ARC ENERGY TRUST

Second Quarter Interim Report 2

For The Three Months Ended June 30, 2005

	Three Months Ended June 30		Six Months Ended June 30	
	2005	2004	**2005**	2004
FINANCIAL				
($CDN thousands, except per unit and per boe amounts)				
Revenue before royalties	**251,596**	233,307	**489,650**	438,901
Per unit [8]	**1.32**	1.26	**2.58**	2.38
Per boe	**50.40**	44.09	**49.07**	41.86
Cash flow [3]	**121,808**	122,249	**263,774**	230,263
Per unit [8]	**0.64**	0.66	**1.39**	1.25
Per boe	**24.40**	23.10	**26.43**	21.96
Net income [5]	**73,215**	50,338	**111,861**	89,798
Per unit [1] [5]	**0.39**	0.28	**0.60**	0.50
Cash distributions	**84,468**	82,054	**168,335**	163,269
Per unit [1]	**0.45**	0.45	**0.90**	0.90
Payout ratio [6]	**69**	67	**64**	71
Net debt outstanding [4]	**366,216**	220,074	**366,216**	220,074
OPERATING				
Production				
Crude oil (bbl/d)	**22,046**	22,720	**22,020**	23,191
Natural gas (mcf/d)	**173,116**	186,681	**174,586**	180,607
Natural gas liquids (bbl/d)	**3,962**	4,313	**4,016**	4,318
Total (boe/d)	**54,860**	58,147	**55,133**	57,611
Average prices [5]				
Crude oil ($/bbl)	**58.37**	47.43	**56.02**	43.85
Natural gas ($/mcf)	**7.42**	6.99	**7.31**	6.83
Natural gas liquids ($/bbl)	**46.13**	38.22	**46.35**	35.26
Oil equivalent ($/boe) [7]	**50.40**	44.09	**49.06**	41.86
Operating netback ($/boe)				
Commodity and other revenue (before hedging)	**50.40**	44.09	**49.06**	41.86
Transportation costs	**(0.76)**	(0.68)	**(0.74)**	(0.71)
Royalties	**(10.34)**	(8.64)	**(9.67)**	(8.06)
Operating costs	**(7.35)**	(6.64)	**(6.73)**	(6.55)
Netback (before hedging)	**31.95**	28.13	**31.92**	26.54
TRUST UNITS				
(thousands)				
Units outstanding, end of period	**188,402**	184,247	**188,402**	184,247
Units issuable for exchangeable shares	**2,927**	3,049	**2,927**	3,049
Total units outstanding and issuable for exchangeable shares, end of period	**191,329**	187,296	**191,329**	187,296
Weighted average units [2]	**187,388**	181,949	**186,810**	181,118
TRUST UNIT TRADING STATISTICS				
($CDN, except volumes) based on intra-day trading				
High	**20.30**	15.74	**20.40**	15.74
Low	**16.88**	14.28	**16.55**	13.50
Close	**19.94**	15.35	**19.94**	15.35
Average daily volume	**604,981**	336,965	**685,964**	420,668

(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

With continuing high commodity prices, ARC realized positive results in the second quarter of 2005 in all aspects of our business although cash hedge losses of $27 million (including cost to collapse 2006 collared contracts) muted financial results somewhat. Investors' confidence that a higher oil price is here to stay for some time is reflected in ARC's unit price that has been trading at all time highs. ARC's unit price reached a high of $20.30 during the second quarter and has recently traded over $22.00 per unit.

The second quarter WTI price averaged US$53.13 per barrel and natural gas averaged $7.38 per mcf AECO. ARC continues to protect its distribution stability by hedging some of its production with a hedging strategy that focuses on purchasing puts (floor prices). This hedging method allows ARC to participate in the up-side of higher commodity prices but still limiting downside exposure. Several contracts with price caps remain in place for the balance of 2005 which account for the majority of hedge losses being incurred. ARC took the opportunity to collapse two three-way hedge contracts at a cost of $6.1 million during the quarter that capped ARC's price at approximately $40.00 per barrel on 2,000 barrels per day for the first half of 2006. ARC's 2006 production is now exposed to full price upside.

ARC completed several strategic acquisitions within two of its core areas during the second quarter of 2005. In total, ARC purchased 6 mmboe of proved and 9 mmboe of proved plus probable reserves (91 per cent liquids) for a total consideration of $124 million. Current production from these properties is approximately 2,100 boe/d. Approximately 270 boe/d of the acquired production is reflected in second quarter results; full benefit of the production will be realized in the third quarter of 2005. Although the acquisitions are not material relative to the size of ARC, they are of a strategic nature and increase working interest in areas where ARC already operates. ARC continues to concentrate on these types of acquisitions, which allow it to consolidate its interests in high-quality properties and add additional land adjacent to existing key properties. ARC's technical staff know these properties well and are confident that ARC can extract incremental value from them. The acquisitions were funded through ARC's existing lines of credit and have increased ARC's debt to cash flow to 0.7 times annualized first half cash flow. At this level, ARC's debt to cash flow remains significantly below the average for the sector. The acquisition market continues to be very competitive and expensive. While we will continue to aggressively pursue strategic acquisition opportunities, ARC is in the strong position of being able to maintain production through internal drilling opportunities that provide a superior internal rate of return for ARC's unitholders.

ARC's production was slightly lower at 54,860 boe/d in the second quarter of 2005 compared to 58,147 in the second quarter of 2004 due primarily to property dispositions which occurred in the second quarter of 2004 totaling 1,800 boe/d. ARC was very active during the quarter with drilling and development activities and with help from high commodity prices, realized cash flows of $122 million for the quarter net of hedge losses and a one-time payment of $6.1 million to collapse certain 2006 hedges. ARC paid out 69 per cent of cash flow (66 per cent before one-time hedge payment) to its unitholders and utilized the remaining 31 per cent to fund 77 per cent of its capital development program for the quarter and to make contributions to the reclamation fund. ARC expects average production for full year 2005 to be 56,000 boe/d. Upon completion of our annual mid-year forecast update, the Board of Directors has approved an increase in distributions from $0.15 per unit to $0.17 per unit effective with the September 15 payment. ARC expects to maintain that level of distribution with production of between 55,000 boe/d to 60,000 boe/d at an average WTI price of US$50.00 per barrel for oil and $7.00 per GJ for AECO natural gas. ARC will continue to focus on executing its development program for the remainder of 2005 and exploit opportunities on its existing properties.

It is with much regret and sadness that ARC lost an important member of its Board of Directors. Mr. John Beddome passed away on May 10, 2005. He was a member of ARC's board since inception and has contributed his wealth of knowledge and experience in the oil and gas industry to ARC and to his community at large. His involvement with ARC's board will be missed. On behalf of the Board of Directors and all employees at ARC, I wish to extend our condolences to Mr. Beddome's family.

John P. Dielwart
Director, President and
Chief Executive Officer

ACCOMPLISHMENTS / FINANCIAL UPDATE

- Production averaged 54,860 boe per day in the second quarter of 2005, six per cent lower than the 58,147 boe per day production in the second quarter of 2004, due in part to the disposition of non-core properties with production of 1,800 boe/d in 2004. The Trust was very active in the second quarter, spending $45.1 million on capital development activities and $124 million on acquisition of properties within the Trust's core operating areas.
- As part of this report, the Trust has issued new guidance for 2005 that includes an increase in forecast full year production volumes to 56,000 boepd.
- ARC realized cash flow of $122 million ($0.64 per trust unit) in the second quarter of 2005, the same as in the second quarter of 2004 ($0.66 per trust unit). Cash flow was maintained through strong commodity prices on slightly lower production volume and after a one-time payment of $6.1 million to collapse certain 2006 hedges.
- West Texas Intermediate ("WTI") averaged US$53.13 per barrel during the second quarter (six per cent higher than the first quarter 2005) while the second quarter AECO natural gas price averaged $7.38 per mcf (10 per cent higher than the first quarter 2005).
- The Trust declared cash distributions of $84.5 million ($0.45 per trust unit) in the second quarter of 2005, resulting in a payout ratio of 69 per cent for the quarter (66 per cent before one-time hedge payment) and a 64 per cent payout ratio for the six months ended June 30, 2005.
- The Trust realized an operating netback, before hedging, of $31.95 per boe in the second quarter of 2005 compared to $28.13 per boe in the second quarter of 2004. The netback of $31.95 per boe represents the highest in the Trust's history. Operating costs of $7.35 per boe reflect traditional higher costs relating to second quarter maintenance activities. Year-to-date operating costs of $6.73 per boe are 2.8 per cent higher than the equivalent period in 2004.
- Despite debt financing $124 million in acquisitions in the second quarter, the Trust's balance sheet remains one of the strongest in the sector with debt at 0.6 times annualized first half 2005 pre-hedged cash flow (0.7 times after cash hedge losses).
- ARC's 2005 capital budget has been increased from $240 million to $270 million to take advantage of enhanced opportunities in our asset base and accommodate forecast capital in the recently acquired properties and to reflect increasing drilling and service industry costs.
- Cash distributions will increase from $0.15 per unit to $0.17 per unit effective with the September 15, 2005 distribution.

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 August 2, 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

(CDN$ millions, except per unit and volume data)	Three Months Ended June 30 2005	Three Months Ended June 30 2004	Six Months Ended June 30 2005	Six Months Ended June 30 2004
Cash flow from operations	**121.8**	122.2	**263.8**	230.3
Cash flow from operations per unit [3]	**0.64**	0.66	**1.39**	1.25
Net income	**73.2**	50.3	**111.9**	89.8
Distributions per unit	**0.45**	0.45	**0.90**	0.90
Payout ratio per cent [1]	**69**	67	**64**	71
Daily production (boe/d) [2]	**54,860**	58,147	**55,133**	57,611

(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

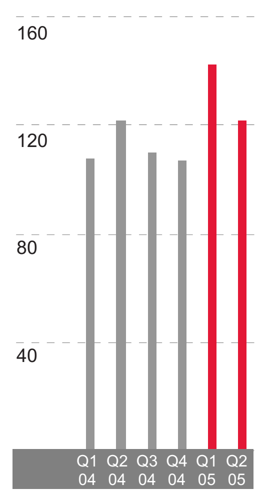
In the second quarter of 2005, net income increased by 46 per cent to $73.2 million from $50.3 million in the second quarter of 2004.

Cash Flow from Operations

Cash flow from operations remained relatively stable at $121.8 million during the second quarter 2005 compared to $122.2 in the second quarter of 2004 as a result of higher commodity prices that were offset by lower production due to property dispositions in 2004. For the first half of 2005, cash flow was $264 million, 15 per cent higher than first half 2004 cash flow. The increase was attributed to increased commodity prices that outweighed the decrease in production volumes and higher royalties (as a result of higher prices).

Cash flow in the second quarter of 2005 declined from first quarter cash flow primarily due to increased cash hedging losses of $19.9 million from $7.3 million to $27.2 million. In addition, higher seasonal operating costs in the quarter offset the impact of increased revenues net of royalties.

CASH FLOW
(CDN$ millions)



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

	$ millions	$per trust unit [3]	% Variance [2]
First half 2004 cash flow from operations	**$ 230.3**	**$ 1.25**	
Volume variance	(21.2)	(0.12)	(9)
Price variance	71.9	0.40	31
Change in cash losses on commodity and foreign currency contracts [1]	(3.0)	(0.02)	(1)
Royalties	(12.0)	(0.07)	(5)
Expenses:			
Transportation	0.1	-	
Operating	1.6	0.01	1
Cash G&A	(2.6)	(0.01)	(1)
Interest	0.9	0.01	-
Capital taxes	0.4	-	-
Realized foreign exchange gain (loss)	(2.7)	(0.01)	(1)
Other	0.1	-	-
Weighted average trust units plus units issuable for exchangeable shares at period end	-	(0.05)	
First half 2005 cash flow from operations	**$ 263.8**	**$ 1.39**	**15**

(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 averaged 54,860 boe/d in the second quarter of 2005 compared to 58,147 boe/d in the second quarter of 2004. The six per cent decrease in 2005 production resulted primarily from the impact of non-core property dispositions of 1,800 boe/d in the second quarter of 2004. The incremental production from the Trust’s capital development program in the first half of 2005 did not offset the natural production declines on existing properties as wet weather caused drilling to be delayed into the third quarter of 2005. As most of the second quarter acquisitions closed late in June, only production of 270 boe/d was recorded in the second quarter results and it is expected approximately 2,000 boe/d will be reflected in the third quarter results. 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 the timing of new wells coming on-stream.

Production [1]	Three Months Ended June 30 2005	2004	% Change	Six Months Ended June 30 2005	2004	% Change
Crude oil (bbl/d)	**22,046**	22,720	(3)	**22,020**	23,191	(5)
Natural gas (mcf/d)	**173,116**	186,681	(7)	**174,586**	180,607	(3)
NGL (bbl/d)	**3,962**	4,313	(8)	**4,016**	4,318	(7)
Total production (boe/d)	**54,860**	58,147	(6)	**55,133**	57,611	(4)
% Natural gas production	**53**	54		**53**	52%	
% Crude oil and liquids production	**47**	46		**47**	48%	

[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:

	Q2 2005				Q2 2004			
Core Areas [1]	**Total (boe/d)**	**Oil (bbls/d)**	**Gas (mmcf/d)**	**NGL (bbls/d)**	Total (boe/d)	Oil (bbls/d)	Gas (mmcf/d)	NGL (bbls/d)
Central AB	**7,881**	**1,311**	**29.3**	**1,683**	9,363	2,044	33.3	1,766
Northern AB & BC	**18,064**	**5,904**	**65.0**	**1,330**	20,436	5,772	78.7	1,549
Pembina	**7,422**	**3,705**	**17.5**	**800**	7,646	3,606	19.1	864
S.E. AB & S.W. Sask.	**11,426**	**1,486**	**59.6**	**10**	10,673	1,693	53.8	16
S.E. Sask.	**10,067**	**9,639**	**1.7**	**138**	10,029	9,605	1.8	118
Total	**54,860**	**22,045**	**173.1**	**3,961**	58,147	22,720	186.7	4,313

	YTD 2005				YTD 2004			
Core Areas [1]	**Total (boe/d)**	**Oil (bbls/d)**	**Gas (mmcf/d)**	**NGL (bbls/d)**	Total (boe/d)	Oil (bbls/d)	Gas (mmcf/d)	NGL (bbls/d)
Central AB	**8,191**	**1,410**	**30.2**	**1,741**	9,888	2,313	34.0	1,912
Northern AB & BC	**18,143**	**5,751**	**66.3**	**1,340**	19,425	5,726	73.3	1,478
Pembina	**7,306**	**3,641**	**17.3**	**783**	7,331	3,644	17.3	798
S.E. AB & S.W. Sask.	**11,344**	**1,499**	**59.0**	**14**	10,797	1,745	54.2	16
S.E. Sask.	**10,149**	**9,719**	**1.8**	**138**	10,170	9,763	1.8	114
Total	**55,133**	**22,020**	**174.6**	**4,016**	57,611	23,191	180.6	4,318

[1] Provincial references: AB is Alberta, BC is British Columbia, Sask. is Saskatchewan, S.E. is Southeast, S.W. is Southwest.

The Trust expects 2005 annual production to average approximately 56,000 boe/d. The 2005 production estimate incorporates incremental production from the Trust's planned capital program, which has been increased to $270 million from a previous forecast level of $240 million; and from the acquisitions completed in the second quarter of 2005.

Commodity Prices Prior to Hedging

	Three Months Ended June 30			Six Months Ended June 30		
Benchmark prices	**2005**	2004	% Change	**2005**	2004	% Change
AECO gas (CDN$/mcf) [(1)]	**7.38**	6.80	9	**7.04**	6.70	5
WTI oil (US$/bbl) [(2)]	**53.13**	38.34	39	**51.53**	36.75	40
CAD/USD foreign exchange rate	**1.24**	1.36	(9)	**1.24**	1.34	(7)
WTI oil (CDN$/bbl)	**66.10**	52.12	27	**63.65**	49.17	29

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

The differential between the Edmonton posted price and field price widened in the fourth quarter of 2004 and continued at relatively wide levels throughout the second quarter of 2005, which reduced ARC's realized oil price. The quality and transportation differential on the Trust's oil production was approximately $7.37 in the second quarter of 2005 compared to $5.54 in the second quarter of 2004. The widening differential was mainly due to an increase in heavy and medium grade sour crude types entering the North American market and a lack of incremental refining capacity to handle these grades of crude. Due to increased demand for heavier crude in the summer, the Trust expects a narrowing of differentials in the third quarter.

Prior to hedging activities, ARC realized $50.40 per boe in the second quarter of 2005, a 14 per cent increase over the $44.09 per boe received in 2004.

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

	Three Months Ended June 30			Six Months Ended June 30		
ARC Realized Prices [(1)]	**2005**	2004	% Change	**2005**	2004	% Change
Oil ($/bbl)	**58.37**	47.43	23	**56.02**	43.85	28
Natural gas ($/mcf)	**7.42**	6.99	6	**7.31**	6.83	7
NGL's ($/bbl)	**46.13**	38.22	21	**46.35**	35.26	31
Total commodity revenue before hedging ($/boe)	**50.22**	43.82	15	**48.91**	41.69	17
Other revenue ($/boe)	**0.18**	0.27	(33)	**0.16**	0.17	(6)
Total revenue before hedging ($/boe)	**50.40**	44.09	14	**49.07**	41.86	17

(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 eight per cent to $251.6 million in the second quarter of 2005 compared to $233.3 million in the second quarter of 2004. Significantly higher commodity prices, primarily for oil, contributed to this higher revenue.

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

	Three Months Ended June 30			Six Months Ended June 30		
Revenue ($ thousands) [(1)]	**2005**	2004	% Change	**2005**	2004	% Change
Oil revenue	**117,108**	98,070	19	**223,270**	185,095	21
Natural gas revenue	**116,964**	118,815	(2)	**231,057**	224,352	3
NGL's revenue	**16,631**	15,000	11	**33,694**	27,707	22
Total commodity revenue	**250,703**	231,885	8	**488,021**	437,154	12
Other revenue	**893**	1,422	(37)	**1,629**	1,747	(7)
Total revenue before hedging [(1)]	**251,596**	233,307	8	**489,650**	438,901	12

(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 hedging activities are conducted by an internal Risk Management Committee, based upon guidelines approved by the Board.

In response to the increased volatility characterized by current commodity markets, the Trust continues to execute a hedging strategy focused on price floor (put) structures to manage commodity prices and uses 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 hedges as they meet the objectives of the Trust's risk management mandate.

In order to mitigate credit risk, the Trust executes commodity and foreign currency hedging transactions with financially sound, credit worthy counterparties. All contracts require approval of the Trust's Risk Management Committee prior to execution.

In the second quarter of 2005, the Trust terminated certain 2006 crude oil contracts resulting in a payment of $6.1 million that reduced cash flow from operations in the second quarter. Subsequent to the termination of the contracts, the Trust has upside participation on all 2006 production.

ARC's current portfolio of hedges 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, approximately 80 per cent of the Trust's 2005 oil (and liquids) and 67 per cent of the natural gas production will participate in the market price of the commodity with downside protection on approximately 48 per cent of the Trust's production, well above budgeted levels required to maintain distributions. For 2006, the Trust has 100 per cent upside on both oil and gas production and downside protection on approximately three per cent of production.

The Trust is committed to pay $20.6 million in option premiums on a portion of 2005 and 2006 hedged volumes. The premiums on the put contracts will be recorded as a realized cash hedging loss when payment is made in a future period. These premiums may be partially offset if ARC sells any short term options. The Trust's oil contracts are based on the WTI index and the majority of the Trust's natural gas contracts are based on the AECO monthly index.

The table below illustrates ARC's average hedged price, total corporate price in 2005 and commodity hedge gains and losses as a result of the Trust's 2005 commodity hedging program at various commodity prices. The foreign exchange table illustrates the gains and losses pursuant to the Trust's foreign exchange hedges at various CAD/USD exchange rates.

Impact of 2005 Hedging	**Q3-Q4 2005 Commodity Price and Foreign Exchange Rate Assumptions**			
Oil				
Oil price per barrel (US$/WTI)	$30.00	$40.00	$50.00	$60.00
ARC's average hedged price (US$/barrel) (1)	$37.34	$37.91	$40.28	$46.28
Average price on forecasted volumes (US$/WTI) (1)	$34.69	$39.68	$45.55	$53.18
Oil hedging gains (losses) CDN$ millions (2) (3)	$14.9	$(10.0)	$(29.7)	$(38.9)
Natural Gas				
Gas price per Gigajoule (CDN$/GJ)	$6.00	$7.00	$8.00	$9.00
ARC's average hedged price (CDN$/GJ)	$6.31	$6.59	$7.30	$7.68
Average price on forecasted volumes (CDN$/GJ)	$6.20	$6.80	$7.60	$8.21
Natural gas hedging gains (losses) CDN$ millions (3)	$0.9	$(6.4)	$(7.6)	$(14.3)
Foreign Exchange				
Foreign exchange rate (CAD/USD)	$1.25	$1.22	$1.19	$1.16
Foreign exchange rate (USD/CAD)	$0.80	$0.82	$0.84	$0.86
Foreign exchange hedge gains (losses) CDN$ millions(3)	$(2.8)	$(0.3)	$2.0	$4.3

(1) Incorporates the impact of hedging premiums.
(2) Based on foreign exchange rate assumption of USD/CAD$0.825.
(3) Intrinsic value.

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 $0.9 million in the second quarter of 2005, comprising an unrealized fair value gain of $26.3 million and a realized cash loss of $27.2 million.

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

Commodity and foreign currency contracts ($ thousands)	**Crude Oil & Liquids**	**Natural Gas**	**Foreign Currency**	**Q2 2005 Total**	Q2 2004 Total
Realized cash (loss) on contracts [1]	**(22,380)**	**(3,882)**	**(970)**	**(27,232)**	(17,972)
Non-cash gain on contracts [2]	**-**	**-**	**-**	**-**	1,050
Non-cash amortization of opening deferred hedge (loss) [3]	**-**	**-**	**-**	**-**	(4,328)
Unrealized gain (loss) on contracts, change in fair value [4]	**20,242**	**9,422**	**(3,350)**	**26,314**	(5,698)
Total gain (loss) on commodity and foreign currency contracts	**(2,138)**	**5,540**	**(4,320)**	**(918)**	(26,948)

(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 $70.7 million as at March 31, 2005 and a loss of $44.4 million as at June 30, 2005.

Operating Netbacks

The Trust's operating netback, after realized hedging losses, increased six per cent to $26.49 per boe in the second quarter of 2005 compared to $24.93 per boe in the second quarter of 2004. The increase in netbacks in 2005 is primarily due to higher realized commodity prices.

The netbacks incorporate realized losses on commodity and foreign currency contracts of $5.46 per boe for the second quarter of 2005, compared to losses of $3.20 per boe in the second quarter of 2004. (Unrealized fair value changes on commodity and foreign currency contracts of a gain of $26.3 million and a loss of $5.7 million in the second quarter of 2005 and 2004, respectively, were not recorded as a reduction of the netback.)

The components of operating netbacks are shown below:

	Q2 2005				Q2 2004
Netback	Oil ($/bbl)	Gas ($/mcf)	NGL ($/bbl)	**Total ($/boe)**	Total ($/boe)
Weighted average sales price	58.37	7.42	46.13	**50.22**	43.82
Other revenue	-	-	-	**0.18**	0.27
Total revenue	58.37	7.42	46.13	**50.40**	44.09
Royalties	(11.56)	(1.53)	(11.99)	**(10.34)**	(8.64)
Transportation	(0.17)	(0.22)	-	**(0.76)**	(0.68)
Operating costs [1]	(9.46)	(1.01)	(4.84)	**(7.35)**	(6.64)
Netback prior to hedging	37.18	4.66	29.30	**31.95**	28.13
Realized loss on commodity and foreign currency contracts[2]	(11.64)	(0.25)	-	**(5.46)**	(3.20)
Netback after hedging	25.54	4.41	29.30	**26.49**	24.93

Netback	Oil ($/bbl)	Gas ($/mcf)	NGL ($/bbl)	YTD 2005 Total ($/boe)	YTD 2004 Total ($/boe)
Weighted average sales price	56.02	7.31	46.35	**48.90**	41.69
Other revenue	-	-	-	**0.16**	0.17
Total revenue	56.02	7.31	46.35	**49.06**	41.86
Royalties	(10.59)	(1.44)	(12.28)	**(9.67)**	(8.06)
Transportation	(0.17)	(0.21)	-	**(0.74)**	(0.71)
Operating costs (1)	(8.06)	(0.99)	(5.09)	**(6.73)**	(6.55)
Netback prior to hedging	37.20	4.67	28.98	**31.92**	26.54
Realized (loss) gain on commodity and foreign currency contracts(2)	(9.47)	0.10	-	**(3.46)**	(2.68)
Netback after hedging	27.73	4.77	28.98	**28.46**	23.86

(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 contracts of a gain of $26.3 million and a loss of $5.7 million in the second quarters of 2005 and 2004, respectively.

Royalties increased to $10.34 per boe in the second quarter of 2005 compared to $8.64 per boe in the second quarter of 2004. The increase in royalties per boe is the result of higher commodity prices in the second quarter of 2005 relative to 2004 and also due to changes in the Saskatchewan Resource Surcharge introduced in the March 23, 2005 Saskatchewan Budget that increased royalties by $1.9 million in the second quarter of 2005. The resource surcharge is calculated based on a rate applicable to working interest oil and natural gas revenue earned in Saskatchewan, with a rate of 3.6 per cent from wells drilled prior to October 1, 2002 and a rate of two per cent from wells drilled on or after October 1, 2002. Approximately 25 per cent of the Trust's current operations are in Saskatchewan.

As a result, royalties as a percentage of pre-hedged commodity revenue net of transportation costs increased 0.9 per cent to 20.8 per cent compared to 19.9 per cent in the second quarter of 2004. 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 to $36.7 million in the second quarter of 2005 compared to $35.2 million in the same period of 2004. There has been upward pressure on operating costs during the second quarter in all areas of operations. Scheduled gas plant turnarounds in the second quarter caused gas production reductions during the turnaround period.

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

Transportation costs increased twelve per cent to $0.76 per boe in the second quarter of 2005, compared to $0.68 per boe in the second 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 June 30			Six Months Ended June 30		
	2005	2004	% Change	**2005**	2004	% Change
Cash component:						
G&A prior to whole unit plan	**6,392**	5,406	18	**12,558**	10,285	22
Per boe	**1.28**	1.02	25	**1.26**	0.98	29
Whole unit plan expense	**955**	-	100	**955**	-	100
Cash G&A expense	**7,347**	5,406	36	**13,513**	10,285	31
Per boe	**1.47**	1.02	44	**1.35**	0.98	38
Non cash components:						
Rights plan	**1,807**	565	220	**3,481**	3,410	2
Whole unit plan	**99**	645	(85)	**406**	645	(37)
	9,253	6,616	40	**17,400**	14,340	21
Per boe	**1.85**	1.25	48	**1.74**	1.37	27

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

Under the Trust's Whole Unit Trust Incentive Plan a cash payout of $1.4 million was made to employees in April 2005 (of which $1 million was allocated to G&A with the remainder allocated to operating costs and capital programs), the first anniversary of the plan, which resulted in the reporting of a higher cash portion of G&A compared to the prior quarter.

The Rights Plan, which has been discontinued with the introduction of the Trust's Whole Unit Trust Incentive Plan, has 1.7 million rights outstanding at the end of the quarter. The expenses associated with the Rights Plan were $1.8 million in the quarter compared to $0.6 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 show ARC's total G&A being in the mid-range compared to the Trust's peers in the conventional oil and gas sector.

Interest Expense

Interest expense decreased to $3.3 million in the second quarter of 2005 from $4.8 million in the second quarter of 2004. Refinancing costs caused the higher 2004 interest expenses as in the second quarter of 2004, the Trust issued $125 million of U.S. denominated fixed rate debt. With the issuance of the US$125 million of fixed rate debt, the Trust repaid all Canadian denominated revolving credit facilities that were at a lower variable interest rate. The issuance of the fixed rate debt was undertaken in order to capitalize on low long-term interest rates in the United States.

Debt increased in the second quarter 2005 over the second quarter of 2004 due to several acquisitions funded entirely through debt.

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

Interest Expense	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2005**	2004	% Change	**2005**	2004	% Change
Period end debt balance [1]	**319,628**	254,676	26	**319,628**	254,676	26
Fixed rate debt	**224,285**	254,676	(12)	**224,285**	254,676	(12)
Floating rate debt	**95,343**	-	100	**95,343**	-	100
Interest expense before interest rate swaps [2]	**3,579**	5,246	(32)	**7,048**	7,864	(10)
Gain on interest rate hedge	**(244)**	(473)	(48)	**(574)**	(473)	21
Net interest expense	**3,335**	4,773	(30)	**6,474**	7,391	(12)

(1) Includes both long-term and current portions of debt.
(2) The interest rate swap was designated as an effective hedge for accounting purposes whereby actual realized gains and losses are netted against interest expense.

Foreign Exchange Gains and Losses

The Trust recorded a loss of $3.1 million ($0.62 per boe) on foreign exchange transactions in the second quarter of 2005 compared to a loss of $4.4 million ($0.82 per boe) in the second quarter of 2004. 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 second 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.

The following is a breakdown of the total foreign exchange (loss):

Foreign Exchange (Loss)	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except per boe)	**2005**	2004	% Change	**2005**	2004	% Change
Unrealized (loss) on U.S. denominated debt	**(2,926)**	(806)	263	**(3,999)**	(1,749)	129
Realized (loss) on U.S. denominated transactions	**(156)**	(3,546)	(96)	**(109)**	(3,303)	(97)
Total Foreign exchange (loss)	**(3,082)**	(4,352)	(29)	**(4,108)**	(5,052)	(19)
Total Foreign exchange (loss) per boe	**(0.62)**	(0.82)	(24)	**(0.41)**	(0.48)	(15)

Taxes

In the second quarter of 2005, a future income tax expense of $5.6 million was included in income compared to a $5.5 million recovery in the second 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 $26.3 million in the second quarter of 2005 compared to $10 million in the second 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.

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 by ARC Resources.

Depletion, Depreciation and Accretion of Asset Retirement Obligation

The depletion, depreciation and accretion ("DD&A") rate increased to $12.53 per boe in the second quarter of 2005 from $11.29 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. Future development capital increased from $315.8 million to $374.2 million for proved reserves from January 1, 2004 to January 1, 2005. In addition, total proved reserves decreased by four per cent at January 1, 2005 compared to January 1, 2004 as a result of the non-core property divestment in the second quarter of 2004. 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 June 30			Six Months Ended June 30		
($ thousands except per boe amounts)	**2005**	2004	% Change	**2005**	2004	% Change
Depletion of oil & gas assets [1]	**61,300**	58,552	5	**122,515**	115,998	6
Accretion of asset retirement obligation [2]	**1,266**	1,167	8	**2,512**	2,333	8
Total DD&A	**62,566**	59,719	5	**125,027**	118,331	6
DD&A rate per boe	**12.53**	11.29	11	**12.53**	11.29	11

(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 June 30, 2005.

Capital Expenditures and Net Acquisitions

Total capital expenditures, excluding acquisitions and dispositions, totaled $45.5 million in the second quarter of 2005 compared to $34.1 million in the second 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.

In the second quarter of 2005, in addition to the capital expenditures, the Trust completed net property and corporate acquisitions for $123.7 million (before adjusting for future taxes of $18.5 million) in the following areas: Berrymoor and Buck Creek in Alberta and Weirhill and Steelman in Saskatchewan. The property acquisitions were financed primarily by debt, which resulted in the Trust's long term debt increasing from $220 million at December 31, 2004 to $366 million at June 30, 2005. These acquisitions, in aggregate, are expected to contribute approximately 2,100 boe/d in the third quarter of 2005.

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

	Three Months ended June 30		Six Months Ended June 30	
Capital Expenditures ($ thousands)	**2005**	2004	**2005**	2004
Geological and geophysical	**2,659**	1,373	**3,920**	3,693
Drilling and completions	**33,465**	24,867	**69,514**	62,808
Plant and facilities	**8,703**	7,282	**23,192**	23,238
Other capital	**652**	605	**1,373**	947
Total capital expenditures	**45,479**	34,127	**97,999**	90,686
Producing property acquisitions (1)	**81,526**	830	**85,370**	2,509
Producing property dispositions (1)	**(2,805)**	(54,242)	**(2,981)**	(54,347)
Corporate acquisition (1) (2)	**62,456**	30,560	**62,456**	30,560
Total capital expenditures and net acquisitions	**186,656**	11,275	**242,844**	69,408
Capital expenditures and net acquisitions financed with cash flow	**33,613**	34,127	**86,133**	59,252
Capital expenditures and net acquisitions financed with debt and equity	**153,043**	(22,852)	**156,711**	10,156

(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 June 30, 2005, the Trust has recorded an Asset Retirement Obligation ("ARO") of $81.1 million ($64.2 million at June 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 $1 million for actual abandonment expenditures incurred in the second quarter of 2005. In addition, the Trust increased its asset retirement obligations by $4.6 million to reflect new engineering estimates and $3.1 million for retirement obligations on assets acquired in the quarter. 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 second quarter of 2005 ($1.5 million in the second quarter of 2004) and earned interest of $0.2 million ($0.3 million in 2004) on the fund balance. The fund balance was reduced by $1.3 million for cash-funded abandonment expenditures in the second quarter of 2005 ($1.3 million in the second quarter of 2004). This fund, which aggregated $22.3 million as of June 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)	**June 30, 2005**	March 31, 2005	December 31, 2004
Long-term debt	**311,049**	218,189	211,834
Short-term debt	**8,579**	8,467	8,715
Working capital deficit excluding short-term debt (1)	**46,588**	27,596	44,293
Net debt obligations	**366,216**	254,252	264,842
Units outstanding and issuable for exchangeable shares (thousands)	**191,329**	189,609	188,804
Market price per unit at end of period	**19.94**	18.15	17.90
Market value of trust units and exchangeable shares	**3,815,100**	3,441,403	3,379,592
Total capitalization (2)	**4,181,316**	3,695,655	3,644,434
Net debt as a percentage of total capitalization	**8.8%**	6.9%	7.3%
Cash flow from operations	**263,774**	141,965	448,033
Net debt to annualized cash flow	**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. The Trust recently completed the annual credit review that resulted in the borrowing base and terms of the credit facility remaining unchanged. ARC Resources' and ARC (Sask) Trust's oil and gas properties continue to secure the debt.

As at June 30, 2005 net debt to total capitalization was 8.8 per cent and net debt to annualized second quarter YTD 2005 cash flow was approximately 0.7 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 77 per cent of its second quarter capital development program of $45.5 million with cash flow. The balance was funded by share proceeds on the distribution reinvestment program and the exercise of rights.

Unitholders' Equity

At June 30, 2005, there were 191.3 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 1.7 million rights outstanding as of June 30, 2005 are exercised or cancelled as no additional rights will be issued under the plan due to discontinuation of the plan in the second 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 1.7 million trust units at an average adjusted exercise price of $10.73 were outstanding at June 30, 2005. These rights have an average remaining contractual life of 2.8 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 June 30, 2005 there were 697,932 RTU's and PTU's outstanding under the Whole Unit Plan of which 72,932 RTU's vested on April 15, 2005 and resulted in a cash payment of $1.4 million, including accrued distributions, to the holders of the RTU's. 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 which 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 $35.4 million at June 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 second quarter 2005 and 2004 net income, respectively, of $1.2 million and $0.8 million, represents the net income attributable to the exchangeable shareholders for the second quarters of 2005 and 2004, respectively. As the exchangeable shares are converted to trust units, Unitholders' capital is increased for the book value of the trust units issued.

As at June 30, 2005 there were 1.7 million exchangeable shares of ARL outstanding at an exchange ratio of 1.75594 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 second 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 $84.5 million ($0.45 per unit), representing 69 per cent of second quarter 2005 cash flow compared to cash distributions of $82.1 million ($0.45 per unit), representing 67 per cent of cash flow in the second quarter of 2004. The remaining 31 per cent of second quarter 2005 cash flow of $121.8 million was used to fund 77 per cent of ARC's second quarter 2005 capital expenditures of $45.5 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:

Cash flow and distributions	Three Months Ended June 30 2005	2004	% Change	Three Months Ended June 30 2005	2004	% Change
	($ millions)			($ per unit) [2]		
Cash flow from operations	**121.8**	122.2	-	**0.64**	0.66	(3)
Reclamation fund contributions [1]	**(1.7)**	(1.8)	6	**(0.01)**	(0.01)	-
Capital expenditures funded with cash flow	**(35.6)**	(34.1)	(4)	**(0.19)**	(0.19)	(-)
Discretionary debt repayments	**-**	(4.2)	-	**-**	(0.02)	-
Other [2]	**-**	-	-	**0.01**	0.01	-
Cash distributions	**84.5**	82.1	3	**0.45**	0.45	-

Cash flow and distributions	Six Months Ended June 30 2005	2004	% Change	Six Months Ended June 30 2005	2004	% Change
	($ millions)			($ per unit) [2]		
Cash flow from operations	**263.8**	230.3	15	**1.39**	1.25	11
Reclamation fund contributions [1]	**(3.4)**	(3.5)	3	**(0.02)**	(0.02)	-
Capital expenditures funded with cash flow	**(88.2)**	(59.3)	(49)	**(0.47)**	(0.33)	(42)
Discretionary debt repayments	**(3.9)**	(4.2)	(7)	**(0.02)**	(0.02)	-
Other [2]	**-**	-	-	**0.02**	0.02	-
Cash distributions	**168.3**	163.3	3	**0.90**	0.90	-

(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 third quarter of 2005 have been set at $0.15 for the August 15, 2005 payment and will increase to $0.17 effective with the September 15, 2005 distribution. 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 July 15, 2005:

Calendar Year	Distributions (1)	Taxable Portion	Return of Capital
2005 YTD (2)	1.05 (2)	1.00 (2)	0.05 (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	**$15.14**	**$8.44**	**$6.70**

(1) Based on cash distributions paid in the calendar year.
(2) Based on cash distributions paid in 2005 up to and including July 15, 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	
November 28, 2005	November 30, 2005	December 15, 2005	

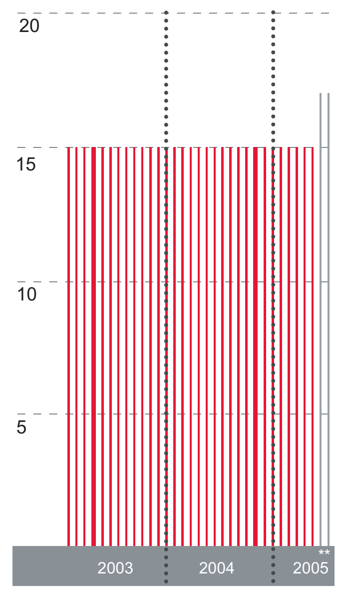
* Estimated

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.

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.

MONTHLY CASH DISTRIBUTIONS
(CAD cents/trust unit)



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

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.

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

($ millions)	2005	2006-2007	2008-2009	Thereafter	Total
Debt repayments (1)	8.6	127.2	36	147.8	319.6
Operating leases	2.4	4.9	4.2	2.1	13.6
Purchase commitments	3.9	3.4	2.7	8.0	18.0
Retention bonuses	1.0	2.0	-	-	3.0
Derivative contract premiums (2)	17.2	3.4	-	-	20.6
Total contractual obligations	33.1	140.9	42.9	157.9	374.8

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

The Trust enters into commitments for capital expenditures in advance of the expenditures being made. At a given point in time, it is estimated that the Trust has committed to 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 June 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 derivative put contracts. Premiums of approximately $20.6 million will be paid in 2005 and 2006 for the put contracts in place at June 30, 2005. As the premiums are part of the underlying derivative contract, they have been recorded at fair market value at June 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 $35.4 million and $36 million, respectively, on the Trust's consolidated balance sheet as at June 30, 2005 and December 31, 2004. Consolidated net income has been reduced for net income attributable to the non-controlling interest of $1.2 million and $0.8 million, respectively, in the second 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 second quarter of 2004 has been reduced by $0.8 million to $50.3 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:

Variable Interest Entities – In June 2003, the CICA issued Accounting Guideline 15 "Consolidation of Variable Interest Entities" which deals with the consolidation of entities that are subject to control on a basis other than ownership of voting interests. This new guideline is effective for fiscal years beginning on or after November 1, 2004. The Trust has assessed that this guideline has no current impact based on the current structure. The Trust will consider the applicability of this guideline in the future and assess the appropriate financial statement implications at that time.

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.

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 half of 2005, the Trust provided unitholders with a return of 16 per cent.

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 budget is subject to Board approval. 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 half of 2005:

	2005 Annual Guidance		2005 Actual
	Original	Revised	Q1 & Q2
Production (boe/d)	54,800	56,000	55,133
Expenses ($/boe):			
Operating costs	7.00	7.00	6.73
Transportation	0.70	0.70	0.74
G&A expenses – cash	1.25	1.25	1.26
G&A expenses – stock compensation plans	0.30	0.60	0.48
Interest	0.75	0.75	0.65
Cash taxes	0.15	0.15	0.10
Capital expenditures ($ millions)	240	270	98
Weighted average trust units and units issuable (millions)	191.0	191.3	189.7

The Trust expects to complete the year 2005 in accordance with revised Guidance targets released in August 2005. To the end of the second quarter of 2005 there were some variances between annual guidance and actuals to the end of the first quarter, 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. As workover and maintenance activities are undertaken in the second and third 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 in the first two quarters, 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 the first half of 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 $0.10 for the first half of 2005 were below the guidance level of $0.15 as an overpayment of capital taxes in 2004 was given back to the Trust on assessment. In addition, the overall capital tax rate has commenced phase-out based on new federal legislation which eliminates the federal capital tax by 2006.

In the first half of 2005, the Trust incurred $98 million of capital expenditures pursuant to the original $240 million 2005 capital development program. 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.

2005 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]	$ 50.00	$ 1.00	$ 0.05	1.7%
Natural gas price (CDN$AECO/mcf) [1]	$ 7.00	$ 0.10	$ 0.03	1.0%
USD/CAD exchange rate	$ 0.82	$ 0.01	$ 0.05	1.8%
Interest rate on debt	5.1%	1.0%	$ 0.01	0.5%
Operational				
Liquids production volume (bbls/d)	26,500	1.0%	$ 0.02	0.6%
Gas production volumes (Mmcf/d)	170.0	1.0%	$ 0.02	0.6%
Operating expenses per boe	$ 7.00	1.0%	$ 0.01	0.3%
Cash G&A expenses per boe	$ 1.25	10.0%	$ 0.02	0.6%

(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.

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	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Revenue before royalties	**251,596**	238,054	232,112	230,769	233,307	205,594	182,558	184,166
Per unit (1)	**1.32**	1.26	1.23	1.23	1.26	1.12	1.04	1.11
Cash flow	**121,808**	141,965	106,935	110,835	122,249	108,014	89,617	87,511
Per unit (1)	**0.64**	0.75	0.57	0.59	0.66	0.59	0.51	0.53
Net income (5)	**73,215**	38,646	112,995	38,897	50,338	39,460	53,492	40,785
Per unit – basic (5) (6)	**0.39**	0.21	0.61	0.21	0.28	0.22	0.31	0.25
Per unit – diluted	**0.38**	0.20	0.60	0.21	0.27	0.22	0.31	0.25
Cash distributions	**84,468**	83,867	83,531	83,178	82,053	81,215	78,603	73,890
Per unit (2)	**0.45**	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Total assets (8)	**2,427,463**	2,303,948	2,304,998	2,316,297	2,309,599	2,278,608	2,281,775	2,251,273
Total liabilities (8)	**895,179**	785,776	755,650	804,603	768,073	752,166	730,039	886,887
Net debt outstanding (4)	**366,216**	254,252	264,842	220,500	220,074	284,001	262,071	412,686
Weighted average units (thousands) (3)	**187,388**	186,224	185,539	184,675	181,949	180,283	171,993	163,334
Units outstanding and issuable at period end (thousands)	**191,329**	189,609	188,804	188,185	187,296	183,980	182,777	167,531
CAPITAL EXPENDITURES ($ thousands)								
Geological and geophysical	**2,659**	1,262	867	828	1,373	2,320	2,846	1,171
Drilling and completions	**33,465**	36,042	39,125	42,553	24,867	37,942	37,738	31,661
Plant and facilities	**8,703**	14,495	6,183	11,668	7,282	15,956	15,512	11,917
Other capital	**652**	721	1,480	394	605	341	1,418	391
Total capital expenditures	**45,479**	52,520	47,655	55,443	34,127	56,559	57,515	45,140
Property acquisitions (dispositions), net	**78,721**	3,668	(1,036)	(5,345)	(53,412)	1,574	(3,693)	(81,166)
Corporate acquisitions (7)	**62,456**	-	41,449	-	30,560	-	-	258
Total capital expenditures and net acquisitions	**186,656**	56,188	88,068	50,098	11,275	58,133	53,822	(35,768)
OPERATING								
Production								
Crude oil (bbl/d)	**22,046**	21,993	22,969	22,496	22,720	23,663	22,851	23,522
Natural gas (Mmcf/d)	**173,116**	176,073	174.7	177.4	186.7	174.5	180.8	182.0
Natural gas liquids (bbl/d)	**3,962**	4,072	4,097	4,034	4,313	4,323	4,140	4,105
Total (boe/d 6:1)	**54,860**	55,410	56,179	56,096	58,147	57,075	57,120	57,968
Average prices								
Crude oil ($/bbl)	**58.37**	53.63	49.48	51.00	47.43	40.41	35.21	35.33
Natural gas ($/mcf)	**7.42**	7.20	6.82	6.65	6.99	6.64	5.85	5.64
Natural gas liquids ($/bbl)	**46.13**	46.57	43.72	42.30	38.22	32.30	30.14	30.92
Oil equivalent ($/boe) (9)	**50.40**	47.74	44.91	44.72	44.09	39.58	34.78	34.53
TRUST UNIT TRADING (based on intra-day trading)								
Unit prices								
High	**20.30**	20.40	17.98	17.38	15.74	15.74	14.87	13.88
Low	**16.88**	16.55	14.80	15.02	14.28	13.50	13.31	12.51
Close	**19.94**	18.15	17.90	16.85	15.35	15.64	14.74	13.55
Average daily volume (thousands)	**605**	895	456	384	337	502	395	551

(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 June 30 and December 31 (unaudited)

($CDN thousands)	2005	2004
ASSETS		
Current assets		
Cash and cash equivalents	**$ -**	$ 4,413
Accounts receivable	**88,310**	72,881
Prepaid expenses	**13,779**	9,878
Commodity and foreign currency contracts (Note 6)	**1,303**	22,294
	103,392	109,466
Reclamation fund	**22,280**	21,294
Property, plant and equipment	**2,144,199**	2,016,646
Goodwill	**157,592**	157,592
Total assets	**$ 2,427,463**	$ 2,304,998
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**$ 120,391**	$ 103,572
Cash distributions payable	**28,286**	27,893
Current portion of long-term debt (Note 4)	**8,579**	8,715
Commodity and foreign currency contracts (Note 6)	**45,718**	26,336
	202,974	166,516
Long-term debt (Note 4)	**311,049**	211,834
Other long-term liabilities (Note 5)	**5,085**	3,893
Asset retirement obligations (Note 7)	**81,093**	73,001
Future income taxes (Note 8)	**294,978**	300,406
Total liabilities	**895,179**	755,650
NON-CONTROLLING INTEREST		
Exchangeable shares (Note 9)	**35,381**	35,967
UNITHOLDERS' EQUITY		
Unitholders' capital (Note 10)	**1,968,232**	1,926,351
Contributed surplus (Note 11)	**4,591**	6,475
Accumulated earnings	**990,668**	878,807
Accumulated cash distributions (Note 13)	**(1,466,588)**	(1,298,252)
Total unitholders' equity	**1,496,903**	1,513,381
Total liabilities and unitholders' equity	**$ 2,427,463**	$ 2,304,998

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENT OF INCOME AND ACCUMULATED EARNINGS

For the three and six months ended June 30 (unaudited)

($CDN thousands, except per unit amounts)	Three Months Ended June 30 2005	Three Months Ended June 30 2004	Six Months Ended June 30 2005	Six Months Ended June 30 2004
		Restated (Note 2)		Restated (Note 2)
Revenue				
Oil, natural gas, natural gas liquids and sulphur sales	**251,596**	233,307	**489,650**	438,901
Royalties	**(51,643)**	(45,713)	**(96,482)**	(84,470)
	199,953	187,594	**393,168**	354,431
Realized (loss) on commodity and foreign currency contracts (Note 6)	**(27,232)**	(17,973)	**(34,546)**	(31,528)
Unrealized gain (loss) on commodity and foreign currency contracts (Note 6)	**26,314**	(8,975)	**(40,373)**	(30,167)
	199,035	160,646	**318,249**	292,736
Expenses				
Transportation	**3,781**	3,610	**7,367**	7,439
Operating	**36,672**	35,158	**67,113**	68,680
General and administrative - cash	**7,347**	5,406	**13,513**	10,285
General and administrative - non-cash (Notes 11 and 12)	**1,906**	1,210	**3,888**	4,055
Interest on long-term debt	**3,335**	4,773	**6,474**	7,391
Depletion, depreciation and accretion	**62,566**	59,719	**125,027**	118,331
Loss on foreign exchange	**3,082**	4,352	**4,108**	5,052
	118,689	114,228	**227,490**	221,233
Income before taxes	**80,346**	46,418	**90,759**	71,503
Capital taxes	**(337)**	(737)	**(987)**	(1,400)
Future income tax (expense) recovery (Note 8)	**(5,600)**	5,500	**23,900**	21,200
Net income before non-controlling interest	**74,409**	51,181	**113,672**	91,303
Non-controlling interest (Note 9)	**(1,194)**	(843)	**(1,811)**	(1,505)
Net income	**73,215**	50,338	**111,861**	89,798
Accumulated earnings, beginning of period	**917,453**	687,764	**878,807**	648,304
Accumulated earnings, end of period	**990,668**	738,102	**990,668**	738,102
Net income per unit (Note 14)				
Basic	**0.39**	0.28	**0.60**	0.50
Diluted	**0.38**	0.27	**0.58**	0.48

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

For the three and six months ended June 30 (unaudited)

($CDN thousands)	Three Months Ended June 30		Six Months Ended June 30	
	2005	2004	**2005**	2004
		Restated (Note 2)		Restated (Note 2)
CASH FLOW FROM OPERATING ACTIVITIES				
Net income	**73,215**	50,338	**111,861**	89,798
Add items not involving cash:				
Non-controlling interest	**1,194**	843	**1,811**	1,505
Future income tax expense (recovery)	**5,600**	(5,500)	**(23,900)**	(21,200)
Depletion, depreciation and accretion	**62,566**	59,719	**125,027**	118,331
Non-cash (gain) loss on commodity and foreign currency contracts (Note 6)	**(26,314)**	5,697	**40,373**	22,172
Unrealized loss on foreign exchange	**2,926**	6,664	**3,999**	7,607
Amortization of commodity and foreign currency contracts	**-**	3,278	**-**	7,995
Non-cash trust unit incentive compensation (Note 11 and 12)	**2,621**	1,210	**4,603**	4,055
Funds from operations	**121,808**	122,249	**263,774**	230,263
Expenditures on site restoration and reclamation	**(1,041)**	(407)	**(2,088)**	(1,337)
Change in non-cash working capital	**7,150**	73,884	**(5,033)**	78,756
	127,917	195,726	**256,653**	307,682
CASH FLOW FROM FINANCING ACTIVITIES				
Issuance of long-term debt, net	**90,129**	2,217	**95,163**	14,668
Issue of trust units	**11,842**	8,195	**14,901**	13,639
Trust unit issue costs	**(11)**	(16)	**(13)**	(16)
Cash distributions paid	**(73,667)**	(74,841)	**(148,712)**	(148,363)
Change in non-cash working capital	**(1,811)**	(67,687)	**36**	(67,928)
	26,482	(132,132)	**(38,625)**	(188,000)
CASH FLOW FROM INVESTING ACTIVITIES				
Corporate acquisition, net of cash received (Note 3)	**(42,182)**	(60)	**(42,182)**	(60)
Acquisition of petroleum and natural gas properties	**(81,525)**	(830)	**(85,369)**	(2,509)
Proceeds on disposition of petroleum and natural gas properties	**2,804**	54,242	**2,980**	54,347
Capital expenditures	**(49,737)**	(40,791)	**(97,591)**	(100,651)
Net reclamation fund contributions	**(412)**	(517)	**(986)**	(2,193)
Changes in non-cash working capital	**16,653**	(4,968)	**707**	(5,850)
	(154,399)	7,076	**(222,441)**	(56,916)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**-**	70,670	**(4,413)**	62,766
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	**-**	4,391	**4,413**	12,295
CASH AND CASH EQUIVALENTS, END OF PERIOD	**-**	75,061	**-**	75,061

See accompanying notes to consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

June 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 second 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 $35.4 million and $36 million, respectively, in the Trust’s consolidated balance sheet as at June 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 $1.5 million, respectively, for the first six 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

		June 30, 2005		December 31, 2004
Revolving credit facilities				
Working capital facility	**$**	**95,343**	$	290
Senior secured notes				
8.05% USD Note		**34,317**		33,701
4.94% USD Note		**36,768**		36,108
Long-term notes				
4.62% USD Note		**76,600**		75,225
5.10% USD Note		**76,600**		75,225
Total debt outstanding	**$**	**319,628**	$	220,549
Current portion of debt		**8,579**		8,715
Long-term debt	**$**	**311,049**	$	211,834

5. OTHER LONG-TERM LIABILITIES

		June 30, 2005	December 31, 2004
Retention bonuses	$	2,000	$ 2,000
Accrued long-term incentive compensation		3,085	1,893
Total other long-term liabilities	**$**	**5,085**	$ 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 2006 and August 2007.

The accrued long-term incentive compensation represents the long-term portion of the Trust's estimated liability for the Whole Unit Plan as at June 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 June 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						
Jul 05 – Jul 05	3 Way[(1)]	1,000	-	47.32	44.00	63.00
Jul 05 – Jul 05	3 Way[(1)]	1,000	-	47.32	44.00	60.00
Jul 05 – Dec 05	3 Way	500	-	34.00	30.00	41.75
Jul 05 – Dec 05	Swap	4,000	28.95	-	-	-
Jul 05 – Dec 05	Put Spread	2,000	-	47.05	29.00	-
Jul 05 – Dec 05	Put Spread	1,000	-	46.65	33.00	-
Jul 05 – Dec 05	Put Spread	3,500	-	46.36	30.00	-
Sep 05 – Sep 05	Put Spread	1,000	-	47.32	29.00	-
Aug 05 – Aug 05	3 Way	1,000	-	47.32	29.00	60.00
Aug 05 – Aug 05	3 Way	1,000	-	47.32	29.00	62.00
Sep 05 – Sep 05	3 Way	1,000	-	47.32	29.00	65.00
Oct 05 – Dec 05	Put Spread	2,000	-	47.32	29.00	-
2005 Weighted Average		**13,000**	**28.95**	**46.07**	**30.45**	**54.41**
2006						
Jan 06 – Mar 06	Bought Put	2,000	-	50.00	-	-
Jan 06 – Jun 06	Put Spread	2,000	-	50.00	40.00	-
2006 Weighted Average		**1,485**	**-**	**50.00**	**40.00**	**-**

(1) Includes additional embedded sold put at US$29 (CDN $35.54).

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						
Jul 05 – Oct 05	3 Way	10,000	-	6.00	5.00	8.00
Jul 05 – Oct 05	3 Way	5,000		6.50	5.50	7.55
Jul 05 – Oct 05	3 Way	5,000	-	6.50	5.50	8.00
Jul 05 – Oct 05	Collar	10,000	-	6.42	-	8.00
Jul 05 – Oct 05	Bought Put	5,000	-	6.75	-	-
Jul 05 – Oct 05	Bought Put	10,000	-	6.85	-	-
Jul 05 – Oct 05	Bought Put	10,000	-	6.99	-	-
Jul 05 – Oct 05	Bought Put	10,000	-	7.42	-	-
Jul 05 – Oct 05	Collar	10.000	-	6.65	-	8.00
Jul 05 – Jul 05	Collar	10,000	-	6.65	-	8.00
Jul 05 – Jul 05	Collar	10,000	-	6.63	-	8.25
Aug 05 – Aug 05	Collar	10,000	-	6.65	-	8.00
Aug 05 – Aug 05	Collar	10,000	-	6.63	-	8.75
Sep 05 – Sep 05	Collar	10,000	-	6.65	-	8.25
Sep 05 – Sep 05	Collar	10,000	-	6.63	-	8.25
Oct 05 – Oct 05	Collar	10,000	-	6.65	-	10.00
Oct 05 – Oct 05	Bought Put	10,000	-	6.63	-	-
Nov 05 – Dec 05	Bought Put	10,000	-	8.00	-	-
2005 Weighted Average		**66,821**		**6.75**	**5.25**	**8.11**
2006						
Jan 06 – Mar 06	Bought Put	10,000	-	8.00	-	-
2006 Weighted Average		**2,466**		**8.00**	**-**	**-**

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						
Jul 05 – Oct 05	Collar	10,000	-	6.50	-	8.00
Jul 05 – Oct 05	Collar	10,000	-	6.50	-	8.00
2005 Weighted Average		**13,370**	**-**	**6.50**	**-**	**8.00**

Financial Natural Gas AECO Basis Contracts

Term	Contract	Volume mmbtu/d	Swap US$/mmbtu
2005			
Jul 05 – Oct 05	Swap	10,000	(0.865)
Jul 05 – Oct 05	Swap	10,000	(0.840)
2005 Weighted Average		**13,370**	**(0.853)**

Financial Foreign Exchange Contracts

Term	Contract	Volume MM US$	Swap CDN$/US$	Swap US$/CDN$
USD Sales Contracts				
2005				
Jul 05 – Oct 05	Swap	15.9	1.2384	0.8075
Jul 05 – Dec 05	Swap	17.9	1.2153	0.8228
Jul 05 – Dec 05	Swap	27.1	1.2115	0.8254
Jul 05 – Dec 05	Swap	14.3	1.2169	0.8218
Jul 05 – Dec 05	Swap	21.4	1.2000	0.8333
Total and 2005 Weighted Average		**96.6**	**1.2149**	**0.8231**
2006				
Jan 06 – Jun 06	Swap	6.5	1.2115	0.8254
Jan 06 – Jun 06	Swap	6.5	1.2000	0.8333
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				
Jul 05 – Dec 05	Swap	8.1	1.1966	0.8357

Financial Electricity Contracts[1]

Term	Contract	Volume MWh	Swap CDN$/MWh
Jul 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
Jul 05 – Apr 14	Swap	30.5	4.62	38.5 bps
Jul 05 – Apr 14	Swap	32.0	4.62	38 bps
Total and Annual Weighted Average		**62.5**	**4.62**	**38.2 bps**

(1) Interest rate swap contracts have 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 six months of 2005 on the electricity contract has been included in operating costs. The fair value unrealized gain on the electricity contract of $2.4 million has not been recorded on the consolidated balance sheet at June 30, 2005.

The Trust has entered into interest rate swap contracts to manage the Company's interest rate exposure on debt instruments. These contracts have been designated as effective accounting hedges on the contract date. A realized gain of $0.6 million for the first six months of 2005 on the interest rate swap contracts has been included in interest expense. The fair value unrealized gain on the interest rate swap contracts of $0.2 million has not been recorded on the consolidated balance sheet at June 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:

	June 30, 2005	June 30, 2004
Fair value, beginning of period [1]	$ (4,042)	$ (14,575)
Fair value, end of period [1]	(44,415)	(36,747)
Change in fair value of contracts in the period	(40,373)	(22,172)
Realized losses in the period	(34,546)	(31,528)
Amortization of crystallized hedging gains	-	3,464
Amortization of opening mark to market loss	-	(11,459)
Loss on commodity and foreign currency contracts [1]	$ (74,919)	$ (61,695)

	June 30, 2005	December 31, 2004
Commodity and foreign currency contracts liability	$ (45,718)	$ (26,336)
Commodity and foreign currency contracts asset	$ 1,303	$ 22,294

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

At June 30, 2005, the fair value of the contracts that were not designated as accounting hedges was a loss of $44.4 million. The Trust recorded a loss on commodity and foreign currency contracts of $74.9 million and $61.7 million in the statement of income for the first six 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:

	June 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	(2,088)	(3,232)
Accretion expense	2,512	4,580
Balance, end of period	$ 81,093	$ 73,001

8. INCOME TAXES

The future income tax expense of $5.6 million in the second quarter of 2005 included an expense of $9 million due to the unrealized gain of $26.3 million on commodity and foreign currency contracts. In the second quarter of 2004, the future income tax recovery of $5.5 million included a recovery of $3.5 million for the $10 million unrealized loss on commodity and foreign currency contracts. For the first six months of 2005, the Trust recorded a future income tax recovery of $23.9 million which included a recovery of $13.8 million due to the unrealized loss of $40.4 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	June 30, 2005	June 30, 2004
Balance at beginning of period	1,784	2,011
Exchanged for trust units [1]	(117)	(84)
Balance, end of period	1,667	1,927
Exchange ratio, end of period	1.75594	1.58199
Trust units issuable upon conversion, end of period	2,927	3,049

(1) During the first six months of 2005, 116,669 ARL exchangeable shares were converted to trust units at an average exchange ratio of 1.72901.

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

	June 30, 2005	December 31, 2004
Non-controlling interest, beginning of period	**$ 35,967**	$ 36,311
Reduction of book value for conversion to trust units	**(2,397)**	(4,295)
Current period net income attributable to non-controlling interest	**1,811**	3,951
Non-controlling interest, end of period	**$ 35,381**	$ 35,967
Accumulated earnings attributable to non-controlling interest	**$ 16,950**	$ 15,139

10. UNITHOLDERS' CAPITAL

	June 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)	**202**	**2,397**	363	4,295
Issued on exercise of employee rights (Note 11)	**1,239**	**19,573**	1,751	20,672
Distribution reinvestment program	**1,139**	**19,924**	1,896	27,924
Trust unit issue costs	-	**(13)**	-	(152)
Balance, end of period	**188,402**	**1,968,232**	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:

	Weighted Number of Rights	Average Exercise Price ($)
Balance, beginning of period	**3,009**	**10.92**
Exercised	**(1,239)**	**11.46**
Cancelled	**(74)**	**11.20**
Balance before reduction of exercise price	**1,696**	**11.09** [(1)]
Reduction of exercise price	**-**	**(0.36)**
Balance, end of period	**1,696**	**10.73** [(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 $3.5 million for the first six months of 2005 and 2004 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, 270,332 rights have been cancelled and 1,290,641 rights have been exercised to June 30, 2005.

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

CONTRIBUTED SURPLUS	June 30, 2005	December 31, 2004
Balance, beginning of period	**$ 6,475**	$ 3,471
Compensation expense	**3,481**	5,171
Net benefit on rights exercised [(1)]	**(5,365)**	(2,167)
Balance, end of period	**$ 4,591**	$ 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 six months ended June 30, 2005, the Trust recorded a change in compensation liability relating to the Whole Trust Unit Incentive Plan of $1.5 million. The compensation liability was based on the June 30, 2005 trust unit closing price of $19.94, distributions of $0.15 per unit per month during the quarter, 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 six months ended June 30, 2005.

	Number of RTU's	Number of PTU's
Balance, beginning of period	224	128
Granted	226	211
Exercised	(78)	-
Forfeited	(8)	(6)
Balance, end of period	364	333

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 June 30		Six Months Ended June 30	
	2005	2004	**2005**	2004
Funds from operations before changes in non-cash working capital	**121,808**	122,249	**263,774**	230,263
Add (deduct):				
Cash withheld to fund capital expenditures	**(35,663)**	(34,128)	**(88,183)**	(59,251)
Reclamation fund contributions and interest earned on fund	**(1,677)**	(1,842)	**(3,395)**	(3,518)
Discretionary debt repayments	**-**	(4,225)	**(3,860)**	(4,225)
Cash distributions [2]	**84,468**	82,054	**168,336**	163,269
Accumulated cash distributions, beginning of period	**1,382,120**	1,049,490	**1,298,252**	968,275
Accumulated cash distributions, end of period	**1,466,588**	1,131,544	**1,466,588**	1,131,544
Cash distributions per unit [1]	**0.45**	0.45	**0.90**	0.90
Accumulated cash distributions per unit, beginning of period	**14.69**	12.89	**14.24**	12.44
Accumulated cash distributions per unit, end of period	**15.14**	13.34	**15.14**	13.34

(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 of $10 million ($7 million – 2004) and $19 million ($15 million – 2004) for the three and six months ended June 30, 2005, respectively. These non-cash amounts relate 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 June 30		Six Months Ended June 30	
	2005	2004[4]	**2005**	2004[4]
Weighted average units[1]	**187,388**	181,949	**186,810**	181,118
Trust units issuable on conversion of exchangeable shares[2]	**2,927**	3,049	**2,927**	3,049
Dilutive impact of rights[3]	**1,671**	1,604	**1,917**	1,840
Diluted trust units	**191,986**	186,602	**191,654**	186,007

(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 June 30, 2005:

($ millions)	2005	2006-2007	2008-2009	Thereafter	Total
Debt repayments [1]	8.6	127.2	36	147.8	319.6
Operating leases	2.4	4.9	4.2	2.1	13.6
Purchase commitments	3.9	3.4	2.7	8.0	18.0
Retention bonuses	1.0	2.0	-	-	3.0
Derivative contract premiums [2]	17.2	3.4	-	-	20.6
Total contractual obligations	33.1	140.9	42.9	157.9	374.8

(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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AUDITORS

Deloitte & Touche LLP
Calgary, Alberta

ENGINEERING CONSULTANTS

Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta

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

2005

October 17	Announcement of Q4 Distribution Monthly Amounts
November 3	2005 Q3 Results

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

Susan D. Healy
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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

NOTES

ARC ENERGY TRUST