (Notes 5 and 10)	96.2	73.7	360.0	264.5
Loss (gain) on foreign exchange (Note 12)	21.2	1.4	4.2	(6.4)
	193.5	138.9	653.0	474.3
Income before taxes	61.2	154.6	379.9	368.0
Capital and other taxes	-	(2.3)	(0.3)	(3.9)
Future income tax (expense) recovery (Note 13)	(3.7)	(19.8)	87.1	(1.6)
Net income before non-controlling interest	57.5	132.5	466.7	362.5
Non-controlling interest (Note 14)	(0.9)	(2.0)	(6.6)	(5.6)
Net income	\$ 56.6	\$ 130.5	\$ 460.1	\$ 356.9
Deficit, beginning of period	\$ (397.5)	\$ (453.9)	\$ (439.1)	\$ (419.4)
Distributions paid or declared (Note 17)	(122.3)	(115.7)	(484.2)	(376.6)
Deficit, end of period (Note 16)	\$ (463.2)	\$ (439.1)	\$ (463.2)	\$ (439.1)
Net income per unit (Note 20)				
Basic	\$ 0.28	\$ 0.68	\$ 2.28	\$ 1.90
Diluted	\$ 0.27	\$ 0.67	\$ 2.27	\$ 1.88

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the three and twelve months ended December 31 (unaudited)

(\$CDN millions)	Three months ended December 31		Twelve months ended December 31	
	2006	2005	2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	\$ 56.6	\$ 130.5	\$ 460.1	\$ 356.9
Add items not involving cash:				
Non-controlling interest (Note 14)	0.9	2.0	6.6	5.6
Future income tax expense (recovery) (Note 13)	3.7	19.8	(87.1)	1.6
Depletion, depreciation and accretion (Notes 5 and 10)	96.2	73.7	360.0	264.5
Non-cash (gain) loss on commodity and foreign currency contracts (Note 11)	(3.9)	(28.1)	4.6	-
Non-cash loss (gain) on foreign exchange (Note 12)	21.0	1.5	4.5	(6.3)
Non-cash trust unit incentive compensation (Notes 18 and 19)	(0.1)	8.2	11.9	17.2
Expenditures on site restoration and reclamation (Note 10)	(4.0)	(1.8)	(10.6)	(4.9)
Change in non-cash working capital	(11.1)	41.5	(16.0)	(17.9)
	159.3	247.3	734.0	616.7
CASH FLOWS FROM FINANCING ACTIVITIES				
Issuance of long-term debt under revolving credit facilities, net	167.1	155.0	162.7	258.2
Issuance of senior secured notes	-	86.8	-	86.8
Repayment of senior secured notes	(6.8)	(32.5)	(6.8)	(32.5)
Issue of trust units	2.2	242.7	14.4	259.7
Trust unit issue costs	(0.2)	(12.2)	(0.2)	(12.2)
Cash distributions paid, net of distribution reinvestment (Note 17)	(95.7)	(92.7)	(389.6)	(318.3)
Payment of retention bonuses (Note 9)	-	-	(1.0)	(1.0)
Change in non-cash working capital	(2.7)	(2.0)	-	(0.2)
	63.9	345.1	(220.5)	240.5
CASH FLOWS FROM INVESTING ACTIVITIES				
Corporate acquisition, net of cash received (Note 3)	(16.6)	(462.8)	(16.6)	(505.0)
Acquisition of petroleum and natural gas properties	(76.6)	(3.1)	(117.4)	(93.8)
Proceeds on disposition of petroleum and natural gas properties	-	(17.5)	2.1	2.5
Capital expenditures	(121.8)	(77.3)	(362.7)	(257.9)
Long-term investment (Note 6)	-	-	(20.0)	-
Net reclamation fund contributions (Note 4)	(1.9)	(0.2)	(7.4)	(2.2)
Changes in non-cash working capital	(3.9)	(53.7)	11.3	(5.2)
	(220.8)	(597.1)	(510.7)	(861.6)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	2.4	(4.7)	2.8	(4.4)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	0.4	4.7	-	4.4
CASH AND CASH EQUIVALENTS, END OF PERIOD	\$ 2.8	\$ -	\$ 2.8	\$ -

See accompanying notes to consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2006 and 2005 (unaudited)

(all tabular amounts in CDN\$ millions, except per unit and volume amounts)

1. STRUCTURE OF THE TRUST

ARC Energy Trust (the "Trust") was formed on May 7, 1996 pursuant to a Trust indenture (the "Trust Indenture") that has been amended from time to time, most recently on May 15, 2006. Computershare Trust Company of Canada was appointed as Trustee under the Trust Indenture. The beneficiaries of the Trust are the holders of the trust units.

The Trust was created for the purposes of issuing trust units to the public and investing the funds so raised to purchase a royalty in the properties of ARC Resources Ltd. ("ARC Resources") and ARC Sask Energy Trust ("ARC Sask"). The Trust Indenture was amended on June 7, 1999 to convert the Trust from a closed-end to an open-ended investment Trust. The current business of the Trust includes the investment in all types of energy business-related assets including, but not limited to, petroleum and natural gas-related assets, gathering, processing and transportation assets. The operations of the Trust consist of the acquisition, development, exploitation and disposition of these assets and the distribution of the net cash proceeds from these activities to the unitholders.

2. SUMMARY OF ACCOUNTING POLICIES

The consolidated financial statements have been prepared by management following Canadian generally accepted accounting principles ("GAAP"). The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingencies at the date of the financial statements, and revenues and expenses during the reporting year. Actual results could differ from those estimated.

In particular, the amounts recorded for depletion, depreciation and accretion of the petroleum and natural gas properties and for asset retirement obligations are based on estimates of reserves and future costs. By their nature, these estimates, and those related to future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

Principles of Consolidation

The consolidated financial statements include the accounts of the Trust and its subsidiaries. Any reference to "the Trust" throughout these consolidated financial statements refers to the Trust and its subsidiaries. All inter-entity transactions have been eliminated.

Revenue Recognition

Revenue associated with the sale of crude oil, natural gas, and natural gas liquids (NGLs) owned by the Trust are recognized when title passes from the Trust to its customers.

Transportation

Costs paid by the Trust for the transportation of natural gas, crude oil and NGLs from the wellhead to the point of title transfer are recognized when the transportation is provided.

Joint Venture

The Trust conducts many of its oil and gas production activities through joint ventures and the financial statements reflect only the Trust's proportionate interest in such activities.

Depletion and Depreciation

Depletion of petroleum and natural gas properties and depreciation of production equipment are calculated on the unit-of-production basis based on:

- (a) total estimated proved reserves calculated in accordance with National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities;
- (b) total capitalized costs, excluding undeveloped lands, plus estimated future development costs of proved undeveloped reserves, including future estimated asset retirement costs; and
- (c) relative volumes of petroleum and natural gas reserves and production, before royalties, converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil.

Unit Based Compensation

The Trust established a Trust Unit Incentive Rights Plan (the “Rights Plan”) for employees, independent directors and long-term consultants who otherwise meet the definition of an employee of the Trust. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. The Trust accounts for the rights using the fair value method, whereby the fair value of rights is determined on the date on which fair value can initially be determined. The fair value is then recorded as compensation expense over the period that the rights vest, with a corresponding increase to contributed surplus. When rights are exercised, the proceeds, together with the amount recorded in contributed surplus, are recorded to unitholders’ capital.

Whole Trust Unit Incentive Plan Compensation

The Trust has established a Whole Trust Unit Incentive Plan (the “Whole Unit Plan”) for employees, independent directors and long-term consultants who otherwise meet the definition of an employee of the Trust. Compensation expense associated with the Whole Unit Plan is granted in the form of Restricted Trust Units (“RTUs”) and Performance Trust Units (“PTUs”) and is determined based on the intrinsic value of the Whole Trust Units at each period end. The intrinsic valuation method is used as participants of the Whole Unit Plan receive a cash payment on a fixed vesting date. This valuation incorporates the period end Trust unit price, the number of RTUs and PTUs outstanding at each period end, and certain management estimates. As a result, large fluctuations, even recoveries, in compensation expense may occur due to changes in the underlying Trust unit price. In addition, compensation expense is amortized and recognized in earnings over the vesting period of the Whole Unit Plan with a corresponding increase or decrease in liabilities. Classification between accrued liabilities and other long-term liabilities is dependent on the expected payout date.

The Trust charges amounts relating to head office employees to general and administrative expense, amounts relating to field employees to operating expense and amounts relating to geologists and geophysicists to property, plant and equipment.

The Trust has not incorporated an estimated forfeiture rate for RTUs and PTUs that will not vest. Rather, the Trust accounts for actual forfeitures as they occur.

Cash and Cash Equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with an original maturity of three months or less when purchased.

Reclamation Funds

Reclamation funds hold investment grade assets which are carried at cost and are subject to impairment in the event of a non-temporary decline in market value.

Long-Term Investment

Investments are recorded and carried at cost and are subject to impairment in the event of a non-temporary decline in market value.

Property, Plant and Equipment (“PP&E”)

The Trust follows the full cost method of accounting. All costs of exploring, developing and acquiring petroleum and natural gas properties, including asset retirement costs, are capitalized and accumulated in one cost centre as all operations are in Canada. Maintenance and repairs are charged against income, and renewals and enhancements that extend the economic life of the PP&E are capitalized. Gains and losses are not recognized upon disposition of petroleum and natural gas properties unless such a disposition would alter the rate of depletion by 20 per cent or more.

Impairment

The Trust places a limit on the aggregate carrying value of PP&E, which may be amortized against revenues of future periods.

Impairment is recognized if the carrying amount of the PP&E exceeds the sum of the undiscounted cash flows expected to result from the Trust’s proved reserves. Cash flows are calculated based on third party quoted forward prices, adjusted for the Trust’s contract prices and quality differentials.

Upon recognition of impairment, the Trust would then measure the amount of impairment by comparing the carrying amounts of the PP&E to an amount equal to the estimated net present value of future cash flows from proved plus risked probable reserves. The Trust’s risk-free interest rate is used to arrive at the net present value of the future cash flows. Any excess carrying value above the net present value of the Trust’s future cash flows would be recorded as a permanent impairment and charged against net income.

The cost of unproved properties is excluded from the impairment test described above and subject to a separate impairment test. In the case of impairment, the book value of the impaired properties are moved to the petroleum and natural gas depletable base.

Goodwill

The Trust must record goodwill relating to a corporate acquisition when the total purchase price exceeds the fair value for accounting purposes of the net identifiable assets and liabilities of the acquired company. The goodwill balance is assessed for impairment annually at year-end or as events occur that could result in an impairment. Impairment is recognized based on the fair value of the reporting entity (consolidated Trust) compared to the book value of the reporting entity. If the fair value of the consolidated Trust is less than the book value, impairment is measured by allocating the fair value of the consolidated Trust to the identifiable assets and liabilities as if the Trust had been acquired in a business combination for a purchase price equal to its fair value. The excess of the fair value of the consolidated trust over the amounts assigned to the identifiable assets and liabilities is the fair value of the goodwill. Any excess of the book value of goodwill over this implied fair value of goodwill is the impairment amount. Impairment is charged to earnings in the period in which it occurs.

Goodwill is stated at cost less impairment and is not amortized.

Asset Retirement Obligations

The Trust recognizes the fair value of an Asset Retirement Obligation (“ARO”) in the period in which it is incurred when a reasonable estimate of the fair value can be made. On a periodic basis, management will review these estimates and changes, if any, to the estimate will be applied on a prospective basis. The fair value of the estimated ARO is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a unit-of-production basis over the life of the reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would also result in an increase or decrease to the ARO. Actual costs incurred upon settlement of the ARO are charged against the ARO to the extent of the liability recorded. Any difference between the actual costs incurred upon settlement of the ARO and the recorded liability is recognized as a gain or loss in the Trust’s earnings in the period in which the settlement occurs.

Income Taxes

The Trust follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements of the Trust’s corporate subsidiaries and their respective tax base, using substantively enacted future income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs. Temporary differences arising on acquisitions result in future income tax assets and liabilities.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. As the Trust distributes all of its taxable income to the unitholders and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for income taxes has been made in the Trust.

Basic and Diluted per Trust Unit Calculations

Basic net income per unit is computed by dividing the net income by the weighted average number of trust units outstanding during the period. Diluted net income per unit amounts are calculated based on net income before non-controlling interest divided by dilutive trust units. Dilutive trust units are arrived at by taking weighted average trust units and trust units issuable on conversion of exchangeable shares, and giving effect to the potential dilution that would occur if rights were exercised at the beginning of the period. The treasury stock method assumes that proceeds received from the exercise of in-the-money rights and any unrecognized trust unit incentive compensation are used to repurchase units at the average market price.

Derivative Financial Instruments

The Trust is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by the Trust to reduce its exposure to fluctuations in commodity prices, foreign exchange rates, and interest rates. The fair values of these derivative instruments are based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity. The Trust considers all of these transactions to be effective economic hedges, however, the majority of the Trust’s contracts do not qualify or have not been designated as effective hedges for accounting purposes.

For derivative instruments that do qualify as effective accounting hedges, policies and procedures are in place to ensure that the required documentation and approvals are in place. This documentation specifically ties the derivative financial instrument to their use, and in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated. When applicable, the Trust also identifies all relationships between hedging instruments and hedged items, as well as its risk management objective and the strategy for undertaking hedge transactions. This would include linking the particular derivative to specific assets and liabilities on the consolidated balance sheet or to specific firm commitments or forecasted transactions. Where specific hedges are executed, the Trust assesses, both at the inception of the hedge and on an ongoing basis, whether the derivative used in the particular hedging transaction is effective in offsetting changes in fair value or cash flows of the hedged item.

Realized and unrealized gains and losses associated with hedging instruments that have been terminated or cease to be effective prior to maturity, are deferred on the consolidated balance sheet and recognized in income in the period in which the underlying hedged transaction is recognized.

For transactions that do not qualify for hedge accounting, the Trust applies the fair value method of accounting by recording an asset or liability on the consolidated balance sheet and recognizing changes in the fair value of the instruments in the statement of income for the current period.

Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at the consolidated balance sheet date. Revenues and expenses are translated at the period average rates of exchange. Translation gains and losses are included in income in the period in which they arise.

Non-Controlling Interest

The Trust must record non-controlling interest when exchangeable shares issued by a subsidiary of the Trust are transferable to third parties. Non-controlling interest on the consolidated balance sheet is recognized based on the fair value of the exchangeable shares upon issuance plus the accumulated earnings attributable to the non-controlling interest. Net income is reduced for the portion of earnings attributable to the non-controlling interest. As the exchangeable shares are converted to trust units, the non-controlling interest on the consolidated balance sheet is reduced by the cumulative book value of the exchangeable shares and Unitholders' capital is increased by the corresponding amount.

3. CORPORATE ACQUISITIONS

On December 6, 2006 the Trust completed a minor corporate acquisition for net cash consideration of \$16.6 million. There was no goodwill recognized with this acquisition. Substantially all of the consideration was applied against property, plant and equipment, with a nominal amount applied against working capital items.

The following acquisitions were completed in 2005:

REDWATER AND NORTH PEMBINA CARDIUM UNIT

On December 16, 2005, the Trust acquired all of the issued and outstanding shares of three legal entities, 3115151 Nova Scotia Company, 3115152 Nova Scotia Company and 3115153 Nova Scotia Company which together hold the Redwater and North Pembina Cardium Unit assets (collectively "Redwater and NPCU") for total consideration of \$462.8 million. The allocation of the purchase price and consideration paid were as follows:

Net Assets Acquired

Working capital deficit	\$	(0.6)
Property, plant and equipment		729.5
Asset retirement obligations		(70.7)
Future income taxes		(195.4)
Total net assets acquired	\$	462.8

Consideration Paid

Cash consideration and fees paid	\$	462.8
Total consideration paid	\$	462.8

The acquisition of Redwater and NPCU has been accounted for as an asset acquisition pursuant to both management's view of the transaction and EIC-124.

In addition to consideration paid, the Trust committed to making contributions to a restricted reclamation fund as detailed in Note 21.

The future income tax liability on acquisition was based on the difference between the fair value of the acquired net assets of \$463.4 million and the associated tax basis of \$93.3 million.

These consolidated financial statements incorporate the operations of Redwater and NPCU from December 16, 2005.

ROMULUS EXPLORATION INC.

On June 30, 2005, the Trust acquired all of the issued and outstanding shares of Romulus Exploration Inc. ("Romulus") for total consideration of \$42.2 million. The allocation of the purchase price and consideration paid were as follows:

Net Assets Acquired	
Working capital deficit	\$ (1.4)
Property, plant and equipment	62.5
Asset retirement obligations	(0.4)
Future income taxes	(18.5)
Total net assets acquired	\$ 42.2

Consideration Paid	
Cash and fees paid	\$ 42.2
Total consideration paid	\$ 42.2

The acquisition of Romulus has been accounted for as an asset acquisition pursuant to both management's view of the transaction and EIC-124.

The future income tax liability on acquisition was based on the difference between the fair value of the acquired net assets of \$44 million and the associated tax basis of \$9 million.

These consolidated financial statements incorporate the operations of Romulus from June 30, 2005.

4. RECLAMATION FUNDS

	2006		2005	
	Unrestricted	Restricted	Unrestricted	Restricted
Balance, beginning of year	\$ 23.5	\$ -	\$ 21.3	\$ -
Contributions	6.0	6.1	6.0	-
Reimbursed expenditures ⁽¹⁾	(5.7)	-	(4.6)	-
Interest earned on funds	1.0	-	0.8	-
Balance, end of year	\$ 24.8	\$ 6.1	\$ 23.5	\$ -

⁽¹⁾ Amount differs from actual expenditures incurred by the Trust due to timing differences and discretionary reimbursements.

An unrestricted reclamation fund was established to fund future asset retirement obligation costs. In addition, the Trust has created a restricted reclamation fund associated with the Redwater property acquired in 2005. Contributions to the restricted and unrestricted reclamation funds and interest earned on the balances have been deducted from the cash distributions to the unitholders. The Board of Directors of ARC Resources has approved voluntary contributions to the unrestricted reclamation fund over a 20-year period that currently results in minimum annual contributions of \$6 million (\$6 million in 2005) based upon properties owned as at December 31, 2006. Contributions to the restricted reclamation fund will vary over time and have been disclosed in Note 21. Contributions for both funds are continually reassessed to ensure that the funds are sufficient to finance the majority of future abandonment obligations. Interest earned on the funds are retained within the funds.

5. PROPERTY, PLANT AND EQUIPMENT

	2006	2005
Property, plant and equipment, at cost	\$ 4,655.3	\$ 4,142.0
Accumulated depletion and depreciation	(1,561.5)	(1,212.0)
Property, plant and equipment, net	\$ 3,093.8	\$ 2,930.0

The calculation of 2006 depletion and depreciation included an estimated \$547 million (\$488 million in 2005) for future development costs associated with proved undeveloped reserves and excluded \$108.9 million (\$58.9 million in 2005) for the book value of unproved properties.

The Trust performed a ceiling test calculation at December 31, 2006 to assess the recoverable value of property plant and equipment (PP&E). Based on the calculation, the present value of future net revenues from the Trust's proved plus probable reserves exceeded the carrying value of the Trust's PP&E at December 31, 2006. The benchmark prices used in the calculation were as follows:

Year	WTI Oil (\$US/bbl)	AECO Gas (CDN\$/mmbtu)	USD/CAD Exchange Rates
2007	62.00	7.20	0.87
2008	60.00	7.45	0.87
2009	58.00	7.75	0.87
2010	57.00	7.80	0.87
2011	57.00	7.85	0.87
2012	57.50	8.15	0.87
2013	58.50	8.30	0.87
2014	59.75	8.50	0.87
2015	61.00	8.70	0.87
2016	62.25	8.90	0.87
2017	63.50	9.10	0.87
Remainder ⁽¹⁾	2.0%	2.0%	0.87

⁽¹⁾ Percentage change represents the change in each year after 2017 to the end of the reserve life.

6. LONG-TERM INVESTMENT

During the year the Trust entered into an equity investment in a private oil sands company in the amount of \$20 million. The investment in the shares of the private company has been considered to be a related party transaction due to common directorships of the Trust, the private company and the manager of a private equity fund that holds shares in the private company. The \$20 million investment was part of a \$325 million private placement of the private company. In addition, certain directors and officers of the Trust have minor direct and indirect shareholdings in the private company.

7. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2006	2005
Trades payable	\$ 39.0	\$ 33.0
Accrued liabilities	108.8	109.2
Current portion of accrued long-term incentive compensation	11.5	3.6
Interest payable	1.8	1.8
Retention bonuses	1.0	1.0
Total accounts payable and accrued liabilities	\$ 162.1	\$ 148.6

The current portion of accrued long-term incentive compensation represents the current portion of the Trust's estimated liability for the Whole Unit Plan as at December 31, 2006 (see Note 19). This amount is payable in 2007.

8. LONG-TERM DEBT

	2006	2005
Revolving credit facilities		
Syndicated credit facility	\$ 425.0	\$ 254.6
Working capital facility	1.1	3.8
Senior secured notes		
5.42% USD Note	87.4	87.4
4.94% USD Note	28.0	35.0
4.62% USD Note	72.8	72.9
5.10% USD Note	72.8	72.9
Total long-term debt outstanding	\$ 687.1	\$ 526.6

Revolving Credit Facilities

During 2006, the Trust entered into a \$572 million secured, annually extendible, financial covenant-based three year syndicated credit facility that expires in March 2009 and a \$25 million demand working capital facility. The revolving credit facility is extendible annually, security is in the form of floating charges on all lands and assignments and negative pledges on specific petroleum and natural gas properties.

Borrowings under the facility bear interest at bank prime (6.0 per cent and 5.0 per cent at December 31, 2006 and December 31, 2005, respectively) or, at the Trust's option, Canadian or U.S. dollar bankers' acceptances plus a stamping fee. The lenders review the credit facility each year and determine whether they will extend the revolving periods for another year. In the event that the credit facility is not extended at anytime before the maturity date, the loan balance will become repayable on the maturity date. The maturity date of the current credit facility is March 24, 2009.

The working capital facility allows for maximum borrowings of \$25 million and is due and payable immediately upon demand by the bank. The facility is secured and is subject to the same covenants as the syndicated credit facility.

Various borrowing options exist under the revolving credit facility including prime rate advances, bankers' acceptances and LIBOR based loans denominated in either Canadian or U.S. dollars. All drawings under the facility are subject to stamping fees that vary between 65 bps and 115 bps depending on certain consolidated financial ratios.

5.42 Per Cent and 4.94 Per Cent Senior Secured USD Notes

These senior secured notes were issued in two separate issues pursuant to an Uncommitted Master Shelf Agreement. The US\$24 million Senior secured notes were issued in 2002, bear interest at 4.94 per cent, have a remaining final term of 3.8 years (remaining average term of 2.3 years) and require equal principal payments of US\$6 million over a four year period commencing in 2007. The US\$75 million Senior secured notes were issued in 2005, bear interest at 5.42 per cent, have a remaining final term of 11 years (remaining weighted average term of 7.6 years) and require equal principal repayments over an eight year period commencing in 2010.

4.62 Per Cent and 5.10 Per Cent Senior Secured USD Notes

These notes were issued on April 27, 2004 via a private placement in two tranches of US\$62.5 million each. The first tranche of US\$62.5 million bears interest at 4.62 per cent and has a remaining final term of 7.3 years (remaining weighted average term of 4.9 years) and require equal principal repayments over a 6 year period commencing 2009. Immediately following the issuance, the Trust entered into interest rate swap contracts which effectively changed the interest rate from fixed to floating (see Note 11). The second tranche of US\$62.5 million bears interest at 5.10 per cent and has a remaining final term of 9.3 years (remaining weighted average term of 7.4 years). Repayments of the notes will occur over a five year period commencing in 2012.

Debt Covenants

The following are the significant financial covenants governing the revolving credit facilities:

- Long-term debt and letters of credit not to exceed three times annualized net income before non-cash items and interest expense;
- Long-term debt, letters of credit, and subordinated debt not to exceed four times annualized net income before non-cash items and interest expense; and
- Long-term debt and letters of credit not to exceed 50 per cent of unitholders' equity and long-term debt, letters of credit, and subordinated debt.

In the event that the Trust enters into a material acquisition whereby the purchase price exceeds 10 per cent of the book value of the Trust's assets, the ratios in the first two covenants above are increased to 3.5 and 5.5 times, respectively. As at December 31, 2006, the Trust had \$4.7 million in letters of credit (\$4.4 million in 2005), no subordinated debt, and was in compliance with all covenants.

The payment of principal and interest are allowable deductions in the calculation of cash available for distribution to unitholders and rank ahead of cash distributions payable to unitholders. Should the properties securing this debt generate insufficient revenue to repay the outstanding balances, the unitholders have no direct liability.

During 2006, the weighted-average effective interest rate under the credit facility was 5.3 per cent (3.3 per cent in 2005).

Amounts due under the working capital facility and the senior secured notes in the next 12 months have not been included in current liabilities as management has the ability and intent to refinance this amount through the syndicated credit facility.

Interest paid during the period did not differ significantly from interest expense.

9. OTHER LONG-TERM LIABILITIES

	2006		2005
Accrued long-term incentive compensation	\$ 14.6	\$	11.4
Retention bonuses	-		1.0
Total other long-term liabilities	\$ 14.6	\$	12.4

The accrued long-term incentive compensation represents the long-term portion of the Trust's estimated liability for the Whole Unit Plan as at December 31, 2006 (see Note 19). This amount is payable in 2008 through 2009.

The retention bonuses arose upon internalization of the management contract in 2002. The final retention payment will occur in August 2007 and therefore is classified as a current liability as at December 31, 2006.

10. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligations were estimated by management based on the Trust's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Trust has estimated the net present value of its total asset retirement obligations to be \$177.3 million as at December 31, 2006 (\$165.1 million in 2005) based on a total future undiscounted liability of \$1,042.6 million (\$603.4 million in 2005). These payments are expected to be made over the next 61 years with the bulk of payments being made in years 2017 to 2021 and 2057 to 2067. The Trust's weighted average credit adjusted risk free rate of 6.5 per cent (5.6 per cent in 2005) and an inflation rate of 2.0 per cent (2.0 per cent in 2005) were used to calculate the present value of the asset retirement obligations. During the year, no gains or losses were recognized on settlements of asset retirement obligations.

The following table reconciles the Trust's asset retirement obligations:

	2006		2005
Balance, beginning of year	\$ 165.1	\$	73.0
Increase in liabilities relating to corporate acquisitions	4.9		71.1
Increase in liabilities relating to development activities	2.8		5.1
Increase in liabilities relating to change in estimate	4.0		15.6
Settlement of liabilities during the year	(10.6)		(4.9)
Accretion expense	11.1		5.2
Balance, end of year	\$ 177.3	\$	165.1

11. FINANCIAL INSTRUMENTS

The Trust is exposed to a number of financial risks that are part of its normal course of business. The Trust has a risk management program in place that includes financial instruments as disclosed in this note. The objective of the risk management program is to mitigate the Trust's exposure to the following financial risks:

Credit Risk

Most of the Trust's accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. The Trust manages this credit risk by entering into sales contracts with only highly rated entities and reviewing its exposure to individual entities on a regular basis. With respect to counterparties to financial instruments the Trust partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

Volatility of Oil and Natural Gas Prices

The Trust's operational results and financial condition, and therefore the amount of distributions paid to unitholders are dependent on the prices received for oil and natural gas production. Oil and 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 Trust's financial condition and therefore on the distributions to unitholders. ARC may manage the risk associated with changes in commodity prices by entering into oil or natural gas price derivative contracts. To the extent that ARC engages in risk management activities related to commodity prices, it will be subject to credit risks associated with counterparties with which it contracts.

Variations in Interest Rates and Foreign Exchange Rates

Increases in interest rates could result in a significant increase in the amount the Trust pays to service variable interest debt, resulting in a decrease in distributions to unitholders. World oil prices are quoted in U.S. dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate that may fluctuate over time. Variations in the exchange rate of the Canadian dollar could have significant positive or negative impact on future distributions. ARC has initiated certain derivative contracts to attempt to mitigate these risks. To the extent that ARC engages in risk management activities related to foreign exchange rates, it will be subject to credit risk associated with counterparties with which it contracts. The increase in the exchange rate for the Canadian dollar and future Canadian/U.S. exchange rates will impact future distributions and the future value of the Trust's reserves as determined by independent evaluators.

Financial Instruments

Financial instruments of the Trust carried on the consolidated balance sheet consist mainly of cash and cash equivalents, accounts receivable, reclamation funds, current liabilities, other long-term liabilities, commodity and foreign currency contracts and long-term debt. Except as noted below, as at December 31, 2006 and 2005, there were no significant differences between the carrying value of these financial instruments and their estimated fair value due to their short-term nature.

The fair value of the US\$224 million fixed rate Senior secured notes approximated CDN\$257 million as at December 31, 2006 and will vary with changes in interest rates (2005 – US\$230 million outstanding approximated CDN\$269 million).

Derivative Contracts

Following is a summary of all derivative contracts in place as at December 31, 2006 in order to mitigate the risks discussed above:

Financial WTI Crude Oil Contracts

Term	Contract	Volume bbl/d	Bought Put US\$/bbl	Sold Put US\$/bbl	Sold Call US\$/bbl
Jan 07 – Feb 07	Bought Put	1,000	62.50	-	-
Jan 07 – Jun 07	Put Spread	1,000	75.00	62.70	-
Jan 07 – Jun 07	Put Spread	1,000	75.00	65.00	-
Jan 07 – Dec 07	Put Spread	1,000	75.00	60.00	-
Jan 07 – Dec 07	3 - Way Collar	2,500	65.00	52.50	80.00
Jan 07 – Dec 07	Put Spread	2,500	65.00	52.50	-
Jan 07 – Dec 09	3 - Way Collar	5,000	55.00	40.00	90.00
Jul 07 – Dec 07	Put Spread	1,000	65.00	55.00	-

Financial AECO Natural Gas Contracts

Term	Contract	Volume GJ/d	Bought Put CDN\$/GJ	Sold Put CDN\$/GJ	Sold Call CDN\$/GJ
Jan 07 – Mar 07	Collar	10,000	7.25	-	9.00
Jan 07 – Mar 07	Collar	10,000	7.50	-	9.50
Jan 07 – Mar 07	Collar	10,000	8.00	-	12.00
Jan 07 – Mar 07	Collar	20,000	8.50	-	12.35
Jan 07 – Mar 07	3 - Way Collar	10,000	8.00	5.50	11.90
Apr 07 – Oct 07	3 - Way Collar	10,000	7.25	5.25	9.00
Apr 07 – Oct 07	3 - Way Collar	10,000	7.50	5.50	9.50
Apr 07 – Oct 07	3 - Way Collar	30,000	7.00	5.00	8.65

Financial NYMEX Natural Gas Contracts

Term	Contract	Volume mmbtu/d	Bought Put US\$/mmbtu	Sold Put US\$/mmbtu	Sold Call US\$/mmbtu
Jan 07 – Mar 07	Collar	5,000	8.50	-	10.25
Jan 07 – Mar 07	Collar	10,000	8.25	-	10.00
Jan 07 – Mar 07	Collar	10,000	10.00	-	13.65

Financial Natural Gas AECO (monthly) to NYMEX (last 3 day) Basis Contracts

Term	Contract	Volume mmbtu/d	Basis Swap US\$/mmbtu
Jan 07 – Mar 07	Swap	40,000	(1.3125)
Apr 07 – Oct 08	Swap	50,000	(1.1160)
Nov 08 – Oct 10	Swap	50,000	(1.0430)

Financial Foreign Exchange Contracts ⁽¹⁾

Term	Contract	Volume MM US\$	Swap CDN\$/US\$	Swap US\$/CDN\$	Bought Put CDN\$/US\$	Sold Put CDN\$/US\$
USD Sales Contracts						
Jan 07 – Dec 07	Swap	192	1.1379	0.8788	-	-
USD Option Contracts						
Jan 07 – Dec 07	Put Spread	12	-	-	1.125	1.100
Jan 07 – Dec 07	Put Spread	12	-	-	1.128	1.098

⁽¹⁾ Contracted volume is a total notional volume for the entire term.

Financial Electricity Contracts ⁽²⁾

Term	Contract	Volume MWh	Swap CDN\$/MWh
Jan 07 – Dec 07	Swap	20.0	64.63
Jan 08 – Dec 08	Swap	15.0	60.17
Jan 09 – Dec 09	Swap	15.0	59.33
Jan 10 – Dec 10	Swap	5.0	63.00

⁽²⁾ Contracted volume is based on a 24/7 term.

Financial Interest Rate Contracts ⁽³⁾

Term	Contract	Principal MM USD	Fixed Annual Rate (%)	Spread on 3 Mo. LIBOR
Jan 07 – Apr 14	Swap	30.5	4.62	38.5 bps
Jan 07 – Apr 14	Swap	32.0	4.62	(25.5 bps)

⁽³⁾ Starting in 2009, the notional amount of the contracts decreases annually until 2014. The Trust pays the floating interest rate based on the three month LIBOR plus a spread and receives the fixed interest rate.

The Trust has designated its fixed price electricity and interest rate swap contracts as effective accounting hedges as at January 1, 2004. A realized gain of \$3.4 million (\$0.3 million gain in 2005) on the electricity contract has been included in operating costs. The fair value unrealized gain on the electricity contract of \$7 million has not been recorded on the consolidated balance sheet at December 31, 2006 (\$0.2 million loss in 2005). A realized loss of \$0.4 million for the year on the interest rate swap contracts has been included in interest expense (\$0.5 million gain in 2005). The fair value unrealized loss on the two interest rate swap contracts of \$1.8 million has not been recorded on the consolidated balance sheet at December 31, 2006 (\$1 million loss in 2005).

None of the Trust's commodity and foreign currency contracts have been designated as effective accounting hedges. Accordingly, all commodity and foreign currency contracts have been accounted as assets and liabilities in the consolidated balance sheet based on their fair values.

The following table reconciles the movement in the fair value of the Trust's financial commodity and foreign currency contracts that have not been designated as effective accounting hedges:

	2006		2005	
Fair value, beginning of year ⁽¹⁾	\$	(4.1)	\$	(4.1)
Fair value, end of year		(8.7)		(4.1)
Change in fair value of contracts in the year ⁽¹⁾		(4.6)		-
Realized gains (losses) in the year		29.3		(87.6)
Gain (loss) on commodity and foreign currency contracts ⁽¹⁾	\$	24.7	\$	(87.6)
Commodity and foreign currency contracts asset	\$	25.7	\$	3.1
Commodity and foreign currency contracts liability	\$	(34.4)	\$	(7.2)

⁽¹⁾ Excludes the fixed price electricity contract and interest rate swap contracts that were accounted for as effective accounting hedges.

The Trust recorded a net gain on commodity and foreign currency contracts of \$24.7 million in the statement of income for 2006 (\$87.6 million loss in 2005). This amount includes the realized and unrealized gains and losses on derivative contracts that do not qualify as effective accounting hedges. During the year, \$4.6 million in unrealized losses (\$ nil in 2005) and \$29.3 million in realized cash gains (\$87.6 million loss in 2005) on contracts was recognized during the year.

12. GAIN (LOSS) ON FOREIGN EXCHANGE

The following is a summary of the total gain (loss) US\$ denominated transactions:

	2006		2005	
Unrealized (loss) on US\$ denominated debt	\$	(7.1)	\$	(4.2)
Realized gain on US\$ denominated debt repayments		2.6		10.5
Total non-cash (loss) gain on US\$ denominated transactions		(4.5)		6.3
Realized cash gain on US\$ denominated transactions		0.3		0.1
Total foreign exchange (loss) gain	\$	(4.2)	\$	6.4

13. INCOME TAXES

The tax provision differs from the amount computed by applying the combined Canadian federal and provincial statutory income tax rates to income before future income tax recovery as follows:

	2006		2005
Income before future income tax expense and recovery	\$ 379.6	\$	364.1
Canadian statutory rate	34.5%		37.6%
Expected income tax expense at statutory rates	130.9		137.0
Effect on income tax of:			
Net income of the Trust	(138.0)		(111.7)
Effect of change in corporate tax rate	(62.2)		(4.9)
Resource allowance	(10.7)		(20.0)
Change in estimated pool balances	(10.0)		-
Unrealized loss (gain) on foreign exchange	1.2		(1.6)
Non-deductible crown charges	1.2		1.3
Other non-deductible items	0.5		1.5
Future income tax (recovery) expense	\$ (87.1)	\$	1.6

The net future income tax liability is comprised of the following:

	2006		2005
Future tax liabilities:			
Capital assets in excess of tax value	\$ 509.8	\$	569.8
Long-term debt	4.0		-
Future tax assets:			
Non-capital losses	(5.3)		(1.5)
Asset retirement obligations	(52.1)		(45.7)
Accrued long-term incentive compensation	(7.7)		-
Commodity and foreign currency contracts	(2.5)		(1.4)
Attributed Canadian royalty income	(10.4)		(5.3)
Cumulative eligible capital and deductible share issue costs	(1.6)		-
Net future income tax liability	\$ 434.2	\$	515.9

The petroleum and natural gas properties and facilities owned by the Trust's subsidiaries have an approximate tax basis of \$1,031 million (\$788.4 million in 2005) available for future use as deductions from taxable income. Included in this tax basis are estimated non-capital loss carry forwards of \$18.2 million (\$13.1 million in 2005) that expire in the years 2008 through 2026. The following is a summary of the estimated Trust's subsidiaries' tax basis:

	2006		2005
Canadian oil and gas property expenses	\$ 200.1	\$	88.6
Canadian development expenses	285.9		201.3
Canadian exploration expenses	27.7		22.7
Undepreciated capital cost	389.0		352.2
Non-capital losses	18.2		13.1
Provincial tax pools	104.5		104.5
Other	5.6		6.0
Estimated tax basis	\$ 1,031.0	\$	788.4

In addition to the above tax basis for the Trust's subsidiaries, the Trust itself has an approximate tax basis of \$545.1 million as at December 31, 2006 (\$555.4 million in 2005).

On October 31, 2006, the Federal Government announced a proposed Trust taxation pertaining to taxation of distributions paid by publicly traded income Trusts. Currently, distributions paid to unitholders, other than returns of capital, are claimed as a deduction by the Trust in arriving at taxable income whereby tax is eliminated at the Trust level and is paid by the unitholders. The proposals would result in a two-tiered tax structure whereby distributions would first be subject to a 31.5 per cent tax at the Trust level commencing in 2011 and then investors would be subject to tax on the distribution as if it were a taxable dividend paid by a taxable Canadian corporation. If enacted, the proposals would apply to the Trust effective January 1, 2011. The Trust is currently

assessing various alternatives with respect to the potential implications of the tax proposals; however, until the legislation is enacted in final form, the Trust will not arrive at a final conclusion with respect to future Trust structure and implications to the Trust. As the tax proposals had not yet been substantively enacted as of December 31, 2006, the consolidated financial statements do not reflect the impact of the proposed taxation.

No current income taxes were paid or payable in 2006.

14. EXCHANGEABLE SHARES

The ARC Resources exchangeable shares (“ARL Exchangeable Shares”) were issued on January 31, 2001 at \$11.36 per exchangeable share as partial consideration for the Startech Energy Inc. acquisition. The issue price of the exchangeable shares was determined based on the weighted average trading price of Trust units preceding the date of announcement of the acquisition. The ARL Exchangeable Shares had an exchange ratio of 1:1 at the time of issuance.

The Trust is authorized to issue an unlimited number of ARL Exchangeable Shares which can be converted (at the option of the holder) into Trust units at any time. The number of Trust units issuable upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is calculated monthly based on the cash distribution paid divided by the ten day weighted average unit price preceding the record date and multiplied by the opening exchange ratio. The exchangeable shares are not eligible for distributions and, in the event that they are not converted, any outstanding shares are redeemable by the Trust for Trust units on August 28, 2012. The ARL Exchangeable Shares are publicly traded.

ARL EXCHANGEABLE SHARES (thousands)	2006	2005
Balance, beginning of year	1,595	1,784
Exchanged for Trust units	(162)	(189)
Balance, end of year	1,433	1,595
Exchange ratio, end of year	2.01251	1.83996
Trust units issuable upon conversion, end of year	2,884	2,935

The non-controlling interest on the consolidated balance sheet consists of the fair value of the exchangeable shares upon issuance plus the accumulated earnings attributable to the non-controlling interest. The net income attributable to the non-controlling interest on the consolidated statement of income represents the cumulative share of net income attributable to the non-controlling interest based on the Trust units issuable for exchangeable shares in proportion to total Trust units issued and issuable at each period end.

Following is a summary of the non-controlling interest for 2006 and 2005:

	2006	2005
Non-controlling interest, beginning of year	\$ 37.5	\$ 35.9
Reduction of book value for conversion to Trust units	(4.1)	(4.0)
Current year net income attributable to non-controlling interest	6.6	5.6
Non-controlling interest, end of year	\$ 40.0	\$ 37.5
Accumulated earnings attributable to non-controlling interest	\$ 27.3	\$ 20.7

15. UNITHOLDERS' CAPITAL

The Trust is authorized to issue 650 million Trust units of which 204.3 million units were issued and outstanding as at December 31, 2006 (199.1 million as at December 31, 2005).

The Trust has in place a Distribution Reinvestment and Optional Cash Payment Program (“DRIP”) in conjunction with the Trusts’ transfer agent to provide the option for unitholders to reinvest cash distributions into additional Trust units issued from treasury at a five per cent discount to the prevailing market price with no additional fees or commissions.

The Trust is an open ended mutual fund under which unitholders have the right to request redemption directly from the Trust. Units tendered by holders are subject to redemption under certain terms and conditions including the determination of the redemption price at the lower of the closing market price on the date units are tendered or 90 per cent of the weighted average trading price for the 10 day trading period commencing on the tender date. Cash payments for units tendered for redemption are limited to \$100,000 per month with redemption

requests in excess of this amount eligible to receive a note from ARC Resources Ltd. accruing interest at 4.5 per cent and repayable within 20 years.

	2006		2005	
	Number of Trust Units (thousands)	\$	Number of Trust Units (thousands)	\$
Balance, beginning of year	199,104	2,230.8	185,822	1,926.4
Issued for cash	1	-	9,000	239.8
Issued on conversion of ARL exchangeable shares (Note 14)	310	4.1	333	4.0
Issued on exercise of employee rights (Note 18)	978	18.4	1,500	24.0
Distribution reinvestment program	3,896	96.1	2,449	48.8
Trust unit issue costs	-	(0.2)	-	(12.2)
Balance, end of year	204,289	2,349.2	199,104	2,230.8

16. DEFICIT

The deficit balance is composed of the following items:

	2006	2005
Accumulated earnings	\$ 1,695.8	\$ 1,235.7
Accumulated cash distributions	(2,159.0)	(1,674.8)
Deficit	\$ (463.2)	\$ (439.1)

During the year, presentation changes were made to combine the previously reported Accumulated Earnings and Accumulated Cash Distribution figures on the balance sheet into a single Deficit balance. The Trust has historically paid cash distributions in excess of accumulated earnings as cash distributions are based on cash flow generated in the current period while accumulated earnings are based on cash flow generated in the current period less a depletion, depreciation, and accretion expense recorded on the original property, plant, and equipment investment and other non-cash charges.

17. RECONCILIATION OF CASH FLOW AND DISTRIBUTIONS

Cash distributions are calculated in accordance with the Trust Indenture. To arrive at cash distributions, cash flow from operating activities adjusted for changes in non-cash working capital and expenditures on site restoration and reclamation, is reduced by reclamation funds contributions including interest earned on the fund and a portion of capital expenditures. The portion of cash flow withheld to fund capital expenditures is at the discretion of the Board of Directors.

	2006	2005
Cash flow from operating activities	\$ 734.0	\$ 616.7
Change in non-cash working capital	16.0	17.9
Expenditures on site reclamation and restoration	10.6	4.9
Cash flow from operating activities after the above adjustments	760.6	639.5
Deduct:		
Cash withheld to fund current period capital expenditures	(263.2)	(256.1)
Reclamation fund contributions and interest earned on fund balances	(13.2)	(6.8)
Cash distributions ⁽¹⁾	484.2	376.6
Accumulated cash distributions, beginning of year	1,674.8	1,298.2
Accumulated cash distributions, end of year	\$ 2,159.0	\$ 1,674.8
Cash distributions per unit ⁽²⁾	\$ 2.40	\$ 1.99
Accumulated cash distributions per unit, beginning of year	16.23	14.24
Accumulated cash distributions per unit, end of year	\$ 18.63	\$ 16.23

⁽¹⁾ Cash distributions include non-cash amounts of \$94.6 million (\$58.3 million in 2005). These amounts relate to the distribution reinvestment program.

⁽²⁾ Cash distributions per trust unit reflect the sum of the per trust unit amounts declared monthly to unitholders.

18. TRUST UNIT INCENTIVE RIGHTS PLAN

The Trust Unit Incentive Rights Plan (the “Rights Plan”) was established in 1999 and authorized the Trust to grant up to 8,000,000 rights to its employees, independent directors and long-term consultants to purchase Trust units, of which 7,866,088 were granted to December 31, 2006. The initial exercise price of rights granted under the Rights Plan could not be less than the market price of the trust units as at the date of grant and the maximum term of each right was not to exceed ten years. In general, the rights have a five year term and vest equally over three years commencing on the first anniversary date of the grant. In addition, the exercise price of the rights is to be adjusted downwards from time to time by the amount, if any, that distributions to unitholders in any calendar quarter exceeds 2.5 per cent (ten per cent annually) of the Trust’s net book value of property, plant and equipment (the “Excess Distribution”), as determined by the Trust.

During the 2006 and 2005, the Trust did not grant any rights as the Rights Plan was replaced with a Whole Unit Plan during 2004 (see Note 19). The existing Rights Plan will be in place until the remaining 0.4 million rights outstanding as at December 31, 2006 are exercised or cancelled.

A summary of the changes in rights outstanding under the Rights Plan is as follows:

	2006		2005	
	Number of Rights (thousands)	Weighted Average Exercise Price (\$)	Number of Rights (thousands)	Weighted Average Exercise Price (\$)
Balance, beginning of year	1,349	10.22	3,009	10.92
Granted	-	-	-	-
Exercised	(978)	12.19	(1,500)	11.60
Cancelled	(2)	10.07	(160)	10.99
Balance before reduction of exercise price	369	10.40	1,349	11.10
Reduction of exercise price ⁽¹⁾	-	(0.93)	-	(0.88)
Balance, end of year	369	9.47	1,349	10.22

⁽¹⁾ The holder of the right has the option to exercise rights held at the original grant price or a reduced exercise price.

A summary of the plan as at December 31, 2006 is as follows:

Exercise Price At Grant Date (\$)	Adjusted Exercise Price (\$)	Number of Rights Outstanding (thousands)	Remaining Contractual Life of Rights (years)	Number of Rights Exercisable (thousands)
12.58	9.11	32	0.4	32
12.29	9.40	328	1.4	328
15.42	13.27	9	2.2	3
12.40	9.47	369	1.3	363

The Trust recorded compensation expense of \$2.5 million for the year (\$6.5 million in 2005) for the cost associated with the rights. Of the 3,013,569 rights issued on or after January 1, 2003 that were subject to recording compensation expense, 357,999 rights have been cancelled and 2,318,222 rights have been exercised to December 31, 2006.

The Trust used the Black-Scholes option-pricing model to calculate the estimated fair value of the outstanding rights issued on or after January 1, 2003. Subsequent to the initial valuation, the Trust used a binomial lattice model and observed immaterial valuation differences. The following assumptions were used to arrive at the estimate of fair value as at December 31, 2004:

	2004
Expected annual right’s exercise price reduction	0.72
Expected volatility	13.2%
Risk-free interest rate	3.7%
Expected life of option (years)	1.1
Expected forfeitures	0%

Prior to 2004, the Trust recorded compensation expense on its Rights Plan using the intrinsic method. In 2004, the Trust adopted the fair value method. Use of the fair value prior to 2004 would have resulted in an immaterial impact to the Trust.

The following table reconciles the movement in the contributed surplus balance for 2006 and 2005:

	2006		2005	
Balance, beginning of year	\$	6.4	\$	6.5
Compensation expense		2.5		6.5
Net benefit on rights exercised ⁽¹⁾		(6.5)		(6.6)
Balance, end of year	\$	2.4	\$	6.4

⁽¹⁾ Upon exercise, the net benefit is reflected as a reduction of contributed surplus and an increase to unitholders' capital.

19. WHOLE TRUST UNIT INCENTIVE PLAN

In March 2004, the Board of Directors, upon recommendation of the Compensation Committee, approved a new Whole Trust Unit Incentive Plan (the "Whole Unit Plan") to replace the existing Trust Unit Incentive Rights Plan for new awards granted subsequent to March 31, 2004. The new Whole Unit Plan will result in employees, officers and directors (the "plan participants") receiving cash compensation in relation to the value of a specified number of underlying notional trust units. The Whole Unit Plan consists of Restricted Trust Units ("RTUs") for which the number of trust units is fixed and will vest over a period of three years and Performance Trust Units ("PTUs") for which the number of trust units is variable and will vest at the end of three years.

Upon vesting, the plan participant receives a cash payment based on the fair value of the underlying trust units plus notional accrued distributions. The cash compensation issued upon vesting of the PTUs is dependent upon the future performance of the Trust compared to its peers based on a performance multiplier. The performance multiplier is based on the percentile rank of the Trust's Total Unitholder Return. The cash compensation issued upon vesting of the PTUs may range from zero to two times the value of the PTUs originally granted.

The fair value associated with the RTUs and PTUs is expensed in the statement of income over the vesting period. As the value of the RTUs and PTUs is dependent upon the trust unit price, the expense recorded in the statement of income may fluctuate over time.

The Trust recorded compensation expense of \$8.2 million and \$1.1 million to general and administrative and operating expenses, respectively, and capitalized \$1.8 million to property, plant and equipment in the twelve months ended December 31, 2006 for the estimated cost of the plan (\$8.8 million, \$1.9 million, and \$1.4 million for the twelve months ended December 31, 2005). The compensation expense was based on the December 31, 2006 unit price of \$22.30 (\$26.49 in 2005), accrued distributions, a performance multiplier ranging from 1.9 to 2.0 for the various series (2.0 in 2005), and the number of units to be issued on maturity.

The following table summarizes the RTU and PTU movement for the twelve months ended December 31, 2006 and 2005:

	2006		2005	
	Number of RTUs (thousands)	Number of PTUs (thousands)	Number of RTUs (thousands)	Number of PTUs (thousands)
Balance, beginning of year	479	391	224	128
Vested	(180)	-	(78)	-
Granted	373	303	367	305
Forfeited	(24)	(11)	(34)	(42)
Balance, end of year	648	683	479	391

The following table reconciles the change in total accrued compensation liability relating to the Whole Unit Plan:

	2006	2005
Balance, beginning of year	\$ 15.0	\$ 2.9
Change in liabilities in the year		
General and administrative expense	8.2	8.8
Operating expense	1.1	1.9
Property, plant and equipment	1.8	1.4
Balance, end of year	\$ 26.1	\$ 15.0
Current portion of liability (Note 7)	11.5	3.6
Long-term liability	\$ 14.6	\$ 11.4

During the year \$5.2 million in cash payments were made to employees relating to the Whole Unit Plan (\$1.6 million in 2005).

20. BASIC AND DILUTED PER TRUST UNIT CALCULATIONS

Net income per Trust unit has been determined based on the following:

(thousands)	Three months ended December 31		Twelve months ended December 31	
	2006	2005	2006	2005
Weighted average trust units ⁽¹⁾	203,580	190,510	201,554	188,237
Trust units issuable on conversion of exchangeable shares ⁽²⁾	2,884	2,935	2,884	2,935
Dilutive impact of rights ⁽³⁾	323	925	711	1,372
Dilutive trust units and exchangeable shares	206,787	194,370	205,149	192,544

⁽¹⁾ Weighted average Trust units exclude trust units issuable for exchangeable shares.

⁽²⁾ Diluted trust units include trust units issuable for outstanding exchangeable shares at the period end exchange ratio.

⁽³⁾ All outstanding rights were dilutive and therefore have been included in the diluted unit calculation for both 2006 and 2005.

Basic net income per unit has been calculated based on net income after non-controlling interest divided by weighted average trust units. Diluted net income per unit has been calculated based on net income before non-controlling interest divided by dilutive trust units.

21. COMMITMENTS AND CONTINGENCIES

Following is a summary of the Trust's contractual obligations and commitments as at December 31, 2006:

	Payments Due By Period				
	2007	2008-2009	2010-2011	Thereafter	Total
Debt repayments ⁽¹⁾	8.0	451.2	53.1	174.8	687.1
Interest payments ⁽²⁾	11.3	21.5	18.1	20.8	71.7
Reclamation fund contributions ⁽³⁾	6.0	11.1	9.5	76.2	102.8
Purchase commitments	12.6	8.4	3.4	6.8	31.2
Operating leases	5.3	9.9	5.0	-	20.2
Derivative contract premiums ⁽⁴⁾	12.4	3.3	-	-	15.7
Retention bonuses	1.0	-	-	-	1.0
Total contractual obligations	56.6	505.4	89.1	278.6	929.7

⁽¹⁾ Long-term and short-term debt, excluding interest.

⁽²⁾ Fixed interest payments on Senior secured notes.

⁽³⁾ Contribution commitments to a restricted reclamation fund associated with the Redwater property acquired in 2005.

⁽⁴⁾ Fixed premiums to be paid in future periods on certain commodity derivative contracts.

The above noted derivative contract premiums are part of the Trust's commitments related to its risk management program. In addition to the above premiums, the Trust has commitments related to its risk management program (see Note 11). As the premiums are part of the underlying derivative contract, they have

been recorded at fair market value at December 31, 2006 on the balance sheet as part of commodity and foreign currency contracts.

The Trust enters into commitments for capital expenditures in advance of the expenditures being made. At a given point in time, it is estimated that the Trust has committed to capital expenditures equal to approximately one quarter of its capital budget by means of giving the necessary authorizations to incur the capital in a future period. The Trust's 2007 capital budget has been approved by the Board at \$360 million. This commitment has not been disclosed in the commitment table as it is of a routine nature and is part of normal course of operations for active oil and gas companies and trusts.

The Trust is involved in litigation and claims arising in the normal course of operations. Management is of the opinion that pending litigation will not have a material adverse impact on the Trust's financial position or results of operations and therefore the following table does not include any commitments for outstanding litigation and claims.

The Trust has certain sales contracts with aggregators whereby the price received by the Trust is dependent upon the contracts entered into by the aggregator. This commitment has not been disclosed in the commitment table as it is of a routine nature and is part of normal course of operations.

ARC Energy Trust is one of Canada's largest conventional oil and gas royalty trusts with an enterprise value of approximately \$5.4 billion. The Trust currently has an interest in oil and gas production of approximately 63,000 barrels of oil equivalent per day from six core areas in western Canada. The royalty trust structure allows net cash flow to be distributed to unitholders in a tax efficient manner. ARC Energy Trust trades on the TSX under the symbol AET.UN.

ADVISORY - In the interests of providing ARC unitholders and potential investors with information regarding ARC, including management's assessment of ARC's future plans and operations, certain information contained in this document are forward-looking statements within the meaning of the "safe harbour" provisions of the United States Private Securities Litigation Reform Act of 1995 and the Ontario Securities Commission. Forward-looking statements in this document include, but are not limited to, ARC's internal projections, expectations or beliefs concerning future operating results, and various components thereof; the production and growth potential of its various assets, estimated total production and production growth for 2007 and beyond; the sources, deployment and allocation of expected capital in 2007; and the success of future development drilling prospects. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause ARC's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements.

ARC RESOURCES LTD.

John P. Dielwart,
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