ARC ENERGY TRUST

Third Quarter Interim Report

For The Three Months Ended September 30, 2005

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	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	**2005**	2004
FINANCIAL				
($CDN thousands, except per unit and per boe amounts)				
Revenue before royalties	**310,249**	230,769	**799,899**	669,670
Per unit [8]	**1.62**	1.23	**4.20**	3.61
Per boe	**60.66**	44.72	**53.00**	42.80
Cash flow [3]	**168,117**	110,835	**431,891**	341,098
Per unit [8]	**0.88**	0.59	**2.27**	1.84
Per boe	**32.87**	21.48	**28.61**	21.80
Net income [5]	**114,600**	38,897	**226,461**	128,695
Per unit [1] [5]	**0.61**	0.21	**1.21**	0.71
Cash distributions	**92,559**	83,178	**260,895**	246,447
Per unit [1]	**0.49**	0.45	**1.39**	1.35
Payout ratio [6]	**55%**	75%	**60%**	72%
Net debt outstanding [4]	**357,560**	220,500	**357,560**	220,500
OPERATING				
Production				
Crude oil (bbl/d)	**23,513**	22,496	**22,523**	22,958
Natural gas (mcf/d)	**168,194**	177,396	**172,432**	179,529
Natural gas liquids (bbl/d)	**4,047**	4,034	**4,027**	4,223
Total (boe/d)	**55,592**	56,096	**55,288**	57,102
Average prices [5]				
Crude oil ($/bbl)	**69.37**	51.00	**60.72**	46.20
Natural gas ($/mcf)	**9.08**	6.65	**7.89**	6.77
Oil equivalent ($/boe) [7]	**60.66**	44.72	**52.99**	42.80
Operating netback ($/boe)				
Commodity and other revenue (before hedging)	**60.66**	44.72	**52.99**	42.80
Transportation costs	**(0.66)**	(0.69)	**(0.71)**	(0.70)
Royalties	**(12.77)**	(9.17)	**(10.72)**	(8.42)
Operating costs	**(7.07)**	(6.98)	**(6.84)**	(6.69)
Netback (before hedging)	**40.16**	27.88	**34.72**	26.99
TRUST UNITS				
(thousands)				
Units outstanding, end of period	**189,150**	185,231	**189,150**	185,231
Units issuable for exchangeable shares	**2,939**	2,954	**2,939**	2,954
Total units outstanding and issuable for exchangeable shares, end of period	**192,089**	188,185	**192,089**	188,185
Weighted average units [2]	**188,770**	184,675	**187,470**	182,311
TRUST UNIT TRADING STATISTICS				
($CDN, except volumes) based on intra-day trading				
High	**24.20**	17.38	**24.20**	17.38
Low	**19.94**	15.02	**16.55**	13.50
Close	**24.10**	16.85	**24.10**	16.85
Average daily volume	**598,962**	383,522	**656,410**	408,351

(1) Per unit amounts (with the exception of per unit distributions) are based on weighted average units.
(2) Excludes trust units issuable for outstanding exchangeable shares at period end.
(3) 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 before changes in non-cash working capital and expenditures on site restoration and reclamation.
(4) Net debt excludes unrealized commodity and foreign exchange contracts.
(5) Net income and net income per unit for 2004 have been restated for the adoption of the new accounting standard for non-controlling interest in the fourth quarter of 2004. See Note 2 of the unaudited interim consolidated financial statements for details of the restatement.
(6) Cash distributions divided by cash flow from operations.
(7) Includes other revenue.
(8) Per unit amounts are based on weighted average units plus units issuable for exchangeable shares at period end.

MESSAGE TO UNITHOLDERS

Another quarter of increasing commodity prices has continued to benefit ARC and its unitholders with West Texas Intermediate crude oil averaging US$63.16 per barrel and AECO natural gas averaging CDN$8.00 per mcf. As a result, ARC once again achieved record revenues and cash flow. With both oil and natural gas production substantially curtailed due to hurricane damage in the Gulf of Mexico, the forward market prices are the highest we have ever seen, which has allowed us to increase distributions 33 per cent from $0.15 per unit in August to $0.20 per unit commencing with the November 15 distribution. It is ARC's view that this increased distribution level is sustainable at the prevailing commodity prices.

ARC continued to focus on its internal development program, spending $83.1 million during the third quarter on drilling and exploitation activities. Once again, ARC funded its capital program through cash flow withheld from distributions and proceeds from the distribution reinvestment plan. In spite of extremely wet weather in certain areas, ARC drilled 167 wells during the third quarter, resulting in 1,800 boe/d awaiting tie-in at the end of the quarter. With the exception of some very minor transactions for additional interests in existing assets, ARC did not complete any acquisitions in the third quarter.

ARC has ongoing development projects in all of our core areas. Our 2005 shallow gas drilling program was substantially completed in the third quarter including 90 wells in the Brooks / Jenner area of SE Alberta and 70 wells in the Hatton area of SW Saskatchewan. Despite significant delays due to wet weather, all of the wells are expected to be completed by year-end. The Pembina area, which has been on production for over 50 years, continues to exhibit stable production as a result of shallow decline and numerous infill drilling opportunities. Though operating costs are high due to low average per well productivity, the high quality of the oil (38 degrees API) and low royalty rates delivered an average netback of $40.67 per boe in the third quarter. In Ante Creek, ARC is executing a $30 million capital program in 2005 and has recently contracted a rig to drill year-round as we infill drill in the wake of successfully extending the pool boundaries to the south and east. We expect to drill 12 to 15 wells per year over the next three to four years in this area.

ARC is using new technology to increase recovery factors in its tight gas area of Dawson. A horizontal well drilled in the first quarter was successfully completed in July using a new fracturing technique not previously employed in western Canada. The process utilized a series of five 120 tonne fracs spaced equally along the length of the horizontal leg to effectively open more of the reservoir to contribute to the well's productivity. Although it is still in the early stages of production, the well is performing at better than forecast rates. At $6 million, the well was expensive to drill and complete; however, if the positive production results continue, future development of the field using horizontal wells will substantially reduce future capital costs and potentially expose more of the reservoir to commercial recovery increasing the ultimate reserves for the field.

Recently, the federal government has indicated that it is studying the income fund sector and is concerned about what it sees as significant tax loss as a result of corporations converting to the income fund structure. The government also expressed concern that a slow down of economic activity and reduced productivity could result when corporations convert to a structure focused on maintaining stable distributions. The government has put out a consultation paper on the topic and has invited interested parties to submit comments.

The possibility that the government may impose additional taxes or restrictions on income trusts has created considerable uncertainty in the market which has resulted in increased volatility in the price of our units with large daily fluctuations in the unit price becoming the norm. The imposition of new taxes on income trusts would likely lead to a reduction in distributions and hence a further reduction in unit values.

ARC would encourage any of its unitholders who feel strongly on this issue to participate in the process so that their voices can be heard.

For written submission, send an e-mail to:	trusts-fiducies@fin.gc.ca
To contact the Minister of Finance:	The Honourable Ralph Goodale Department of Finance 140 O'Connor Street Ottawa, Ontario K1A 0A6 Phone: 613 996-4743 Fax: 613 996-9790 e-mail: goodale.R@parl.gc.ca
To contact your Member of Parliament:	www.canada.gc.ca/directories/direct_ee.html

ARC Energy Trust has been functioning under the current tax rules as a publicly traded Royalty Trust since July 11, 1996. Over that time period we have earned a reputation for investing wisely in our assets and creating value for our unitholders. Over the past nine years we have spent $3.1 billion to acquire and develop our assets and have distributed $1.6 billion to our investors. We believe these are important contributions to the Canadian economy that must not be overlooked.

ARC is a member of the Canadian Association of Income Funds ("CAIF") and will support CAIF in making submissions as part of the consultation process.

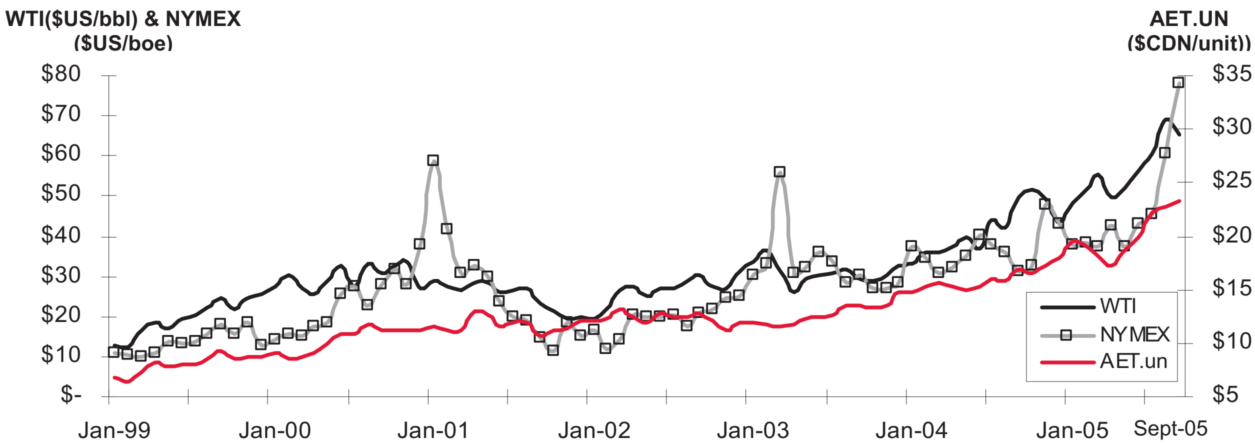
John Dielwart

John P. Dielwart
Director, President and
Chief Executive Officer

ACCOMPLISHMENTS / FINANCIAL UPDATE

- The major financial occurrence in the third quarter of 2005 was the significant rise in commodity prices. On September 30, 2005 West Texas Intermediate ("WTI") was US$65.55 per barrel and the AECO natural gas price was $9.55 per mcf. Volatility has increased in both oil and North American natural gas prices due to a number of events impacting worldwide supply and demand for oil and natural gas. Commodity prices are a key component in determining cash flow and cash distributions and the level of unit prices in the oil and gas royalty trust sector. Commodity prices have been on an upward trend since early 1999 but have increased more dramatically since January 2003. As illustrated by the chart below, WTI oil prices are up 110 per cent for the period January 2003 to September 30, 2005 and NYMEX natural gas prices are up 185 per cent.

AET.UN vs. WTI and NYMEX* (6:1)



*NYMEX Natural Gas has been converted on a BOE basis using a 6:1 ratio

- As a response to the high commodity prices and the consistent performance of the Trust's diverse base of oil and gas properties, the Trust announced an increase in cash distributions from $0.15 per unit per month as of the August 31 date of record to $0.17. Subsequent to the quarter end on October 17, 2005, the Trust announced a further increase in distributions to $0.20 per unit per month for the October 31 date of record and November 15 payment date.

- The second distribution increase was a response to the recent rise in natural gas prices and the expected impact on the Trust's cash flow as ARC's total production for the nine months ended September 30, 2005 comprised 52 per cent natural gas.

- ARC realized cash flow of $168.1 million ($0.88 per trust unit) in the third quarter of 2005, 52 per cent higher than in the third quarter of 2004 ($0.59 per trust unit). Cash flow increased through strong commodity prices on a slightly lower production volume, while maintaining operating costs at the same level as in the prior year quarter.

- The Trust declared cash distributions of $92.6 million ($0.49 per trust unit) in the third quarter of 2005, resulting in a payout ratio of 55 per cent for the quarter and a 60 per cent payout ratio for the nine months ended September 30, 2005.

- Production averaged 55,592 boe per day in the third quarter of 2005, one per cent lower than the 56,096 boe per day production in the third quarter of 2004. The Trust was very active in the third quarter, spending $83 million on capital development activities ($181.1 million for year to date) within the Trust's core operating areas.

- The Trust realized an operating netback, before hedging, of $40.16 per boe in the third quarter of 2005 compared to $27.88 per boe in the third quarter of 2004 representing a 44 per cent increase.

MANAGEMENT’S DISCUSSION AND ANALYSIS

Management’s discussion and analysis (“MD&A”) should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2004.

This MD&A was written on November 1, 2005.

Management uses cash flow 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. All references to cash flow throughout this MD&A are based on cash flow before changes in non-cash working capital and expenditures on site restoration and reclamation.

Management uses certain key performance indicators (“KPI’s”) and industry benchmarks such as operating netbacks (“netbacks”), total capitalization and payout ratios to analyze financial and operating performance. 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.

This discussion and analysis contains forward-looking statements relating to future events or future performance. 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 necessarily involve known and unknown risks and uncertainties, including the business risks discussed in the MD&A as at and for the year ended December 31, 2004, 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 implemented new accounting policies in the fourth quarter of 2004 pursuant to requirements of the Canadian Institute of Chartered Accountants (“CICA”). Certain amounts presented for comparative purposes have been restated as a result of the retroactive application of these new policies and instruments. See “Impact of New Accounting Policies” in this MD&A for a detailed description of the impact on reported results.

Highlights

	Three Months Ended September 30		Nine Months Ended September 30	
(CDN$ millions, except per unit and volume data)	**2005**	2004	**2005**	2004
Cash flow from operations	**168.1**	110.8	**431.9**	341.1
Cash flow from operations per unit (3)	**0.88**	0.59	**2.27**	1.84
Net income	**114.6**	38.9	**226.5**	128.7
Distributions per unit	**0.49**	0.45	**1.39**	1.35
Payout ratio per cent (1)	**55**	75	**60**	72
Daily production (boe/d) (2)	**55,592**	56,096	**55,288**	57,102

(1) Based on cash distributions divided by cash flow from operations.
(2) Reported production amount is based on company interest before royalty burdens.
(3) Per unit amounts (with the exception of per unit distributions) are based on weighted average units plus units issuable for exchangeable shares at period end.

Net Income

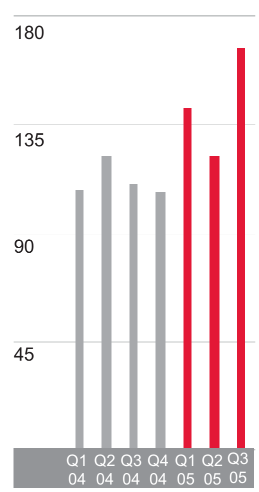
In the third quarter of 2005, net income nearly tripled to $114.6 million from $38.9 million in the third quarter of 2004. Higher commodity prices “fueled” this substantial increase in earnings. Earnings for the third quarter were approximately 68 per cent of cash flow versus 35 per cent of cash flow in the third quarter of 2004.

Cash Flow from Operations

Cash flow from operations increased 52 per cent to $168.1 million during the third quarter 2005 compared to $110.8 in the third quarter of 2004 as a result of higher commodity prices. To date in 2005, cash flow was $431.9 million, which is 27 per cent higher than the same period in 2004. This increase is attributed to increased commodity prices that outweighed the small decrease in production volumes and higher royalties. Also on the face of rising service costs, we were able to keep operating costs at the same level in the third quarter of 2005 versus 2004.

Cash flow in the third quarter of 2005 increased by 38 per cent over the second quarter of 2005 due to increased commodity prices.

CASH FLOW
(CDN$ millions)



Following is a summary of variances in cash flow from operations for the first nine months of 2004 relative to the first nine months of 2005:

Favourable (unfavourable)	$ millions	$ per trust unit [3]	% Variance [2]
Q3 YTD 2004 cash flow from operations	**$ 341.1**	**$ 1.84**	
Volume variance	(23.6)	(0.13)	(6)
Price variance	153.9	0.83	46
Change in cash losses on commodity and foreign currency contracts [1]	(5.4)	(0.03)	(2)
Royalties	(30.0)	(0.16)	(9)
Expenses:			
Transportation	0.2	-	-
Operating	1.4	0.01	-
Cash G&A	(4.7)	(0.03)	(1)
Interest	(0.6)	-	-
Capital taxes	0.5	-	-
Realized foreign exchange gain (loss)	(2.4)	(0.01)	(1)
Other	1.5	0.01	-
Weighted average trust units plus units issuable for exchangeable shares at period end	-	(0.06)	
Q3 YTD 2005 cash flow from operations	**$ 431.9**	**$ 2.27**	**27**

(1) Represents cash losses on commodity and foreign currency contracts including cash settlements on termination of commodity and foreign currency contracts.
(2) Variance is calculated based on $ millions column.
(3) Per unit amounts are based on weighted average units plus units issuable for exchangeable shares at period end.

Production

Production volumes decreased one per cent, averaging 55,592 boe/d in the third quarter of 2005 compared to 56,096 boe/d in the third quarter of 2004. To date, incremental production from the Trust's capital development program in 2005 did not offset the natural production declines on existing properties as wet weather caused some drilling and tie-ins to be delayed into the fourth quarter of 2005. At September 30, 2005, there was approximately 1,800 boe/d that had not yet been tied-in due to wet weather conditions. These volumes are expected in the fourth quarter of 2005. The Trust's annual objective is to drill wells and incur other development expenditures in order to maintain production at current levels. In fulfilling this objective, there may be fluctuations in production depending on drilling results and the timing of new wells coming on-stream.

Production [1]	Three Months Ended September 30 2005	2004	% Change	Nine Months Ended September 30 2005	2004	% Change
Crude oil (bbl/d)	**23,513**	22,496	5	**22,523**	22,958	(2)
Natural gas (mcf/d)	**168,194**	177,396	(5)	**172,432**	179,529	(4)
NGL (bbl/d)	**4,047**	4,034	-	**4,027**	4,223	(5)
Total production (boe/d)	**55,592**	56,096	(1)	**55,288**	57,102	(3)
% Natural gas production	**50**	47		**52**	48	
% Crude oil and liquids production	**50**	53		**48**	52	

[1] Reported production for a period may include minor adjustments from previous production periods.

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

	Q3 2005				Q3 2004			
Core Areas [1]	**Total (boe/d)**	**Oil (bbls/d)**	**Gas (mcf/d)**	**NGL (bbls/d)**	Total (boe/d)	Oil (bbls/d)	Gas (mcf/d)	NGL (bbls/d)
Central AB	**7,550**	**1,337**	**27,936**	**1,557**	8,782	1,721	31,938	1,738
Northern AB & BC	**18,152**	**6,073**	**63,815**	**1,443**	18,973	5,653	71,406	1,419
Pembina	**7,862**	**3,916**	**18,333**	**891**	7,575	3,899	17,562	749
S.E. AB & S.W. Sask.	**10,878**	**1,487**	**56,233**	**19**	10,649	1,569	54,424	9
S.E. Sask.	**11,150**	**10,700**	**1,877**	**137**	10,117	9,654	2,066	119
Total	**55,592**	**23,513**	**168,194**	**4,047**	56,096	22,496	177,396	4,034

	YTD 2005				YTD 2004			
Core Areas [1]	**Total (boe/d)**	**Oil (bbls/d)**	**Gas (mcf/d)**	**NGL (bbls/d)**	Total (boe/d)	Oil (bbls/d)	Gas (mcf/d)	NGL (bbls/d)
Central AB	**7,975**	**1,386**	**29,463**	**1,679**	9,516	2,114	33,291	1,853
Northern AB & BC	**18,072**	**5,859**	**65,105**	**1,363**	19,273	5,701	72,683	1,458
Pembina	**7,568**	**3,734**	**18,009**	**832**	7,413	3,730	17,410	782
S.E. AB & S.W. Sask.	**11,187**	**1,495**	**58,058**	**16**	10,747	1,686	54,285	14
S.E. Sask.	**10,486**	**10,049**	**1,797**	**137**	10,153	9,727	1,860	116
Total	**55,288**	**22,523**	**172,432**	**4,027**	57,102	22,958	179,529	4,223

[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

Benchmark prices	Three Months Ended September 30			Nine Months Ended September 30		
	2005	2004	% Change	**2005**	2004	% Change
AECO gas (CDN$/mcf) [1]	**8.00**	6.67	20	**7.36**	6.69	10
WTI oil (US$/bbl) [2]	**63.16**	43.84	44	**55.45**	39.13	42
CAD/USD foreign exchange rate	**1.20**	1.32	(9)	**1.22**	1.33	(8)
WTI oil (CDN$/bbl)	**75.89**	57.31	32	**67.85**	51.95	31

(1) Represents the AECO monthly posting.
(2) WTI represents West Texas Intermediate posting as denominated in US$.

ARC's realized prices have increased 35 per cent since the fourth quarter of 2004. On October 15, 2005 WTI oil was priced at over US$63.00, close to the prices received in the third quarter of 2005 and natural gas at over US$13.00 is currently 60 per cent higher than the third quarter 2005 prices received.

Prior to hedging activities, ARC realized a price of $60.66 per boe on third quarter 2005 production, a 36 per cent increase over the $44.72 per boe received in 2004.

The following is a summary of realized prices before hedging activities:

ARC Realized Prices [1]	Three Months Ended September 30			Nine Months Ended September 30		
	2005	2004	% Change	**2005**	2004	% Change
Oil ($/bbl)	**69.37**	51.00	36	**60.72**	46.20	31
Natural gas ($/mcf)	**9.08**	6.65	37	**7.89**	6.77	17
Total commodity revenue before hedging ($/boe)	**60.66**	44.72	36	**52.99**	42.80	24

(1) Prices as reported above are prior to gains and losses on commodity and foreign currency contracts and are prior to transportation charges. All gains and losses on commodity and foreign currency contracts are included in "loss on commodity and foreign currency contracts" in the statement of income.

Revenue

Revenue before hedging increased 34 per cent to $310.2 million in the third quarter of 2005 compared to $230.8 million in the third quarter of 2004. This increase in revenue was primarily attributable to significantly higher commodity prices.

A breakdown of revenue, before hedging activities, is as follows:

	Three Months Ended September 30			Nine Months Ended September 30		
Revenue ($ thousands) [1]	**2005**	2004	% Change	**2005**	2004	% Change
Oil revenue	**150,065**	105,555	42	**373,334**	290,649	28
Natural gas revenue	**140,450**	108,585	29	**371,509**	332,937	12
NGL's revenue	**18,777**	15,700	20	**52,471**	43,408	21
Total commodity revenue	**309,292**	229,840	35	**797,314**	666,994	20
Other revenue	**957**	929	3	**2,585**	2,676	(3)
Total revenue before hedging [1]	**310,249**	230,769	34	**799,899**	669,670	19

(1) Revenue as reported above is prior to gains and losses on commodity and foreign currency contracts and prior to transportation charges. All gains and losses on commodity and foreign currency contracts are included in "loss on commodity and foreign currency contracts" in the statement of income.

Risk Management and Hedging Activities

The Trust's risk management activities are conducted by an internal Risk Management Committee, based upon guidelines approved by the Board, which encompasses a variety of controls including approval of credit worthy counterparties.

In response to the continued volatility within the commodity markets, the Trust continues to execute a risk management strategy focused on price floor (put) structures to manage commodity prices and continues to use fixed rate swaps to manage foreign exchange and interest rate exposures. The purchase of a price floor involves paying a premium to limit the exposure to downturns in commodity prices while participating in commodity price appreciation. The Trust considers these contracts to be effective economic risk management structures as they meet the objectives of the Trust's risk management mandate.

ARC's current risk management portfolio for the remainder of 2005 and 2006 are detailed in Note 6 of the unaudited interim consolidated financial statements.

Due to the implementation of a floor, or put strategy, in November 2004, approximately 83 per cent of the Trust's fourth quarter 2005 oil and natural gas liquids and 76 per cent of the natural gas production will participate in the market price appreciation. The Trust currently has downside protection on approximately 39 per cent of the Trust's fourth quarter production, at prices above budgeted levels required to maintain distributions. For 2006, the Trust has 100 per cent upside on both oil and natural gas production and downside protection on approximately 17 per cent of production consisting of 24 and 11 per cent of oil and gas production respectively.

For 2006, the Trust has downside price protection on an average of 7,000 bbl/d of oil production with an average floor price of US$52.68. The Trust has downside price protection on an average of 21,725 GJ/d of 2006 natural gas production with an average floor price of CDN$8.35/mcf.

The Trust is committed to pay $18.8 million in option premiums related to puts purchased to protect Q4 2005 and 2006 cash flows. The premiums on the put contracts will be recorded as a realized hedging cash 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.

The Trust unwound US$32 million of interest rate swaps in September 2005. Since entering into the swap in April 2004, the Trust realized a net gain of CDN$1.1 million. The Trust will now be subject to the original fixed coupon rate of 4.62 per cent.

Gain or Loss on Commodity and Foreign Currency Contracts

Gain or loss on commodity and foreign currency contracts comprised realized and unrealized gains or losses on commodity and foreign currency contracts that do not meet the requirements of an effective accounting 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 expense in the statement of income.

The Trust recorded a loss on commodity and foreign currency contracts of $14.3 million in the third quarter of 2005, comprising an unrealized fair value gain of $12.2 million and a realized cash loss of $26.5 million.

The following is a summary of the gain (loss) on commodity and foreign currency contracts for the third quarters of 2005 and 2004:

Commodity and foreign currency contracts ($ thousands)	**Crude Oil & Liquids**	**Natural Gas**	**Foreign Currency**	**Q3 2005 Total**	Q3 2004 Total
Realized cash gain (loss) on contracts (1)	**(20,937)**	**(6,455)**	**814**	**(26,578)**	(24,183)
Non-cash gain on contracts (2)	**-**	**-**	**-**	**-**	1,062
Non-cash amortization of opening deferred hedge (loss) (3)	**-**	**-**	**-**	**-**	(1,921)
Unrealized gain (loss) on contracts, change in fair value (4)	**14,439**	**(7,868)**	**5,676**	**12,247**	(28,128)
Total gain (loss) on commodity and foreign currency contracts	**(6,498)**	**(14,323)**	**6,490**	**(14,331)**	(53,170)

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

(2) The non-cash gain of $1.1 million for 2004 represents non-cash amortization of deferred commodity and foreign currency contracts. The deferred commodity and foreign currency contracts were fully amortized at December 31, 2004.

(3) Represents non-cash amortization of the opening deferred hedge loss of $14.6 million to income over the terms of the contracts in place at January 1, 2004. The opening deferred hedge loss was fully amortized at December 31, 2004.

(4) The unrealized loss on contracts represents the change in fair value of the contracts during the period. The fair value of the contracts was a loss of $44.4 million as at June 30, 2005 and a loss of $32.2 million as at September 30, 2005.

Operating Netbacks

The Trust's operating netback, after realized hedging losses, increased 49 per cent to $34.96 per boe in the third quarter of 2005 compared to $23.40 per boe in the third quarter of 2004. The increase in netbacks in 2005 is due to higher realized commodity prices.

The netbacks incorporate realized losses on commodity and foreign currency contracts of $5.20 per boe for the third quarter of 2005, compared to losses of $4.48 per boe in the third quarter of 2004. (Unrealized fair value changes on commodity and foreign currency contracts of a gain of $12.2 million and a loss of $28.1 million in the third quarter of 2005 and 2004, respectively, were not recorded as a reduction of the netback).

The components of operating netbacks are shown below:

	Q3 2005				Q3 2004
Netback	Oil ($/bbl)	Gas ($/mcf)	NGL ($/bbl)	**Total ($/boe)**	Total ($/boe)
Weighted average sales price	69.37	9.08	50.42	**60.47**	44.54
Other revenue	-	-	-	**0.19**	0.18
Total revenue	69.37	9.08	50.42	**60.66**	44.72
Royalties	(13.95)	(1.98)	(12.20)	**(12.77)**	(9.17)
Transportation	(0.09)	(0.21)	-	**(0.66)**	(0.69)
Operating costs (1)	(8.69)	(0.99)	(5.67)	**(7.07)**	(6.98)
Netback prior to hedging	46.64	5.90	32.55	**40.16**	27.88
Realized loss on commodity and fx contracts(2)	(9.30)	(0.42)	-	**(5.20)**	(4.48)
Netback after hedging	37.34	5.48	32.55	**34.96**	23.40

	YTD 2005				YTD 2004
Netback	Oil ($/bbl)	Gas ($/mcf)	NGL ($/bbl)	**Total ($/boe)**	Total ($/boe)
Weighted average sales price	60.72	7.89	47.73	**52.82**	42.63
Other revenue	-	-	-	**0.17**	0.17
Total revenue	60.72	7.89	47.73	**52.99**	42.80
Royalties	(11.77)	(1.61)	(12.25)	**(10.72)**	(8.42)
Transportation	(0.14)	(0.21)	-	**(0.71)**	(0.70)
Operating costs (1)	(8.32)	(1.00)	(4.66)	**(6.84)**	(6.69)
Netback prior to hedging	40.49	5.07	30.82	**34.72**	26.99
Realized loss on commodity and fx contracts(2)	(9.41)	(0.07)	-	**(4.05)**	(3.27)
Netback after hedging	31.08	5.00	30.82	**30.67**	23.72

(1) Operating expenses are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions have been made in allocating these costs between oil, natural gas and natural gas liquids production.
(2) Excludes unrealized fair value changes on commodity and foreign currency fx contracts of a gain of $12.2 million and a loss of $29 million in the third quarters of 2005 and 2004, respectively.

Royalties increased to $10.72 per boe in the third quarter of 2005 compared to $8.42 per boe in the third quarter of 2004. The increase in royalties per boe is the result of higher commodity prices in the third quarter of 2005 relative to 2004.

Royalties as a percentage of pre-hedged commodity revenue net of transportation costs increased two per cent to 21.3 per cent compared to 20.8 per cent in the third quarter of 2004 due to the Saskatchewan resources surcharge introduced to trusts in April 2005. Royalties are calculated and paid based on commodity revenue net of associated transportation costs and before any commodity hedging gains or losses.

Operating costs increased slightly to $36.2 million in the third quarter of 2005 compared to $36 million in the same period of 2004. Operating costs were $7.07 per boe for the third quarter of 2005 compared to $6.98 per boe in the third quarter of 2004. There has been upward pressure on operating costs during the third quarter in all areas of operations but operating staff have done an effective job of holding costs in line.

The Trust expects the trend of increasing costs to continue for the remainder of 2005 and in 2006, as the demand for services remains at unprecedented levels. Consequently, ARC expects 2005 average annual operating costs to increase from 2004 levels to average approximately $7.00 per boe.

Transportation costs decreased slightly to $0.66 per boe in the third quarter of 2005, compared to $0.69 per boe in the third quarter of 2004. Transportation costs are defined by the point of legal transfer of the product and are dependent upon where the product is sold, product split, location of properties, and industry transportation rates. For the majority of ARC's gas production, legal title transfers at the intersection of major pipelines (referred to as "the Hub") whereas the majority of ARC's oil production is sold at the outlet to the field oil battery. Consequently, there are higher transportation costs incurred directly by ARC with gas production due to the distance from the wellhead to the Hub.

General and Administrative Expenses and Trust Unit Incentive Compensation

G&A and Trust Unit Incentive Compensation Expense ($ thousands except per boe)	Three Months Ended September 30			Nine Months Ended September 30		
	2005	2004	% Change	**2005**	2004	% Change
Cash component:						
G&A prior to whole unit plan	**6,275**	4,928	27	**18,833**	15,213	24
Per boe	**1.23**	0.96	28	**1.25**	0.97	29
Whole unit plan expense	**107**	-	100	**1,062**	-	100
Cash G&A expense	**6,382**	4,928	30	**19,895**	15,213	31
Per boe	**1.25**	0.96	30	**1.32**	0.97	36
Non cash components:						
Rights plan	**1,399**	3,286	(57)	**4,881**	6,696	(27)
Whole unit plan	**2,239**	876	156	**2,645**	1,521	74
	10,020	9,090	10	**27,421**	23,430	17
Per boe	**1.96**	1.76	11	**1.82**	1.50	21

G&A expense was up over the prior year primarily due to increased staff compensation costs and increased number of staff due to an expansion of the Trust's capital expenditure program.

The Rights Plan, which has been discontinued with the introduction of the Trust's Whole Unit Trust Incentive Plan, has 1.5 million rights outstanding at the end of the quarter. The expenses associated with the Rights Plan were $1.4 million in the quarter compared to $3.3 million in 2004.

It is the Trust's strategy to ensure compensation levels are competitive with industry peers and to ensure that ARC continues to attract and retain highly qualified individuals. As such, internal benchmarking shows ARC's total G&A being in the mid-range compared to the Trust's peers in the conventional oil and gas sector.

With higher commodity prices the industry is responding with a record number of new oil and gas wells drilled and oilsands projects commenced or expanded. All of these activities result in a significant requirement for trained skilled employees. Recruitment of new staff and retention of existing employees is a major challenge of oil and gas companies and trusts in western Canada.

We believe that the Trust has fared well against our competitors with both retention and attraction of new staff but we are very cognizant of the issues. The Trust and its subsidiaries currently employ approximately 340 permanent and consulting employees (versus 318 last year at this time) in the management of the business. ARC has a team of highly skilled individuals in the geological, geophysical and engineering exploitation areas that generate the Trust's drilling prospects. At this time we believe we are adequately staffed to continue to diligently execute our capital budget of $270 million.

The importance of people and their unique expertise is a core concern to ARC and as a result, we have focused considerable energy into reviewing our compensation plan to ensure we are attracting and retaining highly skilled and talented employees. At the end of this review, we have determined that:

- We are able to attract new staff to ARC based on our current compensation philosophy;
- Attrition has occurred at ARC, but is low compared to industry standards; and
- Enhancement of current employee compensation plans have occurred resulting in an estimated $1.45 per boe cash G&A for the fourth quarter of 2005. This area will be the focus for fiscal 2006 to ensure the Trust remains competitive.

The Trust with the guidance of the Human Resources and Compensation Committee of the Board of Directors will continue to closely monitor this situation to ensure that the Trust is competitive on compensation in order to attract and retain a highly competent, results driven work force.

Interest Expense

Interest expense increased to $4.5 million in the third quarter of 2005 from $2.9 million in the third quarter of 2004 reflecting the higher level of debt in the 2005 quarter.

Debt is higher in the third quarter 2005 over the third quarter of 2004 due to second quarter 2005 acquisitions funded entirely through debt.

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

Interest Expense	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2005**	2004	% Change	**2005**	2004	% Change
Period end debt balance [1]	**315,814**	241,176	31	**315,814**	241,176	31
Fixed rate debt	**212,482**	240,141	(12)	**212,482**	240,141	(12)
Floating rate debt	**103,332**	1,035		**103,322**	1,035	
Interest expense before interest rate swaps [2]	**4,590**	3,521	30	**10,491**	11,385	(8)
Loss (Gain) on interest rate hedge	**(129)**	(577)	(78)	**444**	(1,050)	142
Net interest expense	**4,461**	2,944	52	**10,935**	10,335	6

(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 gain of $11.9 million on foreign exchange transactions in the third quarter of 2005 compared to a gain of $14.4 million in the third quarter of 2004. Year to date foreign exchange gains are $7.8 million and $9.4 million for 2005 and 2004, respectively. 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 USD/CAD exchange rate was relatively stable during the third quarter of 2005. 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.

Taxes

In the third quarter of 2005, a future income tax expense of $5.7 million was included in income compared to a $6 million recovery in the third quarter of 2004. The higher future income tax expense in 2005 relative to 2004 was due to the higher unrealized gains on commodity and foreign currency contracts of $12.2 million in the third quarter of 2005 compared to $29 million loss in the third quarter of 2004.

ARC's expected future income tax rate is approximately 34 per cent compared to the current rate of approximately 38 per cent applicable to the 2005 income tax year.

Under existing tax legislation in the Trust's structure, payments are made between ARC Resources and the Trust, transferring both income and future tax liability to the unitholders. At the current time, ARC does not anticipate any cash income taxes will be paid in fiscal 2005 by ARC Resources.

Depletion, Depreciation and Accretion of Asset Retirement Obligation

The depletion, depreciation and accretion ("DD&A") rate increased to $12.86 per boe in the third quarter of 2005 from $11.40 per boe in 2004. The higher DD&A rate is due to an increase in future development capital per the Trust's January 1, 2005 reserve evaluation compared to the January 1, 2004 reserve evaluation. In addition, the higher asset retirement obligation recorded in 2005 has resulted in a higher accretion expense in 2005.

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

DD&A Rate	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except per boe amounts)	**2005**	2004	% Change	**2005**	2004	% Change
Depletion of oil & gas assets [1]	**64,450**	57,715	12	**186,964**	173,713	8
Accretion of asset retirement obligation [2]	**1,347**	1,124	20	**3,860**	3,457	12
Total DD&A	**65,797**	58,839	12	**190,824**	177,170	8
DD&A rate per boe	**12.86**	11.40	13	**12.64**	11.32	12

(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 period.

Goodwill

The goodwill balance of $157.6 million arose as a result of the acquisition of Star Oil and Gas Ltd. ("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 September 30, 2005.

Capital Expenditures and Net Acquisitions

Total capital expenditures, excluding acquisitions and dispositions, totaled $83.1 million in the third quarter of 2005 compared to $55.4 million in the third quarter of 2004. This amount was incurred on drilling and completions, geological, geophysical and facilities expenditures, as ARC continues to develop its asset base.

The Trust's strategy is to fully exploit its asset base and to increase the recoverable portion of total oil and natural gas reserves in place on land owned by the Trust.

So far this year the Trust has drilled 189 operated wells (167 operated wells in the third quarter) out of a total of 291 planned for 2005. During the third quarter of 2005, ARC completed two property swaps resulting in $17 million in property acquisitions and $17 million in property dispositions.

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

	Three Months Ended September 30		Nine Months Ended September 30	
Capital Expenditures ($ thousands)	**2005**	2004	**2005**	2004
Geological and geophysical	**2,258**	828	**6,178**	4,521
Drilling and completions	**65,676**	42,553	**135,189**	105,362
Plant and facilities	**14,803**	11,668	**37,995**	34,906
Other capital	**317**	394	**1,690**	1,341
Total capital expenditures	**83,054**	55,443	**181,052**	146,130
Producing property acquisitions [1]	**22,845**	(2,105)	**108,215**	404
Producing property dispositions [1]	**(16,985)**	(3,240)	**(19,965)**	(57,587)
Corporate acquisition [1] [2]	**-**	-	**62,456**	30,560
Total capital expenditures and net acquisitions	**88,914**	50,098	**331,758**	119,507
Capital expenditures and net acquisitions financed with cash flow	**73,842**	26,156	**162,024**	85,406
Capital expenditures and net acquisitions financed with debt and equity	**15,072**	23,942	**169,734**	34,101

(1) Value is net of post-closing adjustments.
(2) Represents total consideration for the transaction including fees and prior to the future income tax liability assumed on acquisition.

Asset Retirement Obligation and Reclamation Fund

At September 30, 2005, the Trust has recorded an Asset Retirement Obligation ("ARO") of $81.5 million ($64.4 million at September 30, 2004) for future abandonment and reclamation of the Trust's properties. The ARO increased by $1.3 million for accretion expense and was reduced by $0.9 million for actual abandonment expenditures incurred in the third quarter of 2005. The Trust did not record a gain or loss on actual abandonment expenditures incurred in 2005 as the costs closely approximated the liability value included in the ARO.

ARC contributed $1.5 million cash to its reclamation fund in the third quarter of 2005 ($1.5 million in the third quarter of 2004) and earned interest of $0.2 million on the fund balance. The fund balance was reduced by $0.7 million for cash-funded abandonment expenditures in the third quarter of 2005 ($0.7 million in the third quarter of 2004). This fund, which aggregated $23.3 million as of September 30, 2005, is invested in money market instruments and is established to provide for future abandonment and reclamation liabilities. Future contributions are currently set at approximately $6 million per year over 20 years in order to provide for the total estimated future abandonment and reclamation costs that are to be incurred over the next 61 years. The annual funding of the reclamation fund results in all unitholders over time sharing in the cost of the eventual abandonment of the Trust's properties.

Capitalization, Financial Resources and Liquidity

A breakdown of the Trust's capital structure is as follows:

Capitalization, Financial Resources and Liquidity ($ thousands except per unit and per cent amounts)	**September 30, 2005**	June 30, 2005	March 31, 2005	December 31, 2004
Long-term debt	**307,686**	311,049	218,189	211,834
Short-term debt	**8,128**	8,579	8,467	8,715
Working capital deficit excluding short-term debt [1]	**41,746**	46,588	27,596	44,293
Net debt obligations	**357,560**	366,216	254,252	264,842
Units outstanding and issuable for exchangeable shares (thousands)	**192,089**	191,329	189,609	188,804
Market price per unit at end of period	**24.10**	19.94	18.15	17.90
Market value of trust units and exchangeable shares	**4,629,345**	3,815,100	3,441,403	3,379,592
Total capitalization [2]	**4,986,905**	4,181,316	3,695,655	3,644,434
Net debt as a percentage of total capitalization	**7.2%**	8.8%	6.9%	7.3%
Cash flow from operations	**431,891**	263,774	141,965	448,033
Net debt to annualized cash flow	**0.6**	0.7	0.4	0.6

(1) The working capital deficit excludes the net current liability for the fair value of 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 Trust's credit facilities are consolidated into one syndicated credit facility with a total borrowing base of $620 million. ARC Resources' and ARC (Sask) Trust's oil and gas properties continue to secure the debt.

As at September 30, 2005 net debt to total capitalization was 7.2 per cent and net debt to annualized third quarter year to date 2005 cash flow was approximately 0.6 times (0.6 times at December 31, 2004), well within the Trust's objective of net debt at or below the 1.0 times cash flow during high commodity price environments.

The Trust funded 89 per cent of its third quarter capital development program of $83.1 million with cash flow. The balance of capital expenditures were funded by proceeds from the distribution reinvestment program and the exercise of employee rights.

Unitholders' Equity

At September 30, 2005, there were 192.1 million trust units issued and issuable for exchangeable shares, a slight increase from the 188.8 million trust units issued and issuable for exchangeable shares at December 31, 2004. The increase in the number of trust units outstanding is attributable to trust units issued pursuant to the Distribution Reinvestment Incentive Plan ("DRIP"), trust units issued pursuant to the exercise of employee rights and trust units issued upon conversion of exchangeable shares.

The existing rights plan will be in place until the remaining 1.5 million rights outstanding as of September 30, 2005 are exercised or cancelled as no additional rights will be issued under the plan due to discontinuation of the plan in the third quarter of 2004. The holder has the option to exercise the rights at the original grant price or a price which is adjusted downward over time by the amount, if any, of the annual distributions that exceed 10 per cent of the net book value of the property, plant and equipment. The rights have a five-year term and vest equally over three years from the date of grant. Rights to purchase 1.5 million trust units at an average adjusted exercise price of $10.55 were outstanding at September 30, 2005. These rights have an average remaining contractual life of 2.5 years and expire at various dates to March 22, 2009.

The Whole Unit Plan results in the issuance of a certain number of underlying trust units to employees, officers and directors of the Trust. The underlying trust units take the form of Restricted Trust Units ("RTU's"), which vest equally over three years or Performance Trust Units ("PTU's") that vest in total at the end of three years. Upon vesting, the individual receives a cash payment equal to the current value of the underlying trust units including accrued distributions. Consequently, the Whole Unit Plan is a cash plan whereby there will be no trust units being issued from treasury under the plan. At September 30, 2005 there were 0.7 million RTU's and PTU's outstanding under the Whole Unit Plan. Each year, additional RTU's and PTU's will be issued to employees, officers and directors of the Trust. The Trust has made provisions whereby employees may elect to have trust 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 trust 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.

Non-Controlling Interest

The Trust has recorded non-controlling interest attributed to the issued and outstanding exchangeable shares of ARC Resources Ltd. ("ARL"), a corporate subsidiary of the Trust, in accordance with new accounting requirements pursuant to EIC-151 (see "Impact of New Accounting Policies" section of this MD&A for further discussion). The intent of the new standard is that exchangeable shares of a subsidiary that are transferable to third parties, outside of the consolidated entity, represent a non-controlling interest in the subsidiary.

The exchangeable shares of ARL are publicly traded and therefore are transferable to third parties within a period of time. The exchangeable shares rank equally with the trust units and the two are considered to be economically equivalent. There are no provisions whereby the exchangeable shareholders have certain rights or terms that are not eligible to the Trust unitholders. Therefore, the Trust does not believe that there is a permanent non-controlling interest as all exchangeable shares will ultimately be converted to trust units either by means of redemption by the exchangeable shareholders or by passage of time whereby ARL will redeem the exchangeable shares for trust units. Consequently, as the exchangeable shares are redeemed for trust units over time, the non-controlling interest will decrease and eventually will be nil when all exchangeable shares have been converted to trust units on or before August 29, 2012. However, the Trust has reflected the non-controlling interest in accordance with the requirements of EIC-151.

The non-controlling interest of $36.5 million at September 30, 2005 ($36 million at December 31, 2004) on the consolidated balance sheet represents the book value of exchangeable shares plus accumulated earnings attributable to the outstanding exchangeable shares. The reduction in third quarter 2005 and 2004 net income, respectively, of $1.8 million and $0.6 million, represents the net income attributable to the exchangeable shareholders for the third quarters of 2005 and 2004, respectively. As the exchangeable shares are converted to trust units, Unitholders' capital is increased by the book value of the trust units issued.

As at September 30, 2005 there were 1.6 million exchangeable shares of ARL outstanding at an exchange ratio of 1.79533 whereby 2.9 million trust units would be issuable upon conversion. The exchangeable shares can be converted into trust units or redeemed by the exchangeable shareholder for trust units at any time. ARL may redeem all outstanding exchangeable shares on or before August 29, 2012 and may redeem the exchangeable shares at any time if the number of exchangeable shares outstanding falls below 100,000 shares. ARL may issue cash or trust units upon redemption of exchangeable shares and it is the intention to issue trust units upon redemption.

The new standard has been applied retroactively with restatement of prior periods. Consequently, previously reported third quarter 2004 net income has been restated to reflect the impact of the new standard. See "Impact of New Accounting Policies" in this MD&A for a quantification of the impact of this standard.

Cash Distributions

ARC declared cash distributions of $92.6 million ($0.49 per unit), representing 55 per cent of third quarter 2005 cash flow compared to cash distributions of $83.2 million ($0.45 per unit), representing 75 per cent of cash flow in the third quarter of 2004. The remaining 45 per cent of third quarter 2005 cash flow was used to fund 89 per cent of ARC's third quarter 2005 capital expenditures of $83.1 million, and make contributions to the reclamation fund. 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.

Cash flow and cash distributions were as follows:

	Three Months Ended September 30		%	Three Months Ended September 30		%
Cash flow and distributions	**2005**	2004	Change	**2005**	2004	Change
	($ millions)			($ per unit) (2)		
Cash flow from operations	**168.1**	110.8	52	**0.88**	0.59	49
Reclamation fund contributions (1)	**(1.7)**	(1.5)	13	**(0.01)**	(0.01)	-
Capital expenditures funded with cash flow	**(73.8)**	(26.1)	183	**(0.38)**	(0.14)	171
Other (2)	**-**	-	-	**-**	0.01	-
Cash distributions	**92.6**	83.2	11	**0.49**	0.45	9

Cash flow and distributions	Nine Months Ended September 30 2005	2004	% Change	Nine Months Ended September 30 2005	2004	% Change
	($ millions)			($ per unit) [2]		
Cash flow from operations	**431.9**	341.1	27	**2.27**	1.84	23
Reclamation fund contributions [1]	**(5.1)**	(5.0)	2	**(0.03)**	(0.03)	-
Capital expenditures funded with cash flow	**(162.0)**	(85.5)	89	**(0.85)**	(0.46)	(85)
Discretionary debt repayments	**(3.9)**	(4.2)	(7)	**(0.02)**	(0.02)	-
Other [2]	**-**	-	-	**0.02**	0.02	-
Cash distributions	**260.9**	246.4	6	**1.39**	1.35	3

(1) Includes interest income earned on the reclamation fund balance that is retained in the reclamation fund.
(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 period end.

Monthly cash distributions for the fourth quarter of 2005 have been set at $0.20 starting with the November 15, 2005 payment. 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 in each calendar period. Cash distributions for 2005 include distributions paid up to and including October 17, 2005:

Calendar Year	Distributions [1]	Taxable Portion	Return of Capital
2005 YTD [2]	1.54 [2]	1.46 [2]	0.08 [2]
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	**$15.63**	**$8.90**	**$6.73**

(1) Based on cash distributions paid in the calendar year.
(2) Based on cash distributions paid in 2005 up to and including October 17, 2005 and estimated taxable portion of 2005 distributions of 95 per cent.

2005 Monthly Cash Distributions

Actual cash distributions paid for 2005 along with relevant payment dates are as follows:

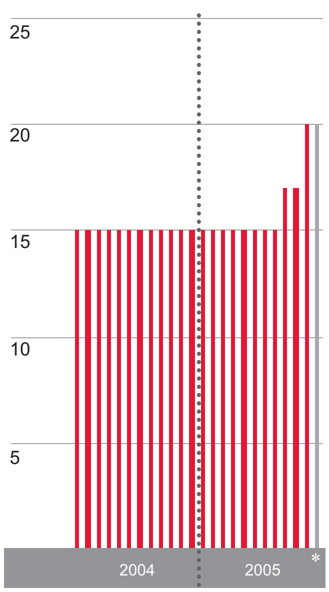
Ex-Distribution Date	Record Date	Distribution Payment Date	Total Distribution
December 29, 2004	December 31, 2004	January 15, 2005	0.15
January 27, 2005	January 31, 2005	February 15, 2005	0.15
February 24, 2005	February 28, 2005	March 15, 2005	0.15
March 29, 2005	March 31, 2005	April 15, 2005	0.15
April 27, 2005	April 30, 2005	May 16, 2005	0.15
May 27, 2005	May 31, 2005	June 15, 2005	0.15
June 28, 2005	June 30, 2005	July 15, 2005	0.15
July 27, 2005	July 31, 2005	August 15, 2005	0.15
August 28, 2005	August 31, 2005	September 15, 2005	0.17
September 28, 2005	September 30, 2005	October 17, 2005	0.17
October 27, 2005	October 31, 2005	November 15, 2005	0.20
November 28, 2005	November 30, 2005	December 15, 2005	0.20*
December 29, 2005	December 31, 2005	January 15, 2006	0.20*

* Estimated

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 trust units held. For a more detailed breakdown, please visit our website at www.arcenergytrust.com.

MONTHLY CASH DISTRIBUTIONS
(CDN cents/trust unit)



* Estimate based on current market outlook and subject to change based on actual market conditions

For 2005, it is estimated that cash distributions paid in the calendar year will be 95 per cent return on capital (taxable) and five per cent return of capital (tax deferred). The increase in the taxable portion of distributions to 95 per cent is the result of increasing commodity prices and in turn increasing cash flow of the Trust. Actual taxable amounts may differ from the estimated amount as they are dependent on commodity prices experienced throughout the year. Changes in the estimated taxable and deferred portion of the distributions will be announced quarterly.

The exchangeable shares of ARL may provide a more tax-effective basis for investment in the Trust. The ARL exchangeable shares are traded on the TSX under the symbol “ARX” and are convertible into trust units, at the option of the shareholder, based on the then current exchange ratio. Exchangeable shareholders are not eligible to receive monthly cash distributions, however the exchange ratio increases on a monthly basis by an amount equal to the current month’s trust unit distribution multiplied by the then current exchange ratio and divided by the 10 day weighted average trading price of the trust units at the end of each month. The gain realized as a result of the monthly increase in the exchange ratio is taxed, in most circumstances, as a capital gain rather than income and is therefore subject to a lower effective tax rate. Tax on the exchangeable shares is deferred until the exchangeable share is sold or converted into a trust unit.

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 listed in the table below.

See Note 15 of the unaudited interim consolidated financial statements for a list of contractual obligations.

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 approximately $40 to $60 million of capital expenditures by means of giving the necessary authorizations to incur the capital in a future period. 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.

Off Balance Sheet Arrangements

The Trust has certain minor lease agreements that are entered into in the normal course of operations. All leases are 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 September 30, 2005. The total obligation for future lease payments under all operating leases is disclosed in Note 15 of the unaudited interim consolidated financial statements.

The Trust entered into agreements to pay premiums pursuant to certain crude oil and natural gas derivative put contracts. Premiums of approximately $18.8 million will be paid in 2005 and 2006 for the put contracts in place at September 30, 2005. As the premiums are part of the underlying derivative contract, they have been recorded at fair market value at September 30, 2005 on the balance sheet. The total obligation for future premium payments is disclosed in the Note 15 of the unaudited interim consolidated financial statements.

Impact of New Accounting Policies

In 2004, the Trust implemented the following new accounting policies and instruments pursuant to requirements of the Canadian Institute of Chartered Accountants ("CICA"). The implementation of these new policies impacted the financial results for 2005 and comparative periods of 2004 as follows:

Non-Controlling Interest - On January 19, 2005 the CICA issued EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" which states that exchangeable securities issued by a subsidiary of an income trust should be reflected as either non-controlling interest or debt on the consolidated balance sheet unless they meet certain criteria. The exchangeable shares issued by ARC Resources Ltd. ("ARL"), a wholly owned corporate subsidiary of the Trust, are publicly traded and therefore are considered, by EIC-151, to be transferable to third parties. EIC-151 states that if the exchangeable shares are "transferable" to a third party, they should be reflected as non-controlling interest. Previously, the exchangeable shares were reflected as a component of Unitholders' equity. Accordingly, the Trust has reflected non-controlling interest of $36.5 million and $36 million, respectively, on the Trust's consolidated balance sheet as at September 30, 2005 and December 31, 2004. Consolidated net income has been reduced for net income attributable to the non-controlling interest of $1.8 million and $0.6 million, respectively, in the third quarter of 2005 and 2004. In accordance with the transitional provisions of EIC-151, retroactive application has been applied with restatement of prior periods. As a result of retroactive restatement, previously reported net income for the third quarter of 2004 has been reduced by $0.6 million to $38.9 million for the net income attributable to the non-controlling interest. In addition, previously reported cash flow per unit and net income per unit have been restated to reflect the weighted average trust units excluding trust units issuable for exchangeable shares.

Financial Reporting Update

In addition to the above policies implemented in 2004, the following new and amended standards have been reviewed by the Trust:

Redeemable or Retractable Shares – On November 5, 2004, the CICA issued EIC-149 "Accounting for Retractable or Mandatorily Redeemable Shares" that lists specific criteria required to be met in order for entities to reflect trust units and exchangeable shares as either a liability or equity in their financial statements. The trust units and exchangeable shares meet the required criteria to be reflected as Unitholders' equity and no additional presentation or disclosure is required.

Financial Instruments – Recognition and Measurement – On January 27, 2005 the Accounting Standard's Board (AcSB) issued CICA Handbook section 3855 "Financial Instruments – Recognition and Measurement", CICA Handbook section 1530 "Comprehensive Income" and CICA Handbook section 3865 "Hedges" that deal with the recognition and measurement of financial instruments and comprehensive income. The new standards are intended to harmonize Canadian standards with United States and International accounting standards and are effective for annual and interim periods in fiscal years beginning on or after October 1, 2006. These new standards will impact the Trust in future periods and the resulting impact will be assessed at that time.

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:

a) 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;
b) estimated capital expenditures on projects that are in progress;
c) estimated depletion, depreciation and accretion that are based on estimates of oil and gas reserves which the Trust expects to recover in the future;
d) estimated fair values of derivative contracts that are subject to fluctuation depending upon the underlying commodity prices and foreign exchange rates;
e) estimated value of asset retirement obligations that are dependent upon estimates of future costs and timing of expenditures; and
f) estimated future recoverable value of property, plant and equipment and goodwill.

The Trust has hired individuals and consultants who have the skill set to make such estimates and ensures 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.

Sarbanes Oxley Update

On July 31, 2002, the United States Congress enacted the Sarbanes Oxley Act ("SOX") that applies to all companies registered with the Securities and Exchange Commission ("SEC"). On March 2, 2005, the Securities and Exchange Commission ("SEC") announced a one year extension of the compliance date for all foreign private issuers. As a result of this extension, ARC is currently required to comply with section 404 of the SOX legislation on December 31, 2006. Section 404 of the SOX legislation "Internal Controls Over Financial Reporting" requires that management identify, document, assess, and remediate internal controls and issue an opinion on the effectiveness of internal controls surrounding the financial reporting process. The Trust currently has a comprehensive plan and a dedicated team of individuals in place to execute the plan of meeting the SOX Section 404 compliance date.

ARC's officers have established and maintain disclosure controls and procedures and evaluate the effectiveness of these controls in conjunction with the Trust's filings. ARC's officers have reviewed the Trust's disclosure procedures and controls with both the audit committee and the external auditors.

Objectives and 2005 Outlook

It is the Trust's objective to provide the highest possible long-term returns to unitholders by focusing on the key strategic objectives of the business plan.

During the first three quarters of 2005, the Trust provided unitholders with a pre-tax return of 45.8 per cent, assuming re-investment of cash distributions into additional trust units. This stellar return for the nine month period was primarily due to the increase in commodity prices as discussed in the accomplishments / financial highlights section of this report.

During the remainder of 2005, ARC will continue to be active with a robust drilling and development program on its diverse asset base. The initial $240 million capital expenditure budget for 2005 has been increased to $270 million to reflect increasing costs in the service sector, take advantage of enhanced opportunities in our asset base and accommodate forecast expenditures on newly acquired properties. The revised budget has been approved by the Board. The Trust will prudently deploy capital with a balanced drilling program of low and moderate risk wells. The 2004 drilling program resulted in a 99 per cent success rate and the Trust strives for the same success rate in 2005. The Trust continues to focus on major properties with significant upside, with the objective to replace production declines through internal development opportunities.

The low debt levels and strong working capital position provide the Trust with the financial flexibility to fund the 2005 capital expenditure program and be poised to take advantage of strategic acquisition opportunities. The Trust continually reviews potential acquisitions of both conventional oil and natural gas reserves and in the broader energy industry. Acquisitions are evaluated internally and acquisitions in excess of $10 million are subject to Board approval.

Following is a summary of the Trust's 2005 Annual Guidance issued by way of press release on January 3, 2005 and August 3, 2005, respectively, compared to reported actual results for the first nine months of 2005:

	2005 Annual Guidance		**2005 Actual**
	Original	**Revised**	**Q1, Q2 & Q3**
Production (boe/d)	54,800	56,000	55,288
Expenses ($/boe):			
Operating costs	7.00	7.00	6.84
Transportation	0.70	0.70	0.71
G&A expenses – cash	1.25	1.30	1.32
G&A expenses – stock compensation plans	0.30	0.55	0.50
Interest	0.75	0.75	0.72
Cash taxes	0.15	0.15	0.11
Capital expenditures ($ millions)	240	270	181
Weighted average trust units and units issuable (millions)	191.0	191.3	190.4

The Trust expects to complete the year 2005 in accordance with revised Guidance targets released in August 2005. To the end of the third quarter of 2005 there were some variances between annual guidance and actuals, however actuals are expected to converge with guidance targets as the year progresses with exceptions noted below.

The variance-to-date for operating costs is attributed to the seasonality of operating costs whereby the first quarter is typically the lowest cost quarter of the year and the second quarter is the highest. As workover and maintenance activities are undertaken in the third and fourth quarters, the Trust expects that actual operating costs will more closely approximate the guidance of $7.00 per boe for the year 2005.

The Trust expects non-cash G&A to be higher than the original annual guidance of $0.30 per boe as a result of the continued strength in the trust unit price that drives the value of non-cash compensation. The Trust currently estimates the 2005 annual non-cash G&A to approximate $0.50 to $0.70 per boe for the full year. As this is a non-cash amount, there is no impact on 2005 cash flow as a result of the revised guidance estimate.

Interest expense in the first half of 2005 was lower than the guidance target for 2005 as a result of record level of cash flow, which resulted in the Trust funding 90 per cent of its capital program with cash rather than debt. Consequently, debt levels and the corresponding interest expense were lower than anticipated during 2005. However, the Trust still expects interest to closely approximate the annual guidance of $0.75 per boe for the full year.

Cash taxes per boe of $0.11 for 2005 were below the guidance level of $0.15 as an overpayment of capital taxes in 2004 was returned to the Trust on assessment. In addition, the overall capital tax rate has commenced phase-out based on new federal legislation that eliminates the federal capital tax by 2006.

To the end of the third quarter, the Trust has incurred $181 million of capital expenditures. The Trust has significant capital development projects planned for the remainder of 2005 whereby the Trust expects to meet the revised annual 2005 capital expenditure guidance target of $270 million by the end of 2005.

See "Outlook" in the Trust's Annual Report MD&A for additional discussion of the Trust's key future objectives.

Cash Flow

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

			Impact on Annual Cash Flow	
Business environment	**Assumption**	**Change**	**$/Unit**	**%**
Oil price (US$WTI/barrel) [1]	$ 55.00	$ 1.00	$ 0.05	1.5%
Natural gas price (CDN$AECO/mcf) [1]	$ 8.00	$ 0.10	$ 0.03	1.0%
USD/CAD exchange rate	$ 0.83	$ 0.01	$ 0.06	1.7%
Interest rate on debt	5.3%	1.0%	$ 0.02	0.5%
Operational				
Liquids production volume (bbls/d)	27,000	1.0%	$ 0.02	0.6%
Gas production volumes (mmcf/d)	175.0	1.0%	$ 0.02	0.6%
Operating expenses per boe	$ 7.00	1.0%	$ 0.01	0.3%
Cash G&A expenses per boe	$ 1.30	10.0%	$ 0.02	0.5%

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

Assessment of Business Risks

The ARC management team is focused on long-term strategic planning and has identified the key risks, uncertainties and opportunities associated with the Trust's business that can impact the financial results. See "Assessment of Business Risks" in the Trust's 2004 Annual Report MD&A for a detailed assessment.

Unitholders and potential unitholders in the royalty trust sector should continue to evaluate their investment decisions in the context of future commodity prices. Additionally if future commodity prices are volatile it would be reasonable to expect that market prices of trust units would in turn be volatile. As discussed in the President's message of this quarterly report the Canadian government's review of the income trusts and the uncertainty that this review is creating is causing additional volatility in the trading prices of all trusts, including ARC, on the Toronto Stock Exchange. Any changes to existing tax legislation pertaining to trusts may have negative implications to the Trust and its' unitholders.

Additional Information

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

QUARTERLY REVIEW

(CDN$ thousands, except per unit amounts)	2005			2004				2003
FINANCIAL	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Revenue before royalties	**310,249**	251,596	238,054	232,112	230,769	233,307	205,594	182,558
Per unit (1)	**1.62**	1.32	1.26	1.23	1.23	1.26	1.12	1.04
Cash flow	**168,117**	121,808	141,965	106,935	110,835	122,249	108,014	89,617
Per unit (1)	**0.88**	0.64	0.75	0.57	0.59	0.66	0.59	0.51
Net income (5)	**114,600**	73,215	38,646	112,995	38,897	50,338	39,460	53,492
Per unit – basic (5) (6)	**0.61**	0.39	0.21	0.61	0.21	0.28	0.22	0.31
Per unit – diluted	**0.59**	0.38	0.20	0.60	0.21	0.27	0.22	0.31
Cash distributions	**92,559**	84,468	83,867	83,531	83,178	82,053	81,215	78,603
Per unit (2)	**0.49**	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Total assets (8)	**2,483,540**	2,427,463	2,303,948	2,304,998	2,316,297	2,309,599	2,278,608	2,281,775
Total liabilities (8)	**912,160**	895,179	785,776	755,650	804,603	768,073	752,166	730,039
Net debt outstanding (4)	**357,560**	366,216	254,252	264,842	220,500	220,074	284,001	262,071
Weighted average units (thousands) (3)	**188,770**	187,388	186,224	185,539	184,675	181,949	180,283	171,993
Units outstanding and issuable at period end (thousands)	**192,089**	191,329	189,609	188,804	188,185	187,296	183,980	182,777
CAPITAL EXPENDITURES ($ thousands)								
Geological and geophysical	**2,258**	2,659	1,262	867	828	1,373	2,320	2,846
Drilling and completions	**65,676**	33,465	36,042	39,125	42,553	24,867	37,942	37,738
Plant and facilities	**14,803**	8,703	14,495	6,183	11,668	7,282	15,956	15,512
Other capital	**317**	652	721	1,480	394	605	341	1,418
Total capital expenditures	**83,054**	45,479	52,520	47,655	55,443	34,127	56,559	57,515
Property acquisitions (dispositions), net	**5,860**	78,721	3,668	(1,036)	(5,345)	(53,412)	1,574	(3,693)
Corporate acquisitions (7)	**-**	62,456	-	41,449	-	30,560	-	-
Total capital expenditures and net acquisitions	**88,915**	186,656	56,188	88,068	50,098	11,275	58,133	53,822
OPERATING								
Production								
Crude oil (bbl/d)	**23,513**	22,046	21,993	22,969	22,496	22,720	23,663	22,851
Natural gas (mcf/d)	**168,194**	173,116	176,073	174.7	177.4	186.7	174.5	180.8
Natural gas liquids (bbl/d)	**4,047**	3,962	4,072	4,097	4,034	4,313	4,323	4,140
Total (boe/d 6:1)	**55,592**	54,860	55,410	56,179	56,096	58,147	57,075	57,120
Average prices								
Crude oil ($/bbl)	**69.37**	58.37	53.63	49.48	51.00	47.43	40.41	35.21
Natural gas ($/mcf)	**9.08**	7.42	7.20	6.82	6.65	6.99	6.64	5.85
Natural gas liquids ($/bbl)	**50.43**	46.13	46.57	43.72	42.30	38.22	32.30	30.14
Oil equivalent ($/boe) (9)	**60.66**	50.40	47.74	44.91	44.72	44.09	39.58	34.78
TRUST UNIT TRADING (based on intra-day trading)								
Unit prices								
High	**24.20**	20.30	20.40	17.98	17.38	15.74	15.74	14.87
Low	**19.94**	16.88	16.55	14.80	15.02	14.28	13.50	13.31
Close	**24.10**	19.94	18.15	17.90	16.85	15.35	15.64	14.74
Average daily volume (thousands)	**599**	605	895	456	384	337	502	395

(1) Based on weighted average trust units plus units issuable for exchangeable shares at period end.
(2) Based on number of trust units outstanding at each cash distribution date.
(3) Excludes trust units issuable for outstanding exchangeable shares.
(4) Total current and long-term debt net of working capital. Net debt excludes commodity and foreign currency contracts, the deferred hedge loss and deferred commodity and foreign currency contracts.
(5) Net income and net income per unit have been restated due to the retroactive application of the change in accounting policies relating to non-controlling interest that was implemented in 2004.
(6) Net income in the basic per trust unit calculation has been reduced by interest in the convertible debentures.
(7) Represents total consideration for the corporate acquisition prior to working capital and future income tax liability assumed on acquisition.
(8) Total assets and total liabilities have been restated for the retroactive application of change in accounting policy for asset retirement obligations.
(9) Includes other revenue.

CONSOLIDATED BALANCE SHEETS

As at September 30 and December 31 (unaudited)

($CDN thousands)	2005	2004
ASSETS		
Current assets		
Cash and cash equivalents	**$ 4,664**	$ 4,413
Accounts receivable	**106,809**	72,881
Prepaid expenses	**14,992**	9,878
Commodity and foreign currency contracts (Note 6)	**7,556**	22,294
	134,021	109,466
Reclamation fund	**23,262**	21,294
Property, plant and equipment	**2,168,665**	2,016,646
Goodwill	**157,592**	157,592
Total assets	**$ 2,483,540**	$ 2,304,998
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**$ 136,037**	$ 103,572
Cash distributions payable	**32,174**	27,893
Current portion of long-term debt (Note 4)	**8,128**	8,715
Commodity and foreign currency contracts (Note 6)	**39,724**	26,336
	216,063	166,516
Long-term debt (Note 4)	**307,686**	211,834
Other long-term liabilities (Note 5)	**6,239**	3,893
Asset retirement obligations (Note 7)	**81,494**	73,001
Future income taxes (Note 8)	**300,678**	300,406
Total liabilities	**912,160**	755,650
NON-CONTROLLING INTEREST		
Exchangeable shares (Note 9)	**36,502**	35,967
UNITHOLDERS' EQUITY		
Unitholders' capital (Note 10)	**1,983,333**	1,926,351
Contributed surplus (Note 11)	**5,424**	6,475
Accumulated earnings	**1,105,268**	878,807
Accumulated cash distributions (Note 13)	**(1,559,147)**	(1,298,252)
Total unitholders' equity	**1,534,878**	1,513,381
Total liabilities and unitholders' equity	**$ 2,483,540**	$ 2,304,998

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF INCOME AND ACCUMULATED EARNINGS

For the three and nine months ended September 30 (unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
($CDN thousands, except per unit amounts)	**2005**	2004	**2005**	2004
		Restated (Note 2)		Restated (Note 2)
Revenue				
Oil, natural gas, natural gas liquids and sulphur sales	**310,249**	230,769	**799,899**	669,670
Royalties	**(65,325)**	(47,320)	**(161,807)**	(131,790)
	244,924	183,449	**638,092**	537,880
Realized loss on commodity and foreign currency contracts (Note 6)	**(26,578)**	(24,183)	**(61,124)**	(55,711)
Unrealized gain (loss) on commodity and foreign currency contracts (Note 6)	**12,247**	(28,987)	**(28,126)**	(59,154)
	230,593	130,279	**548,842**	423,015
Expenses				
Transportation	**3,391**	3,563	**10,758**	11,002
Operating	**36,171**	36,029	**103,284**	104,709
General and administrative - cash	**6,382**	4,928	**19,895**	15,213
General and administrative - non-cash (Notes 11 and 12)	**3,638**	4,162	**7,526**	8,217
Interest on long-term debt	**4,461**	2,944	**10,935**	10,335
Depletion, depreciation and accretion	**65,797**	58,839	**190,824**	177,170
Gain on foreign exchange	**(11,921)**	(14,406)	**(7,813)**	(9,354)
	107,919	96,059	**335,409**	317,292
Income before taxes	**122,674**	34,220	**213,433**	105,723
Capital taxes	**(606)**	(683)	**(1,593)**	(2,083)
Future income tax (expense) recovery (Note 8)	**(5,700)**	6,000	**18,200**	27,200
Net income before non-controlling interest	**116,368**	39,537	**230,040**	130,840
Non-controlling interest (Note 9)	**(1,768)**	(640)	**(3,579)**	(2,145)
Net income	**114,600**	38,897	**226,461**	128,695
Accumulated earnings, beginning of period	**990,668**	738,102	**878,807**	648,304
Accumulated earnings, end of period	**1,105,268**	776,999	**1,105,268**	776,999
Net income per unit (Note 14)				
Basic	**0.61**	0.21	**1.21**	0.71
Diluted	**0.59**	0.21	**1.18**	0.69

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

For the three and nine months ended September 30 (unaudited)

($CDN thousands)	Three Months Ended September 30 2005	Three Months Ended September 30 2004	Nine Months Ended September 30 2005	Nine Months Ended September 30 2004
		Restated (Note 2)		Restated (Note 2)
CASH FLOW FROM OPERATING ACTIVITIES				
Net income	**114,600**	38,897	**226,461**	128,695
Add items not involving cash				
Non-controlling interest	**1,768**	640	**3,579**	2,145
Future income tax expense (recovery)	**5,700**	(6,000)	**(18,200)**	(27,200)
Depletion, depreciation and accretion	**65,797**	58,839	**190,824**	177,170
Non-cash (gain) loss on commodity and foreign currency contracts (Note 6)	**(12,247)**	28,128	**28,126**	50,300
Unrealized gain on foreign exchange	**(11,939)**	(14,690)	**(7,940)**	(7,083)
Amortization of commodity and foreign currency contracts	**-**	859	**-**	8,854
Non-cash trust unit incentive compensation (Notes 11 and 12)	**4,438**	4,162	**9,041**	8,217
Funds from operations	**168,117**	110,835	**431,891**	341,098
Expenditures on site restoration and reclamation	**(946)**	-	**(3,035)**	-
Change in non-cash working capital	**(54,395)**	(110,055)	**(59,428)**	(31,301)
	112,776	780	**369,428**	309,797
CASH FLOW FROM FINANCING ACTIVITIES				
Issuance of long-term debt, net of repayment	**8,007**	1,035	**103,170**	15,704
Issue of trust units	**2,123**	4,361	**17,024**	18,000
Trust unit issue costs	**(8)**	(4)	**(21)**	(20)
Cash distributions paid	**(76,898)**	(76,870)	**(225,610)**	(225,233)
Payment of retention bonus	**(1,000)**	(1,000)	**(1,000)**	(1,000)
Change in non-cash working capital	**1,783**	71,370	**1,820**	3,442
	(65,993)	(1,108)	**(104,617)**	(189,107)
CASH FLOW FROM INVESTING ACTIVITIES				
Corporate acquisition, net of cash received (Note 3)	**-**	-	**(42,182)**	(60)
Acquisition of petroleum and natural gas properties	**(22,846)**	2,105	**(108,215)**	(404)
Proceeds on disposition of petroleum and natural gas properties	**16,985**	3,240	**19,965**	57,587
Capital expenditures	**(83,047)**	(45,979)	**(180,638)**	(146,630)
Net reclamation fund contributions	**(983)**	(1,888)	**(1,969)**	(5,417)
Changes in non-cash working capital	**47,772**	40,019	**48,479**	34,169
	(42,119)	(2,503)	**(264,560)**	(60,755)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**4,664**	(2,831)	**251**	59,935
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	**-**	75,061	**4,413**	12,295
CASH AND CASH EQUIVALENTS, END OF PERIOD	**4,664**	72,230	**4,664**	72,230

See accompanying notes to consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

September 30, 2005 and 2004 (unaudited)

(all tabular amounts in thousands, except per unit and volume amounts)

1. SUMMARY OF ACCOUNTING POLICIES

The unaudited interim consolidated financial statements follow the same accounting policies as the most recent annual audited financial statements. The interim consolidated financial statement note disclosures do not include all of those required by Canadian generally accepted accounting principles ("GAAP") applicable for annual financial statements. Accordingly, these interim financial statements should be read in conjunction with the audited consolidated financial statements included in the Trust's 2004 Annual Report.

2. RESTATEMENT OF PRIOR PERIODS DUE TO CHANGES IN ACCOUNTING POLICIES

As at December 31, 2004, the Trust adopted the following new accounting policy that required restatement of prior periods. The following explains the impact of this restatement on the Trust's previously reported financial statements for the third quarter of 2004.

Exchangeable Securities – Non-Controlling Interest

On January 19, 2005 the CICA issued EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" which requires that exchangeable securities issued by a subsidiary of an income trust be reflected as either non-controlling interest or debt, as appropriate, in the consolidated balance sheet unless they meet certain criteria. EIC-151 states that if the exchangeable shares are transferable to a third party, they should be reflected as non-controlling interest or debt, as appropriate. The exchangeable shares issued by ARL, a corporate subsidiary of the Trust, are publicly traded and therefore must be recorded as non-controlling interest outside of Unitholders' equity. Previously, the exchangeable shares were reflected as a component of Unitholders' equity.

In accordance with the transitional provisions of EIC-151, retroactive application has been applied with restatement of prior periods. As a result of this change in accounting policy, the Trust has reflected non-controlling interest of $36.5 million and $36 million, respectively, in the Trust's consolidated balance sheet as at September 30, 2005 and December 31, 2004. Consolidated net income has been reduced for net income attributable to the non-controlling interest of $3.6 million and $2.1 million, respectively, for the first nine months of 2005 and 2004. Opening accumulated earnings for 2004 were decreased by $11.2 million for the cumulative net income attributable to the non-controlling interest, Unitholders' equity was reduced by $25.1 million and non-controlling interest on the consolidated balance sheet increased by $36.3 million. The new accounting policy resulted in a change in the calculation of weighted average trust units. Previously, weighted average trust units included outstanding exchangeable shares at the period end exchange ratio whereas under the new accounting policy, the weighted average trust units excludes trust units issuable for exchangeable shares. There was no change to net income per basic trust unit as a result of this change in accounting policy.

3. ACQUISITION OF 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 was paid as follows:

Net Assets Acquired		
Working capital deficit	$	(1,359)
Property, plant and equipment		62,456
Asset retirement obligation		(443)
Future income taxes		(18,472)
Total net assets acquired	**$**	**42,182**
Consideration Paid		
Cash and fees paid	$	42,182
Total consideration paid	**$**	**42,182**

Pursuant to EIC-124, the acquisition of Romulus did not meet the necessary criteria in order to be classified as a business. Therefore, the acquisition has been accounted for as an asset acquisition.

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.

4. LONG-TERM DEBT

	September 30, 2005	December 31, 2004
Revolving credit facilities		
Working capital facility	**$ 103,331**	$ 290
Senior secured notes		
8.05% USD Note	**32,511**	33,701
4.94% USD Note	**34,834**	36,108
4.62% USD Note	**72,569**	75,225
5.10% USD Note	**72,569**	75,225
Total debt outstanding	**$ 315,814**	$ 220,549
Current portion of debt	**8,128**	8,715
Long-term debt	**$ 307,686**	$ 211,834

5. OTHER LONG-TERM LIABILITIES

	September 30, 2005	December 31, 2004
Retention bonuses	**$ 1,000**	$ 2,000
Accrued long-term incentive compensation	**5,239**	1,893
Total other long-term liabilities	**$ 6,239**	$ 3,893

The retention bonuses arose upon internalization of the management contract in 2002. The long-term portion of retention bonuses will be paid in August 2007.

The accrued long-term incentive compensation represents the long-term portion of the Trust's estimated liability for the Whole Trust Unit Incentive Plan as at September 30, 2005 (see Note 12). This amount is payable in 2007 through 2008.

6. FINANCIAL INSTRUMENTS

The Trust uses a variety of derivative instruments to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. The Trust considers all of these transactions to be effective economic hedges, however, the majority of the Trust's contracts do not qualify as effective hedges for accounting purposes.

Following is a summary of all derivative contracts in place as at September 30, 2005:

Financial WTI Crude Oil Contracts

Term	Contract	Volume bbl/d	Swap US$/bbl	Bought Put US$/bbl	Sold Put US$/bbl	Sold Call US$/bbl
2005						
Oct 05 – Oct 05	3 Way	2,000	-	47.32	29.00	72.00
Oct 05 – Dec 05	3 Way	500	-	34.00	30.00	41.75
Oct 05 – Dec 05	Put Spread	2,000	-	47.05	29.00	-
Oct 05 – Dec 05	Put Spread	1,000	-	46.65	33.00	-
Oct 05 – Dec 05	Put Spread	3,500	-	46.36	30.00	-
Oct 05 – Dec 05	Swap	4,000	28.95	-	-	-
Nov 05 – Dec 05	Put Spread	2,000	-	47.32	29.00	-
2005 Weighted Average		**13,000**	**28.95**	**46.07**	**29.89**	**59.12**
2006						
Jan 06 – Mar 06	Bought Put	2,000	-	50.00	-	-
Jan 06 – Mar 06	Bought Put	1,000	-	50.00	-	-
Jan 06 – Mar 06	Put Spread	1,000	-	55.00	45.00	-
Jan 06 – June 06	Put Spread	2,000	-	50.00	40.00	-
Jan 06 – Dec 06	Put Spread	1,000	-	55.00	45.00	-
Jan 06 – Dec 06	Bought Put	1,000	-	55.00	-	-
Apr 06 – Dec 06	Bought Put	2,000	-	50.00	-	-
Apr 06 – Dec 06	Put Spread	2,000	-	55.00	45.00	-
2006 Weighted Average		**6,992**	**-**	**52.68**	**43.68**	**-**

Financial AECO Natural Gas Contracts

Term	Contract	Volume GJ/d	Swap CDN$/GJ	Bought Put CDN$/GJ	Sold Put CDN$/GJ	Sold Call CDN$/GJ
2005						
Oct 05 – Oct 05	3 Way	10,000	-	6.00	5.00	8.00
Oct 05 – Oct 05	3 Way	5,000		6.50	5.50	7.55
Oct 05 – Oct 05	3 Way	5,000	-	6.50	5.50	8.00
Oct 05 – Oct 05	3 Way	10,000	-	6.65	6.25	10.00
Oct 05 – Oct 05	3 Way	10,000	-	6.63	6.25	9.50
Oct 05 – Oct 05	Collar	10,000	-	6.42	-	8.00
Oct 05 – Oct 05	Collar	10,000	-	6.65	-	8.00
Oct 05 – Oct 05	Bought Put	5,000	-	6.75	-	-
Oct 05 – Oct 05	Bought Put	10,000	-	6.85	-	-
Oct 05 – Oct 05	Bought Put	10,000	-	6.99	-	-
Oct 05 – Oct 05	Bought Put	10,000	-	7.42	-	-
Nov 05 – Dec 05	Bought Put	10,000	-	8.00	-	-
Nov 05 – Dec 05	Put Spread	10,000	-	8.00	6.00	-
2005 Weighted Average		**45,272**		**7.07**	**5.83**	**8.55**
2006						
Jan 06 – Mar 06	Bought Put	10,000	-	8.00	-	-
Jan 06 – Mar 06	Put Spread	10,000	-	8.00	6.00	-
Jan 06 – Mar 06	Put Spread	10,000	-	9.00	7.00	-
Apr 06 – Oct 06	Put Spread	10,000	-	7.50	5.50	-
Apr 06 – Oct 06	Put Spread	10,000	-	7.50	5.50	-
2006 Weighted Average		**19,123**	**-**	**7.82**	**5.80**	**-**

Financial Natural Gas NYMEX Contracts

Term	Contract	Volume mmbtu/d	Swap US$/mmbtu	Bought Put US$/mmbtu	Sold Put US$/mmbtu	Sold Call US$/mmbtu
2005						
Oct 05 – Oct 05	Collar	20,000	-	6.50	-	8.00
Nov 05 – Dec 05	Bought Put	10,000	-	8.00	-	-
2005 Weighted Average		**13,370**	**-**	**7.24**	**-**	**8.00**
2006						
Jan 06 – Mar 06	Bought Put	10,000	-	8.00	-	-
2006 Weighted Average		**2,466**	**-**	**8.00**	**-**	**-**

Financial Natural Gas AECO Basis Contracts

Term	Contract	Volume mmbtu/d	Swap US$/mmbtu
2005			
Oct 05 – Oct 05	Swap	10,000	(0.865)
Oct 05 – Oct 05	Swap	10,000	(0.840)
2005 Weighted Average		**6,739**	**(0.853)**

Financial Foreign Currency Contracts

Term	Contract	Volume MM US$	Swap CDN$/US$	Swap US$/CDN$
USD Sales Contracts				
2005				
Oct 05 – Oct 05	Swap	4.0	1.2384	0.8075
Oct 05 – Dec 05	Swap	10.7	1.2000	0.8333
Oct 05 – Dec 05	Swap	13.5	1.2115	0.8254
Oct 05 – Dec 05	Swap	8.9	1.2153	0.8228
Oct 05 – Dec 05	Swap	7.1	1.2169	0.8218
Total and 2005 Weighted Average		**44.2**	**1.2128**	**0.8245**
2006				
Jan 06 – Jun 06	Swap	6.5	1.2000	0.8333
Jan 06 – Jun 06	Swap	6.5	1.2115	0.8254
Jan 06 – Jun 06	Swap	9.0	1.2240	0.8170
Jan 06 – Jun 06	Swap	15.1	1.2395	0.8068
Total and 2006 Weighted Average		**37.1**	**1.2239**	**0.8171**
USD Purchase Contracts				
2005				
Oct 05 – Dec 05	Swap	4.0	1.1966	0.8357
Total and 2005 Weighted Average		**4.0**	**1.1966**	**0.8357**
2006				
Sep 06 – Dec 06	Swap	7.5	1.1682	0.8560
Sep 06 – Dec 06	Swap	7.5	1.1687	0.8557
Total and 2006 Weighted Average		**15.0**	**1.1685**	**0.8558**

Financial Electricity Contracts[1]

Term	Contract	Volume MWh	Swap CDN$/MWh
Oct 05 – Dec 10	Swap	5.0	63.00

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

Financial Interest Rate Contracts [1]

Term	Contract	Principal MM US$	Fixed Annual Rate (%)	Spread on 3 Mo. LIBOR
Oct 05 – Apr 14	Swap	30.5	4.62	38.5bps

(1) Interest rate swap contract has an optional termination date of April 27, 2009. The Trust has the option to extend the optional termination date by one year on the anniversary of the trade date each year until April 2009. Starting in 2009, the contract amount 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 contract as an effective accounting hedge as at January 1, 2004. A realized loss of $0.3 million for the first nine months of 2005 on the electricity contract has been included in operating costs. The fair value unrealized loss on the electricity contract of $0.4 million has not been recorded on the consolidated balance sheet at September 30, 2005.

Previously the Trust had entered into two interest rate swap contracts to manage the Company's interest rate exposure on debt instruments. These contracts were designated as effective accounting hedges on the contract date. During the quarter one of these contracts was unwound at a nominal cost . A realized gain of $0.7 million for the first nine months of 2005 on the interest rate swap contracts has been included in interest expense. The fair value unrealized loss on the remaining interest rate swap contract of $0.7 million has not been recorded on the consolidated balance sheet at September 30, 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 for 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:

	September 30, 2005	September 30, 2004
Fair value, beginning of period [1]	**$ (4,042)**	$ (14,575)
Fair value, end of period [1]	**(32,168)**	(64,875)
Change in fair value of contracts in the period	**(28,126)**	(50,300)
Realized losses in the period	**(61,124)**	(55,711)
Amortization of crystallized hedging gains	**-**	4,526
Amortization of opening mark to market loss	**-**	(13,380)
Loss on commodity and foreign currency contracts [1]	**$ (89,250)**	$ (114,865)

	September 30, 2005	December 31, 2004
Commodity and foreign currency contracts liability	**$ (39,724)**	$ (26,336)
Commodity and foreign currency contracts asset	**$ 7,556**	$ 22,294

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

At September 30, 2005, the fair value of contracts not designated as accounting hedges was a liability of $32.2 million. The Trust recorded a loss on commodity and foreign currency contracts of $89.3 million and $114.9 million in the statement of income for the first nine months of 2005 and 2004, respectively. This amount includes the realized and unrealized gains and losses on derivative contracts that do not qualify as effective accounting hedges.

7. ASSET RETIREMENT OBLIGATIONS

The following table reconciles the movement in the Asset Retirement Obligation balance:

	September 30, 2005	December 31, 2004
Balance, beginning of period	**$ 73,001**	$ 66,657
Increase in liabilities in the period	**7,668**	4,996
Liabilities settled in the period	**(3,035)**	(3,232)
Accretion expense	**3,860**	4,580
Balance, end of period	**$ 81,494**	$ 73,001

8. INCOME TAXES

The future income tax expense of $5.7 million in the third quarter of 2005 included an expense of $4.2 million due to the unrealized gain of $12.2 million on commodity and foreign currency contracts. In the third quarter of 2004, the future income tax recovery of $6 million included a recovery of $10 million for the $29 million unrealized loss on commodity and foreign currency contracts. For the first nine months of 2005, the Trust recorded a future income tax recovery of $18.2 million which included a recovery of $9.7 million due to the unrealized loss of $28.1 million on commodity and foreign currency contracts.

The Trust's future tax rate applicable to temporary differences currently approximates 34 per cent.

9. EXCHANGEABLE SHARES

ARL EXCHANGEABLE SHARES	**September 30, 2005**	September 30, 2004
Balance at beginning of period	**1,784**	2,011
Exchanged for trust units [1]	**(147)**	(197)
Balance, end of period	**1,637**	1,814
Exchange ratio, end of period	**1.79533**	1.62818
Trust units issuable upon conversion, end of period	**2,939**	2,954

(1) During the first nine months of 2005, 146,479 ARL exchangeable shares were converted to trust units at an average exchange ratio of 1.74105.

Following is a summary of the non-controlling interest for September 30, 2005 and December 31, 2004:

	September 30, 2005	December 31, 2004
Non-controlling interest, beginning of period	**$ 35,967**	$ 36,311
Reduction of book value for conversion to trust units	**(3,044)**	(4,295)
Current period net income attributable to non-controlling interest	**3,579**	3,951
Non-controlling interest, end of period	**$ 36,502**	$ 35,967
Accumulated earnings attributable to non-controlling interest	**$ 18,718**	$ 15,139

10. UNITHOLDERS' CAPITAL

	September 30, 2005		December 31, 2004	
TRUST UNITS ISSUED	**Number of Trust Units**	**$**	Number of Trust Units	$
Balance, beginning of period	**185,822**	**1,926,351**	179,780	1,843,112
Issued for properties	**-**	**-**	2,032	30,500
Issued on conversion of ARL exchangeable shares (Note 9)	**255**	**3,044**	363	4,295
Issued on exercise of employee rights (Note 11)	**1,347**	**21,456**	1,751	20,672
Distribution reinvestment program	**1,729**	**32,503**	1,896	27,924
Trust unit issue costs	**-**	**(21)**	-	(152)
Balance, end of period	**189,153**	**1,983,333**	185,822	1,926,351

11. TRUST UNIT INCENTIVE RIGHTS PLAN

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

	Number of Rights	**Average Exercise Price ($)**
Balance, beginning of period	**3,009**	**10.92**
Exercised	**(1,347)**	**11.50**
Cancelled	**(157)**	**11.11**
Balance before reduction of exercise price	**1,505**	**11.12** [1]
Reduction of exercise price	**-**	**(0.57)**
Balance, end of period	**1,505**	**10.55** [1]

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

The Trust recorded compensation expense of $4.9 million and $6.7 million for the first nine months of 2005 and 2004 respectively for the cost associated with the rights. The compensation expense was based on the fair value of rights issued after January 1, 2003 which were outstanding in the first quarter of 2005 and is amortized over the remaining vesting period of such rights. Of the 3,013,569 rights issued on or after January 1, 2003 that were subject to recording compensation expense, 353,499 rights have been cancelled and 1,360,875 rights have been exercised to September 30, 2005.

The following table reconciles the movement in the contributed surplus balance:

CONTRIBUTED SURPLUS	**September 30, 2005**	December 31, 2004
Balance, beginning of period	**$ 6,475**	$ 3,471
Compensation expense	**4,881**	5,171
Net benefit on rights exercised [1]	**(5,932)**	(2,167)
Balance, end of period	**$ 5,424**	$ 6,475

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

12. WHOLE TRUST UNIT INCENTIVE PLAN

For the nine months ended September 30, 2005, the Trust recorded a change in compensation liability relating to the Whole Trust Unit Incentive Plan of $4.6 million (2004 – $1.5 million). The compensation liability was based on the September 30, 2005 trust unit closing price of $24.10 and management's estimate of the number of Restricted Trust Units ("RTU") and Performance Trust Units ("PTU") to be issued on maturity. The following table summarizes the RTU and PTU movement for the nine months ended September 30, 2005.

	Number of RTU's	Number of PTU's
Balance, beginning of period	224	128
Granted	232	219
Exercised	(78)	-
Forfeited	(35)	(39)
Balance, end of period	343	308

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

	September 30, 2005	December 31, 2004
Balance, beginning of period	**$ 2,915**	$ -
Increase in liabilities in the period (net of cash payments)	**4,575**	2,915
Balance, end of period	**$ 7,490**	$ 2,915
Current portion of liability	**2,251**	1,022
Long-term liability	**$ 5,239**	$ 1,893

13. RECONCILIATION OF CASH FLOW AND DISTRIBUTIONS

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	**2005**	2004
Funds from operations before changes in non-cash working capital	**168,117**	110,835	**431,891**	341,098
Add (deduct):				
Cash withheld to fund capital expenditures	**(73,841)**	(26,156)	**(162,024)**	(85,406)
Reclamation fund contributions and interest earned on fund	**(1,717)**	(1,501)	**(5,112)**	(5,020)
Discretionary debt repayments	**-**	-	**(3,860)**	(4,225)
Cash distributions [2]	**92,559**	83,178	**260,895**	246,447
Accumulated cash distributions, beginning of period	**1,466,588**	1,131,544	**1,298,252**	968,275
Accumulated cash distributions, end of period	**1,559,147**	1,214,722	**1,559,147**	1,214,722
Cash distributions per unit [1]	**0.49**	0.45	**1.39**	1.35
Accumulated cash distributions per unit, beginning of period	**15.14**	13.34	**14.24**	12.44
Accumulated cash distributions per unit, end of period	**15.63**	13.79	**15.63**	13.79

(1) Cash distributions per trust unit reflect the sum of the per trust unit amounts declared monthly to unitholders.
(2) Cash distributions include non-cash amounts relating to the distribution reinvestment program.

14. BASIC AND DILUTED PER TRUST UNIT CALCULATIONS

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004[4]	**2005**	2004[4]
Weighted average units[1]	**188,770**	184,675	**187,470**	182,311
Trust units issuable on conversion of exchangeable shares[2]	**2,939**	2,954	**2,939**	2,954
Dilutive impact of rights[3]	**1,022**	1,261	**1,553**	1,883
Diluted trust units	**192,731**	188,890	**191,962**	187,148

(1) Weighted average trust units excludes 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 none have been excluded in the diluted trust unit calculation.
(4) 2004 weighted average trust units have been restated to exclude trust units issuable for exchangeable shares in accordance with retroactive change in accounting policy for non-controlling interest.

15. COMMITMENTS AND CONTINGENCIES

Following is a summary of the Trust's contractual obligations and commitments due by period as at September 30, 2005:

($ millions)	2005	2006-2007	2008-2009	Thereafter	Total
Debt repayments [1]	8.1	133.5	34.1	140.1	315.8
Operating leases	1.2	7.8	7.1	3.6	19.7
Purchase commitments	2.7	4.8	4.6	9.2	21.3
Retention bonuses	-	2.0	-	-	2.0
Derivative contract premiums [2]	7.5	11.3	-	-	18.8
Total contractual obligations	19.5	159.4	45.8	152.9	377.6

(1) Includes long-term and short-term debt.
(2) Fixed premiums to be paid in future periods on certain commodity derivative contracts.

In addition to the above, the Trust has commitments related to its risk management program (See Note 6).

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.

16. RECLASSIFICATION

Certain information provided for prior years has been reclassified to conform to the presentation applied in 2005.

CORPORATE AND UNITHOLDER INFORMATION

DIRECTORS

Mac H. Van Wielingen (1) (3) (4)
Chairman

Walter DeBoni (1) (4) (5)
Vice-Chairman

John P. Dielwart
President and Chief Executive Officer

Frederic C. Coles (2) (3) (5)

Fred J. Dyment (1) (2)

Michael M. Kanovsky (1) (2)

John M. Stewart (3) (4) (5)

(1) **Member of Audit Committee**
(2) **Member of Reserve Audit Committee**
(3) **Member of Human Resources and Compensation Committee**
(4) **Member of Policy and Board Governance Committee**
(5) **Health, Safety and Environment Committee**

OFFICERS

John P. Dielwart
President and Chief Executive Officer

Doug J. Bonner
Vice-President, Engineering

David P. Carey
Vice-President, Business Development

Susan D. Healy
Vice-President, Corporate Services

Steven W. Sinclair
Vice-President, Finance and Chief Financial Officer

Myron M. Stadnyk
Vice-President, Land and Operations

P. Van R. Dafoe
Treasurer

Allan R. Twa
Corporate Secretary

EXECUTIVE OFFICE

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LEGAL COUNSEL

Burnet Duckworth & Palmer LLP
Calgary, Alberta

Canada's Climate Change Voluntary Challenge and Registry. The industry's voluntary effort to reduce greenhouse gas emissions and document the efforts year over year.

CORPORATE CALENDAR

2006

February 8	2005 Year End Results
February 15	Announcement of Q1 Distribution Monthly Amounts

STOCK EXCHANGE LISTING

The Toronto Stock Exchange

Trading Symbols:
AET.UN **(Trust Units)**
ARX **(Exchangeable Shares)**

INVESTOR INFORMATION

Visit our website at
www.arcresources.com
or www.arcenergytrust.com
or contact:
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(403) 503-8600 or
1-888-272-4900 (Toll Free)

PRIVACY OFFICER

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Members commit to continuous improvement in the responsible management, development and use of our natural resources; protection of our environment; and, the health and safety of our workers and the general public