NEWS RELEASE
May 7, 2009

ARC ENERGY TRUST ANNOUNCES FIRST QUARTER 2009 RESULTS

Calgary, May 7, 2009 (AET.UN and ARX – TSX) ARC Energy Trust ("ARC" or "the Trust") announces the results for the first quarter ended March 31, 2009.

	Three Months Ended March 31	
	2009	2008
FINANCIAL		
(Cdn$ millions, except per unit and per boe amounts)		
Revenue before royalties	**225.2**	407.9
Per unit (1)	**0.98**	1.91
Per boe	**38.57**	66.94
Cash flow from operating activities (2)	**124.3**	209.9
Per unit (1)	**0.54**	0.98
Per boe	**21.29**	34.44
Net income	**22.3**	81.3
Per unit (3)	**0.10**	0.39
Distributions	**82.0**	126.8
Per unit (1)	**0.36**	0.60
Per cent of cash flow from operating activities (2)	**66**	60
Net debt outstanding (4)	**781.5**	770.1
OPERATING		
Production		
Crude oil (bbl/d)	**28,806**	29,064
Natural gas (mmcf/d)	**193.8**	204.3
Natural gas liquids (bbl/d)	**3,764**	3,856
Total (boe/d)	**64,872**	66,976
Average prices		
Crude oil ($/bbl)	**46.44**	89.72
Natural gas ($/mcf)	**5.20**	7.80
Natural gas liquids ($/bbl)	**38.86**	68.54
Oil equivalent ($/boe)	**38.40**	66.67
Operating netback ($/boe)		
Commodity and other revenue (before hedging) (5)	**38.57**	66.94
Transportation costs	**(0.95)**	(0.73)
Royalties	**(6.34)**	(11.85)
Operating costs	**(10.12)**	(9.55)
Netback (before hedging)	**21.16**	44.81
TRUST UNITS		
(millions)		
Units outstanding, end of period (6)	**236.0**	214.7
Weighted average trust units (7)	**228.9**	213.8
TRUST UNIT TRADING STATISTICS		
(Cdn$, except volumes) based on intra-day trading		
High	**20.90**	27.06
Low	**11.73**	20.00
Close	**14.15**	26.38
Average daily volume (thousands)	**1,240**	863

(1) Per unit amounts (with the exception of per unit distributions) are based on weighted average trust units outstanding plus trust units issuable for exchangeable shares. Per unit distributions are based on the number of trust units outstanding at each distribution record date.
(2) Cash flow from operating activities is a GAAP measure. Historically, management has disclosed Cash Flow as a non-GAAP measure calculated using cash flow from operating activities less the change in non-cash working capital and the expenditures on site restoration and reclamation as they appear on the Consolidated Statements of Cash Flows. Cash Flow for the first quarter of 2009 would be $116.6 million ($0.51 per unit). Distributions as a percentage of Cash Flow would be 70 per cent for the first quarter of 2009. Please refer to the non-GAAP measures section in the MD&A for further details.
(3) Net income per unit is based on net income after non-controlling interest divided by weighted average trust units outstanding (excluding trust units issuable for exchangeable shares).
(4) Net debt excludes current unrealized amounts pertaining to risk management contracts and the current portion of future income taxes.
(5) Includes other revenue.
(6) For the first quarter of 2009, includes 0.9 million (1.2 million in 2008) exchangeable shares exchangeable into 2.577 trust units (2.314 in 2008) each for an aggregate 2.4 million (2.7 million in 2008) trust units.
(7) Includes trust units issuable for outstanding exchangeable shares at period end.

ACCOMPLISHMENTS / FINANCIAL UPDATE

- The Trust completed an equity offering of 15.5 million trust units at $16.35 per unit for net proceeds of $240 million during the quarter. Proceeds of the offering were applied against the Trust's debt resulting in a net debt balance of $781.5 million at March 31, 2009, a reduction of $180.4 million from year end.

- On April 14, 2009, the Trust announced the closing of a private placement of long-term debt in the form of senior secured notes totaling US$125 million at a blended average interest rate of 7.47 per cent. The notes were offered in three tranches with repayment dates between 2012 and 2021 allowing the Trust to convert a portion of its credit facility debt to long term notes that mature over a number of years as opposed to being re-financed all in one year. Proceeds from the notes were used to reduce the debt outstanding on the Trust's $800 million credit facility to $356 million, providing the Trust with $444 million of undrawn debt capacity on the bank line. The Trust also has $167 million available to it through the undrawn portion of a shelf facility with a large insurance company.

- The Trust executed a $97.2 million capital expenditure program in the first quarter of 2009 that included drilling 81 gross wells on operated properties, resulting in 14 oil wells, 66 natural gas wells and a 99 per cent success rate. Of the 81 wells drilled in the first quarter, the Trust currently has 33 wells waiting on tie-in, of which 24 wells are awaiting completion. The capital expenditures were 64 per cent funded by cash flow from operating activities and proceeds from the DRIP program and the remaining portion was funded through debt.

- Production for the quarter was on budget at 64,872 boe per day with record production at Dawson and Ante Creek. With the reduction in the 2009 capital budget, the Trust now expects full year production to average between 62,000 and 64,000 boe per day at an operating cost of approximately $10.70 per boe.

- In light of the weak commodity price environment, particularly for natural gas, the monthly distribution has been decreased to $0.10 per unit effective with the May distribution payable on June 15, 2009. The Board has also approved a reduced capital expenditure budget for the Trust of $350 million while affirming its commitment to the construction of a 60 mmcf per day gas plant to be completed late in the first quarter of 2010 for the Dawson field contingent on the timely receipt of regulatory approvals.

- The Trust's current plans are to convert to a dividend paying Corporation effective December 31, 2010. At this time, management believes that this will be most logical and tax efficient alternative for ARC unitholders. The potential conversion will be subject to regulatory and unitholder approval.

- **Montney Resource Play Development**
  During the first quarter of 2009, the Trust spent $36.3 million on development activities in the Dawson area including the drilling of five horizontal wells, two of which were completed and tested during the quarter. Vertical wells were also drilled at Sundown and Pouce Coupe.

  With the completion of a third party compressor in the middle of February, total production from the Dawson area grew to an average of 51.2 mmcf per day in the first quarter of 2009 and exited the quarter at approximately 56 mmcf per day.

  The Trust continues to work towards a late first quarter 2010 completion date for a new 60 mmcf per day gas plant for Dawson. Design work is complete, long-lead time items have been ordered and the public notification has been completed. Applications have been submitted to the appropriate regulatory agencies and are currently under review.

- **Enhanced Oil Recovery Initiatives**
  During the first quarter, the Trust spent $7 million on enhanced oil recovery ("EOR") initiatives. The Redwater CO_2 pilot project is well underway and on schedule with the highlight of the quarter being the start-up of the associated production facility. The Trust expects that it will take at least until 2010 before it will know to what extent the pilot has been successful in increasing oil production. While the pilot project may indicate enhanced recovery, the current outlook for crude oil prices and the cost and availability of CO_2 may hinder the Trust's ability to achieve commercial viability for a full scale EOR scheme.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This management's discussion and analysis ("MD&A") is the Trust management's analysis of its financial performance and significant trends or external factors that may affect future performance. It is dated May 5, 2009 and should be read in conjunction with the unaudited Consolidated Financial Statements for the period ended March 31, 2009 and the audited Consolidated Financial Statements and MD&A as at and for the year ended December 31, 2008 as well as the Trust's Annual Information Form that is filed on SEDAR at www.sedar.com.

The MD&A contains Non-GAAP measures and forward-looking statements and readers are cautioned that the MD&A should be read in conjunction with the Trust's disclosure under "Non-GAAP Measures" and "Forward-Looking Statements" included at the end of this MD&A.

Executive Overview

ARC Energy Trust ("ARC") is one of the top 20 producers of conventional oil and gas in western Canada. As at March 31, 2009, ARC held interests in excess of 18,600 wells with approximately 5,600 wells operated by ARC and the remainder operated primarily by other major oil and gas companies. ARC's production has averaged between 61,000 and 67,000 boe per day in each quarter for the last three years. The total capitalization of ARC, which trades on the Toronto Stock Exchange, as at March 31, 2009 was $4.1 billion as shown on Table 22.

ARC's objective as an energy company is to provide superior and sustainable long-term returns to unitholders. Key attributes of the business plan include:

- Concentrated activities in three major business areas: conventional oil and natural gas assets, resource plays and enhanced oil recovery initiatives. In addition to these major initiatives, ARC continually reviews acquisition and disposition opportunities to high-grade its asset base and provide future growth opportunities.

- Pay a portion of cash flow to unitholders. Currently the Trust distributes $0.12 per unit per month but due to current oil and natural gas prices the distribution amount has been decreased to $0.10 per unit per month starting with the May distribution to be paid on June 15, 2009. The remainder of the cash flow is used to fund reclamation costs, and a portion of capital expenditures and land acquisitions. Since the Trust's inception in July 1996 to March 31, 2009, the Trust has distributed $3.3 billion or $24.06 per unit.

- Declining commodity prices have caused management to defer some 2009 capital projects to future periods resulting in a reduced capital budget of $350 million for 2009. A key focus is to construct a gas plant at Dawson and expand production from the Montney. Approximately half of ARC's $350 million capital program will support this key initiative. The remaining capital is targeted at key assets across western Canada. Calculated on a boe basis, normalized production per thousand units has decreased slightly from 0.30 to 0.27 while the Trust has made distributions of $5.43 per unit or $1.15 billion from January 1, 2007 through to March 31, 2009. Details of the calculations for normalized production and reserves per unit are provided in Table 1.

- The periodic acquisition of strategic producing and undeveloped properties to enhance current production or provide the potential for future drilling locations and if successful, additional production and reserves.

- Use prudent production practices to maximize the recovery of oil and natural gas from the reservoirs.

- Operational excellence for both routine operating expenditures and costs incurred for capital projects. In the current environment ARC is aggressively pursuing cost reductions throughout the business. ARC expects that the aggregate amount of operating costs will increase over time as ARC adds approximately 300 wells per year to its operating base to replace the natural decline on existing producing wells.

ARC's business plan and operating practices also include the following strategies and action plans that are being undertaken to increase ARC's competitiveness and future profitability:

- Continual development of staff expertise and the hiring and retention of some of the industry's best and most qualified personnel.

- Building relationships with suppliers, joint venture partners, government and other stakeholders and conducting business in a fair and equitable manner.

- Reviewing the corporate structure in order to optimize returns to investors with the commencement of the trust taxation on January 1, 2011. ARC's most likely course of action will be to convert to a corporation, subject to unitholder approval.

- Promoting the use of proven and effective technologies to enhance the recoverable resources in place and reduce costs.

- Being an industry leader in health, safety and environmental performance.

- Actively supporting local initiatives and charities in the communities in which the Trust's employees live and work.

Table 1

Per Trust Unit	**First quarter 2009**	Full year 2008	Full year 2007
Normalized production per unit (1) (2)	**0.27**	0.29	0.30
Normalized reserves per unit (1) (3)	**n/a**	1.42	1.35
Distributions per unit	**$0.36**	$2.67	$2.40

(1) Normalized indicates that all years as presented have been adjusted to reflect a net debt to capitalization of 15 per cent. It is assumed that additional trust units were issued (or repurchased) at a period end price for the reserves per unit calculation and at an annual average price for the production per unit calculation in order to achieve a net debt balance of 15 per cent of total capitalization each year. The normalized amounts are presented to enable comparability of annual per unit values.
(2) Production per unit represents daily average production (boe) per thousand trust units. Calculated based on daily average production divided by the normalized weighted average trust units outstanding including trust units issuable for exchangeable shares.
(3) Reserves per unit are calculated based on proved plus probable reserves (boe) divided by period end trust units outstanding including trust units issuable for exchangeable shares.

ARC's business plan has achieved significant operational success. However, commodity prices and the current economic crisis are significant factors determining profitability of ARC and capital appreciation of our trust units in the market place. The negative impact of external factors has led to a negative return for the trailing one and three years despite the successful execution of ARC's business plan and operational successes.

Table 2

Total Returns (1) ($ per unit except for per cent)		**Trailing One Year**		Trailing Three Year		Trailing Five Year
Distributions per unit	**$**	**2.63**	$	7.23	$	11.17
Capital appreciation per unit	**$**	**(12.23)**	$	(13.21)	$	(1.49)
Total return per unit	**$**	**(9.60)**	$	(5.98)	$	9.68
Annualized total return per unit		**(40.2)%**		(10.9)%		8.6%
S&P/TSX Capped Energy Trust Index		**(40.8)%**		(15.0)%		5.2%

(1) Calculated as at March 31, 2009.

2009 Guidance

Table 3 is a summary of the Trust's 2009 Revised Guidance and a review of 2009 actual results compared to guidance:

Table 3

	2009 Guidance	2009 Actual YTD	% Change	**2009 Revised Guidance**
Production (boe/d)	64,000-65,000	64,872	-	**62,000 – 64,000**
Expenses ($/boe):				
Operating costs	10.70	10.12	(5)	**10.70**
Transportation	1.15	0.95	(17)	**1.00**
G&A expenses (cash & non-cash)	2.80	0.88	(69)	**2.10**
Interest	1.85	0.99	(46)	**1.30**
Capital expenditures ($ millions)	450	97.2	-	**350**
Annual weighted average trust units and trust units issuable (millions)	235	229	(3)	**238**

The 2009 Guidance provides unitholders with information on management's expectations for results of operations for 2009. Readers are cautioned that the 2009 Guidance may not be appropriate for other purposes.

The following revisions have been made to the Trust's 2009 guidance.

- Production levels have been revised as a result of the Trust's reduction in capital expenditures discussed below. The Trust now expects that 2009 full year production will be in the range of 62,000 to 64,000 boe per day. Production guidance numbers for 2010 are under review and will change due to the impact of decreased capital expenditures in 2009 and the current uncertainty with regards to capital plans for 2010.

- Transportation expenses have been revised downward to $1.00 per boe. Initial guidance was based on expectations of increased oil transportation charges resulting from apportionment on the main Enbridge pipeline as well as reduced capacity on the Saskatchewan Enbridge pipeline. These restrictions have not materialized year-to-date and therefore the Trust has re-forecast full year transportation expense to be approximately $1.00 per boe.

- G&A expenses are expected to decrease to $2.10 per boe most significantly as a result of a decrease in the costs for the Trust's Whole Unit Plan. The cash whole unit plan expense is expected to decrease from $0.85 per boe to $0.55 per boe based on the reduction of the trust unit price and distributions in 2009. The non-cash whole unit plan expense is expected to decrease from an expense of $0.15 per boe to a recovery of $0.20 per boe as the cash payout in March 2009 was based on an actual price of $12.18 per unit as compared to the $20.10 that was accrued for this payment at year-end 2008. Cash G&A costs, excluding the whole unit plan expense for the full year 2009 are expected to decrease to $1.75 from $1.80 as a result of a reduction in variable compensation costs.

- Interest expense has been revised downward to reflect the lower interest rates on the Trust's floating rate debt as well as the Trust's lower debt balance subsequent to the equity offering completed in February 2009. These amounts will be partially offset by higher interest rates on the Trust's new senior secured long-term notes issued in April 2009 that have a blended average interest rate of 7.47 per cent. See, Capitalization, Financial Resources and Liquidity section of this MD&A for details.

- Capital Expenditures have been revised downward to $350 million from the previous guidance of $450 million. The Trust has re-evaluated all capital projects in light of the ongoing challenges with low commodity prices. The key focus for the 2009 capital program remains in the Montney area. For the full year 2009, the Trust plans to drill 122 gross wells on operated properties as compared to 191 gross wells that were planned under the $450 million capital expenditure guidance. Items that have been deferred until 2010 include a 75 well shallow gas drilling program in the Brooks area, three horizontal wells in the Redwater area and four horizontal wells and two vertical wells in the Dawson area. The Trust is anticipating potential cost savings on the planned capital expenditures for the remainder of 2009 which, if realized, may create an opportunity to fund additional strategic projects. In addition, the Trust is currently evaluating the Alberta government's corporate royalty drilling credit program that was announced on March 3, 2009 in order to assess the viability of additional capital programs using the revised royalty rates.

2009 First Quarter Financial and Operational Results

Following is a discussion of ARC's 2009 first quarter financial and operating results.

Financial Highlights

Table 4

	Three Months Ended March 31		
(Cdn $ millions, except per unit and volume data)	**2009**	2008	% Change
Cash flow from operating activities	**124.3**	209.9	(41)
Cash flow from operating activities per unit (1)	**0.54**	0.98	(45)
Net income	**22.3**	81.3	(73)
Net income per unit (2)	**0.10**	0.39	(74)
Distributions per unit (3)	**0.36**	0.60	(40)
Distributions as a per cent of cash flow from operating activities	**66**	60	10
Average daily production (boe/d) (4)	**64,872**	66,976	(3)

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

Net Income

As a result of decreased commodity prices, the Trust's net income and cash flows were negatively impacted during the first quarter. Net income in the first quarter of 2009 was $22.3 million ($0.10 per unit), a decrease of $59 million from $81.3 million ($0.39 per unit) in the first quarter of 2008. The decrease in net income is largely attributed to the $85.6 million decrease in cash flow from operating activities from the first quarter of 2008 (see Table 6 for details), along with the following non-cash items:

- The Trust recorded a $12.1 million non-cash recovery for its long-term incentive whole unit plan that increased net income in the first quarter of 2009 compared to an expense of $13.8 million for the same period of 2008. (See - General and Administrative Expenses and Trust Unit Incentive Compensation for details)

- The Trust recorded a future income tax recovery of $12.2 million that increased net income in the first quarter of 2009 compared to a future tax expense of $0.5 million for the first quarter of 2008.

- The Trust recorded a $6.6 million non-cash loss on risk management contracts in the first quarter of 2009 compared to a loss of $18.7 million recorded in the same period of 2008. (See - Risk Management and Hedging Activities for details).

A measure of sustainability is the comparison of net income to distributions. Net income incorporates all costs including depletion expense and other non-cash expenses whereas cash flow from operating activities measures the cash generated in a given period before the cost of acquiring or replacing the associated reserves produced. Therefore, net income may be more representative of the profitability of the entity and thus a relevant measure against which to measure distributions to illustrate sustainability. As net income is sensitive to fluctuations in commodity prices and the impact of risk management contracts, currency fluctuations and other non-cash items, it is expected that there will be deviations between annual net income and distributions. Table 5 illustrates the annual shortfall of distributions to net income as a measure of long-term sustainability.

Table 5

Net income and Distributions ($ millions except per cent)	First quarter 2009	Full year 2008	Full year 2007
Net income	22.3	533.0	495.3
Distributions	82.0	570.0	498.0
Excess (Shortfall)	(59.7)	(37.0)	(2.7)
Excess (Shortfall) as per cent of net income	(268%)	(7%)	(1%)
Cash flow from operating activities	124.3	944.4	704.9
Distributions as a per cent of cash flow from operating activities	66%	60%	71%

Cash Flow from Operating Activities
Cash flow from operating activities decreased by 41 per cent in the first quarter of 2009 to $124.3 million from $209.9 million in the first quarter of 2008. The decrease in 2009 cash flow from operating activities is detailed in Table 6.

Table 6

	($ millions)	($ per trust unit)	(% variance)
Q1 2008 Cash flow from Operating Activities	**209.9**	**0.98**	**-**
Volume variance	(17.2)	(0.08)	(8)
Price variance	(165.3)	(0.76)	(79)
Cash (losses) and gains on risk management contracts	45.8	0.21	22
Royalties	35.2	0.16	17
Expenses:			
Transportation	(1.2)	(0.01)	(1)
Operating [(1)]	(4.1)	(0.02)	(2)
Cash G&A	(6.7)	(0.03)	(3)
Interest	3.0	0.01	1
Realized foreign exchange loss	(0.2)	-	-
Weighted average trust units	-	(0.04)	-
Non-cash and other items [(2)]	25.1	0.12	12
Q1 2009 Cash flow from Operating Activities	**124.3**	**0.54**	**(41)**

(1) Excludes non-cash portion of Whole Unit Plan expense recorded in operating costs.
(2) Includes the changes in non-cash working capital and expenditures on site restoration and reclamation.

2009 Cash Flow from Operating Activities Sensitivity
Table 7 illustrates sensitivities to pre-hedged operating income items with operational changes and changes to the business environment:

Table 7

			Impact on Annual Cash flow from operating activities [(2)]			
Business Environment		Assumption		Change		$/Unit
Oil price (US$WTI/bbl) [(1)]	$	50.00	$	1.00	$	0.04
Natural gas price (Cdn $AECO/mcf) [(1)]	$	4.80	$	0.10	$	0.02
Cdn$/US$ exchange rate		1.20	$	0.01	$	0.02
Interest rate on debt	%	3.95	%	1.0	$	0.02
Operational						
Liquids production volume (bbl/d)		31,500	%	1.0	$	0.02
Gas production volumes (mmcf/d)		189.0	%	1.0	$	0.01
Operating expenses per boe	$	10.70	%	1.0	$	0.01
Cash G&A and LTIP expenses per boe	$	2.30	%	10.0	$	0.02

(1) Analysis does not include the effect of hedging contracts.
(2) Assumes constant working capital.

Production
Production volumes averaged 64,872 boe per day in the first quarter of 2009 compared to 66,976 boe per day in the same period of 2008 as detailed in Table 8. In the first quarter of 2008, the Trust recorded a 1,000 boe per day natural gas volume adjustment due to prior period measurement errors at the Ante Creek property made by the facility operator. In the first quarter of 2009, the Trust has posted record production in the Ante Creek and Dawson areas helping to offset declines in shallow gas production in southeast Alberta and southwest Saskatchewan. New production in the Delburne area from the Trust's natural gas from coal drilling program was also realized in the first

quarter of 2009.

Table 8

	Three Months Ended March 31		
Production	**2009**	2008	% Change
Light & medium crude oil (bbl/d)	**27,720**	27,718	-
Heavy oil (bbl/d)	**1,086**	1,346	(19)
Natural gas (mmcf/d)	**193.8**	204.3	(5)
NGL (bbl/d)	**3,764**	3,856	(2)
Total production (boe/d) (1)	**64,872**	66,976	(3)
% Natural gas production	**50**	51	(2)
% Crude oil and liquids production	**50**	49	2

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

Light and medium crude oil production remained constant at 27,720 boe per day compared to 27,718 boe per day in 2008, while heavy oil production declined by 19 per cent. Natural gas production was 193.8 mmcf per day in the first quarter of 2009, a decrease of five per cent from the 204.3 mmcf per day produced in the first quarter of 2008.

The Trust's objective is to maintain annual production through the drilling of wells and other development activities. In fulfilling this objective, there may be fluctuations in production depending on the timing of new wells coming on-stream. During the first quarter of 2009, the Trust drilled 81 gross wells (57 net wells) on operated properties; 14 gross oil wells, and 66 gross natural gas wells with a 99 per cent success rate.

The Trust expects that 2009 full year production will be approximately 62,000 to 64,000 boe per day and that 122 gross wells (101 net wells) will be drilled by ARC on operated properties with participation in an additional 54 gross wells to be drilled on the Trust's non-operated properties. The Trust estimates that the revised 2009 drilling program will add sufficient production from new wells to offset the majority of production declines on existing properties, however, overall production is expected to decrease by 2,000 to 3,000 boe per day. The planned capital expenditures are being continuously monitored in the context of the current economic environment and will be revised as required.

Table 9 summarizes the Trust's production by core area:

Table 9

	Three Months Ended March 31, 2009				Three Months Ended March 31, 2008			
Production Core Area (1)	**Total (boe/d)**	**Oil (bbl/d)**	**Gas (mmcf/d)**	**NGL (bbl/d)**	Total (boe/d)	Oil (bbl/d)	Gas (mmcf/d)	NGL (bbl/d)
Central AB	**7,127**	**1,390**	**27.7**	**1,116**	7,770	1,460	30.3	1,263
N.E. BC & N.W. AB	**13,619**	**754**	**73.4**	**629**	12,842	852	68.2	626
Northern AB	**9,493**	**4,353**	**25.4**	**907**	10,632	5,054	28.2	874
Pembina & Redwater	**13,798**	**9,648**	**19.1**	**972**	13,998	9,460	21.6	938
S.E. AB & S.W. Sask.	**8,789**	**994**	**46.7**	**15**	10,041	985	54.2	16
S.E. Sask. & MB	**12,046**	**11,667**	**1.5**	**125**	11,693	11,253	1.8	139
Total	**64,872**	**28,806**	**193.8**	**3,764**	66,976	29,064	204.3	3,856

(1) Provincial references: AB is Alberta, BC is British Columbia, Sask. is Saskatchewan, MB is Manitoba, N.E. is northeast, N.W. is northwest, S.E. is southeast and S.W. is southwest.

Revenue

Revenue decreased to $225.2 million in the first quarter of 2009, $182.7 million lower than 2008 revenues of $407.9 million. While oil volumes were relatively unchanged year over year, the decrease in realized oil prices accounted for a $116.9 million decrease in revenues. Natural gas revenue decreased by $54.4 million, comprising a $48.4 million decrease due to lower prices realized in 2009 and a $6 million decrease due to lower volumes produced in 2009.

A breakdown of revenue is outlined in Table 10:

Table 10

Revenue	Three Months Ended March 31		
($ millions)	**2009**	2008	% Change
Oil revenue	**120.4**	237.3	(49)
Natural gas revenue	**90.6**	145.0	(38)
NGL revenue	**13.2**	24.1	(45)
Total commodity revenue	**224.2**	406.4	(45)
Other revenue	**1.0**	1.5	(33)
Total revenue	**225.2**	407.9	(45)

Commodity Prices Prior to Hedging

Table 11

	Three Months Ended March 31		
	2009	2008	% Change
Average Benchmark Prices			
AECO gas ($/mcf) (1)	**5.64**	7.13	(21)
WTI oil (US$/bbl) (2)	**43.21**	97.96	(56)
Cdn$ / US$ foreign exchange rate	**1.25**	1.01	24
WTI oil (Cdn$/bbl)	**53.85**	97.34	(45)
ARC Realized Prices Prior to Hedging			
Oil ($/bbl)	**46.44**	89.72	(48)
Natural gas ($/mcf)	**5.20**	7.80	(33)
NGL ($/bbl)	**38.86**	68.54	(43)
Total commodity revenue before hedging ($/boe)	**38.40**	66.67	(42)
Other revenue ($/boe)	**0.17**	0.27	(37)
Total revenue before hedging ($/boe)	**38.57**	66.94	(42)

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

The sharp decline in oil prices during the fourth quarter of 2008 continued into the first quarter of 2009. US$WTI prices averaged $43.21 throughout the first quarter of 2009, a 56 per cent decrease from the comparable period in 2008. This dramatic decrease was partially offset by the weakening of the Canadian dollar compared to the U.S. dollar, however, widening of the price differentials for the first part of the quarter further eroded the Trust's realized oil price. The Trust's oil production consists predominantly of light and medium crude oil while heavy oil accounts for less than five per cent of the Trust's crude oil production. The realized price for the Trust's oil, before hedging, was $46.44 per boe, a 48 per cent reduction over the first quarter 2008 realized price of $89.72 per boe.

Alberta AECO Hub natural gas prices, which are commonly used as an industry reference, averaged $5.64 per mcf in the first quarter of 2009 compared to $7.13 per mcf in the same period of 2008. ARC's realized gas price, before hedging, decreased by 33 per cent to $5.20 per mcf compared to $7.80 per mcf in the first quarter of 2008. ARC's realized gas price is based on prices received at the various markets in which the Trust sells its natural gas. ARC's natural gas sales portfolio consists of gas sales priced at the AECO monthly index, the AECO daily spot market, eastern and mid-west United States markets and a portion to aggregators. While natural gas prices softened in the first quarter of 2009 compared to the fourth quarter of 2008, prices have continued to decline in the second quarter with posted prices at approximately $3.30 per mcf for the month of April with no improvement expected in the near term as a result of record storage volumes and concern over the state of the North American economy. Unitholders should expect further deterioration in natural gas revenue in the second quarter and likely into the third quarter.

Prior to hedging activities, ARC's total realized commodity price was $38.40 per boe in the first quarter of 2009, a 42 per cent decrease from the $66.67 per boe received prior to hedging in the first quarter of 2008.

Risk Management and Hedging Activities
ARC maintains an ongoing risk management program to reduce the volatility of revenues in order to increase the certainty of distributions, protect acquisition economics, and fund capital expenditures.

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

Lower natural gas prices in the first quarter of 2009 resulted in realized cash gains of $13.5 million on natural gas risk management contracts. Realized cash losses of $1.9 million were recorded on the Trust's crude oil risk management contracts as a result of premiums paid in the first quarter of 2009.

During the first quarter of 2009 the Trust realized a cash gain of $4.5 million due to the unwinding of an interest rate swap risk management contract that converted a portion of the Trust's fixed rate debt to floating rate debt.

ARC's first quarter 2009 results include an unrealized total mark-to-market loss of $6.6 million with a net unrealized mark-to-market loss position of $3.1 million as at March 31, 2009. The net loss position is mostly attributed to losses on the Trust's power and interest contracts. The mark-to-market values represent the market price to buy-out the Trust's contracts as of March 31, 2009 and may differ from what will eventually be realized.

Table 12 summarizes the total gain (loss) on risk management contracts for the year-over-year change as of the first quarter of 2009:

Table 12

Risk Management Contracts ($ millions)	Crude Oil & Liquids	Natural Gas	Foreign Currency	Power[(3)]	Interest	**Q1 2009 Total**	Q1 2008 Total
Realized cash (loss) gain on contracts [(1)]	(1.9)	13.5	-	(0.1)	4.8	**16.3**	(29.5)
Unrealized (loss) gain on contracts [(2)]	(0.4)	3.5	-	(4.2)	(5.5)	**(6.6)**	(18.7)
Total (loss) gain on risk management contracts	**(2.3)**	**17.0**	**-**	**(4.3)**	**(0.7)**	**9.7**	(48.2)

(1) Realized cash gains and losses represent actual cash settlements or receipts under the respective contracts.
(2) The unrealized (loss) gain on contracts represents the change in fair value of the contracts during the period.
(3) Amounts presented in Table 12 exclude a $0.1 million realized gain and an unrealized loss of $3 million for the Trust's power contracts that have been designated as effective hedges for accounting purposes. Realized gains and losses on these contracts are recorded in operating costs and unrealized gains and losses are recorded in the Consolidated Statement of Comprehensive Income and Accumulated Other Comprehensive Income.

The Trust currently limits the amount of forecast production that can be hedged to a maximum 50 per cent with the remaining 50 per cent of production being sold at market prices. The following table is an indicative summary of the Trust's positions for crude oil and natural gas as at March 31, 2009.

Table 13

Hedge Positions As at March 31, 2009 [(1)(2)]	**Q2 2009**		**Q3 2009**		**Q4 2009**		**2010**	
Crude Oil	US$/bbl	bbl/day	US$/bbl	bbl/day	US$/bbl	bbl/day	US$/bbl	bbl/day
Sold Call	-	-	-	-	-	-		
Bought Put	***55.00***	***2,500***	***55.00***	***2,500***	***55.00***	***2,500***	***No hedges in place***	
Sold Put	40.00	2,500	40.00	2,500	40.00	2,500		
Natural Gas	Cdn$/GJ	GJ/day	Cdn$/GJ	GJ/day	Cdn$/GJ	GJ/day	Cdn$/GJ	GJ/day
Sold Call	6.50	40,000	6.50	40,000	7.24	26,739		
Bought Put	***5.38***	***40,000***	***5.38***	***40,000***	***5.93***	***26,739***	***No hedges in place***	
Sold Put	4.50	20,000	4.50	20,000	4.50	20,000		

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

(2) In addition to positions shown here, ARC has entered into additional basis positions until October 2012, an energy equivalent swap until December 31, 2009, as well as a fixed price swap for crude oil for the month of April 2009. Please refer to note 9 in the Notes to the Consolidated Financial Statements for full details of the Trust's risk management positions as of March 31, 2009.

Table 13 should be interpreted as follows using the second quarter 2009 natural gas hedges as an example. To accurately analyze the Trust's hedge position, contracts need to be modeled separately as using average prices and volumes may be misleading.

- If the market price is below $4.50, ARC will receive $5.38 less the difference between $4.50 and the market price on 20,000 GJ per day. For example if the market price is $4.45, the Trust will receive $5.33 on 20,000 GJ per day.
- If the market price is between $4.50 and $5.38, ARC will receive $5.38 on 40,000 GJ per day.
- If the market price is between $5.38 and $6.50, ARC will receive the market price on 40,000 GJ per day.
- If the market price exceeds $6.50, ARC will receive $6.50 on 40,000 GJ per day.

Operating Netbacks

The Trust's operating netback, before realized hedging gains and losses, decreased 53 per cent to $21.16 per boe in the first quarter of 2009 compared to $44.81 per boe in same period of 2008. The decrease in netbacks is due most significantly to the reduced commodity prices in the period as well as higher operating costs and transportation costs and was partially offset by lower royalties corresponding to the lower commodity prices.

The Trust's first quarter 2009 netback, after realized hedging gains and losses, was $23.13 per boe, a 45 per cent decrease from the same period in 2008. The 2009 netback includes net gains recorded on the Trust's crude oil and natural gas contracts during the quarter of $1.79 per boe compared to a net loss of $2.63 per boe recorded for the same period in 2008.

The components of operating netbacks are summarized in Table 14:

Table 14

Netbacks ($ per boe)	Crude Oil ($/bbl)	Heavy Oil ($/bbl)	Gas ($/mcf)	NGL ($/bbl)	**Q1 2009 Total ($/boe)**	Q1 2008 Total ($/boe)
Weighted average sales price	46.76	38.11	5.20	38.86	**38.40**	66.67
Other revenue	-	-	-	-	**0.17**	0.27
Total revenue	46.76	38.11	5.20	38.86	**38.57**	66.94
Royalties	(6.95)	(2.73)	(0.85)	(13.47)	**(6.34)**	(11.85)
Transportation	(0.18)	(1.50)	(0.28)	-	**(0.95)**	(0.73)
Operating costs (1)	(12.74)	(16.03)	(1.30)	(8.01)	**(10.12)**	(9.55)
Netback prior to hedging	26.89	17.85	2.77	17.38	**21.16**	44.81
Realized gain (loss) on risk management contracts	(0.76)	-	0.77	-	**1.97**	(2.63)
Netback after hedging	26.13	17.85	3.54	17.38	**23.13**	42.18

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

Royalties as a percentage of pre-hedged commodity revenue net of transportation decreased to 17 per cent ($6.34 per boe) in the first quarter of 2009 compared to 18 per cent ($11.85 per boe) in 2008. The Alberta Government's New Royalty Framework ("Framework" or "NRF") was effective January 1, 2009 which resulted in an overall decrease in the Trust's royalties that was in line with management's expectations due to the low commodity price environment. The Trust continues to evaluate the amendments to the new royalty framework in order to determine the optimal elections that should be made by the Trust. See Alberta Government New Royalty Framework.

Operating costs increased to $10.12 per boe compared to $9.55 per boe in the first quarter of 2008. Total operating costs increased $0.9 million, or two per cent in the first quarter of 2009. There is a high fixed operating cost component for the Trust's properties resulting in a trend of increased operating costs on a per boe basis as production declines over time. The Trust estimates that full year 2009 operating costs will be approximately $245 million or approximately $10.70 per boe based on annual production of approximately 62,000 to 64,000 boe per day. This includes a six per cent increase for costs associated with the increase in total operated wells in 2009 as compared to 2008.

Alberta Government New Royalty Framework

On April 10, 2008, the Alberta Government announced revisions to the Framework that was legislated in November 2008 and took effect on January 1, 2009.

The revisions to the Framework include the following:

- Increased royalty rates on conventional and non-conventional oil and natural gas production in Alberta whereby royalty rates may increase to a maximum rate of 50 per cent;

- Sliding scale royalty calculations based on a broader range of commodity prices whereby conventional oil and natural gas royalty rates may increase up to maximum prices of approximately Cdn$120 per barrel and Cdn$16 per GJ, respectively;

- The elimination of royalty incentive and royalty holiday programs with the exception of specific programs relating to deep oil and natural gas drilling programs, innovative technology and enhanced recovery programs;

Subsequent to legislation of the NRF, the Alberta Government introduced the Transitional Royalty Plan ("TRP") in response to the anticipated decrease in Alberta development activity resulting from the economic downturn and declining commodity prices. The TRP offers reduced royalty rates for new wells drilled on or after November 19, 2008 through December 31, 2013 that meet certain depth criteria. The TRP is in place for a maximum period of five years to December 31, 2013; all wells will convert to the NRF on January 1, 2014. The TRP is an "elective plan" whereby an election must be filed on an individual well basis to qualify for the TRP. The Trust does not anticipate a significant benefit from the TRP in 2009 as the majority of the Trust's wells converted to the NRF on January 1, 2009.

On March 3, 2009, the Alberta Government announced the Energy Incentive Program ("EIP") in response to the decrease in energy related development activity in the province. The incentive program will work in tandem with the NRF and the TRP and includes the following key elements:

- *Drilling Royalty Credit* – producers will receive a drilling credit for new wells drilled between April 1, 2009 and March 31, 2010. The drilling credit is based on a $200 per meter credit on total meters drilled, however the maximum drilling credit is limited to 10 per cent of 2008 Alberta Crown Royalties paid for companies producing greater than 25,000 boe per day in Alberta. ARC's estimated maximum total drilling credit would be approximately $15 million. The drilling credit will be applied to reduce Alberta Crown Royalties payable in 2009 and 2010.

- *New Well Incentive Program* – new production brought on-stream between April 1, 2009 and March 31, 2010 will qualify for a five per cent Alberta Crown Royalty rate for a period of 12 months subject to volume caps of 50,000 barrels of crown oil production and 150 Mmcf of crown natural gas production.

Approximately 65 per cent of the Trust's production is in Alberta; consequently, the Framework including the TRP and EIP will have a significant impact on the Trust's Alberta and corporate royalty rates. The Trust has completed an assessment of the Framework and has estimated that the Trust's average corporate royalty rate will change from approximately 18 per cent of revenue in 2008 to between 14 and 25 per cent of revenue in 2009 depending upon commodity prices as illustrated in Table 15 and the value of incentives realized in 2009.

Table 15

Royalty Rates – New Royalty Framework				
Edmonton posted oil (Cdn$/bbl) (1)	**$40**	**$60**	**$80**	**$100**
AECO natural gas (Cdn$/GJ) (1)	**$4**	**$6**	**$8**	**$10**
Alberta royalty rate prior to NRF(2)	17.5%	17.5%	17.5%	17.5%
NRF Alberta royalty rate before incentives (3)	12.0%	18.0%	24.0%	29.0%
NRF Alberta royalty after incentives (3) (4)	10.0%	16.5%	22.5%	28.0%
Per cent increase (decrease) - Alberta royalty rate	**(43)%**	**(6)%**	**29%**	**60%**
Corporate royalty rate prior to NRF (2)	18.0%	18.0%	18.0%	18.0%
NRF corporate royalty rate before incentives (3)	15.0%	19.0%	23.0%	26.0%
NRF corporate royalty rate after incentives(3) (4)	14.0%	18.0%	22.0%	25.0%
Per cent increase (decrease) - Corporate royalty rate	**(22)%**	**0%**	**22%**	**39%**
Increase (decrease) in annual Corporate royalties ($Millions)	**$(30.0)**	**$0.0**	**$55.0**	**$130.0**
Increase (decrease) annual cash flow per unit	**$0.13**	**$0.00**	**$(0.23)**	**$(0.55)**

(1) Canadian dollar denominated prices before quality differentials.
(2) Under the previous Alberta Crown Royalty regime, Alberta and Corporate royalty rates were consistent across all price scenarios as price ceilings were exceeded whereby royalty rates changed only marginally across the price scenarios presented.

(3) Estimated royalty rates based on guidelines that are subject to interpretation. Royalty rate includes Crown, Freehold and Gross Overriding royalties for all jurisdictions in which the Trust operates.
(4) Based on estimated incentives of $8 million in 2009 under the drilling credit program and assuming all wells drilled on Crown lands on or after April 1, 2009 will qualify for the five per cent new well incentive rate.

General and Administrative Expenses and Trust Unit Incentive Compensation
G&A net of overhead recoveries on operated properties increased 11 per cent to $10.3 million in the first quarter of 2009 from $9.3 million in 2008. Increases in G&A expenses for 2009 were a result of increased staff costs based on a ten per cent increase in the G&A staff levels on average in the first quarter of 2009 when compared to the same period in 2008.

The Trust paid out $7.6 million under the Whole Trust Unit Incentive Plan ("Whole Unit Plan") in the first quarter of 2009 of which $5.6 million was allocated to G&A with the remainder to operating costs and property, plant and equipment. There were no cash payments made under the Whole Unit Plan in the first quarter of 2008, the vesting date occurred in April and as such a $14.5 million cash expense was recorded in the second quarter financial results in 2008. The next cash payment under the Whole Unit Plan is scheduled to occur in September 2009.

Table 16 is a breakdown of G&A and trust unit incentive compensation expense under the Whole Unit Plan:

Table 16

	Three Months Ended March 31		
G&A and Trust Unit Incentive Compensation Expense			
($ millions except per boe)	**2009**	2008	% Change
G&A expenses	**14.7**	13.2	11
Operating recoveries	**(4.4)**	(3.9)	13
Cash G&A expenses before Whole Unit Plan	**10.3**	9.3	11
Cash Expense – Whole Unit Plan	**5.6**	-	100
Cash G&A expenses including Whole Unit Plan	**15.9**	9.3	71
Accrued compensation - Whole Unit Plan	**(10.8)**	11.9	(191)
Total G&A and trust unit incentive compensation expense	**5.1**	21.2	(76)
Total G&A and trust unit incentive compensation expense per boe	**0.87**	3.47	(75)

A non-cash trust unit incentive compensation recovery ("non-cash compensation recovery") of $10.8 million ($1.85 per boe) was recorded in the first quarter of 2009 compared to an expense of $11.9 million ($1.95 per boe) in 2008. The recovery in 2009 relates in part to a reversal of the accrual for the cash payment made in the quarter as well as a reduction in the liability for the units outstanding at March 31, 2009 due to the reduction in the trust unit price relative to the closing price of the trust units at December 31, 2008. The 2008 non-cash amount relates to estimated costs of the Whole Unit Plan to March 31, 2008 as there were no cash payments during the first quarter of 2008 and therefore no reversals were recorded in the period.

Whole Unit Plan
The Whole Unit Plan results in each employee, officer and director (the "plan participants") receiving cash compensation in relation to the value of a specified number of underlying trust units. The Whole Unit Plan consists of Restricted Trust Units ("RTUs") for which the number of units is fixed and will vest over a period of three years and Performance Trust Units ("PTUs") for which the number of units is variable and will vest at the end of three years.

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

Table 17 shows the changes to the Whole Unit Plan during the first three months of 2009 along with the estimated value of the plan at March 31, 2009:

Table 17

Whole Unit Plan (units in thousands and $ millions except per unit)	Number of RTUs	Number of PTUs	Total RTUs and PTUs
Balance, beginning of period	756	959	1,715
Granted in the period	377	244	621
Vested in the period	(180)	(154)	(334)
Forfeited in the period	(15)	(10)	(25)
Balance, end of period (1)	938	1,039	1,977
Estimated distributions to vesting date (2)	250	377	627
Estimated units upon vesting after distributions	1,188	1,416	2,604
Performance multiplier (3)	-	1.4	-
Estimated total units upon vesting	1,188	2,031	3,219
Trust unit price at March 31, 2009	$14.15	$14.15	$14.15
Estimated total value upon vesting ($ millions)	16.8	28.7	45.5

(1) Based on underlying units before performance multiplier and accrued distributions.
(2) Represents estimated additional units to be issued equivalent to estimated distributions accruing to vesting date.
(3) The performance multiplier only applies to PTUs and was estimated to be 1.4 at March 31, 2009 based on an average calculation of all outstanding grants. The performance multiplier is assessed each period end based on actual results of the Trust relative to its peers except during the first year of each grant where a performance multiplier of 1.0 is used.

The value associated with the RTUs and PTUs is expensed in the statement of income over the vesting period with the expense amount being determined by the trust unit price, the number of PTUs to be issued on vesting, and distributions. In periods where substantial trust unit price fluctuation occurs, the Trust's G&A expense is subject to significant volatility.

Table 18 is a summary of the range of future expected payments under the Whole Unit Plan based on variability of the performance multiplier and units outstanding as at March 31, 2009:

Table 18

Value of Whole Unit Plan as at March 31, 2009	Performance multiplier		
(units thousands and $ millions except per unit)	**-**	**1.0**	**2.0**
Estimated trust units to vest			
RTUs	1,188	1,188	1,188
PTUs	-	1,416	2,832
Total units (1)	**1,188**	**2,604**	**4,020**
Trust unit price (2)	$14.15	$14.15	$14.15
Trust unit distributions per month (2)	$0.12	$0.12	$0.12
Value of Whole Unit Plan upon vesting (3)	**$16.8**	**$36.8**	**$56.9**
2009	3.1	5.2	7.3
2010	6.6	13.2	19.9
2011	4.7	11.3	18.0
2012	2.4	7.1	11.7

(1) Includes additional estimated units to be issued for accrued distributions to vesting date.
(2) Values will fluctuate over the vesting period based on the volatility of the underlying trust unit price and distribution levels. Assumes a future trust unit price of $14.15 and $0.12 per trust unit distributions based on the unit price and distribution levels in place at March 31, 2009. As a result of the current commodity price environment, the monthly distribution has decreased from $0.12 per unit to $0.10 per unit starting with the distribution declared for the month of May and payable on June 15, 2009.
(3) Upon vesting, a cash payment is made equivalent to the value of the underlying trust units. The payment is made on vesting dates in March and September of each year and at that time is reflected as a reduction of cash flow from operating activities.

Due to the variability in the future payments under the plan, the Trust estimates that between $16.8 million and $56.9 million will be paid out from 2009 through 2012 based on the current trust unit price, distribution levels and the Trust's market performance relative to its peers.

Interest Expense
Interest expense decreased to $5.8 million in the first quarter of 2009 from $8.8 million in 2008 due to a decrease in short-term interest rates. As at March 31, 2009, the Trust had $703.8 million of debt outstanding, of which $267.2 million was fixed at a weighted average rate of 5.1 per cent and $436.6 million, including the working capital facility, was floating at current market rates plus a credit spread of 60 basis points. Seventy-two per cent (US $404.5 million) of the Trust's debt is denominated in U.S. dollars.

Foreign Exchange Gains and Losses
The Trust recorded a loss of $14.6 million in the first quarter of 2009 on foreign exchange transactions compared to a loss of $15 million in 2008. These amounts include both realized and unrealized foreign exchange gains and losses.

Realized foreign exchange gains or losses arise from U.S. denominated transactions such as interest payments, debt repayments and hedging settlements. The 2009 realized foreign exchange loss of $0.2 million relates to interest payments and hedging settlements in the quarter.

Unrealized foreign exchange gains and losses are due to revaluation of U.S. denominated debt balances. The volatility of the Canadian dollar during the reporting period has a direct impact on the unrealized component of the foreign exchange gain or loss. The unrealized gain or loss impacts net income but does not impact cash flow from operating activities as it is a non-cash amount. From December 31, 2008 to March 31, 2009, the Cdn$/US$ exchange rate increased from 1.22 to 1.26 resulting in an unrealized loss of $14.4 million on U.S. dollar denominated debt.

Taxes
In the first quarter of 2009, a future income tax recovery of $12.2 million was included in income compared to an expense of $0.5 million in 2008.

The corporate income tax rate applicable to 2009 is 29 per cent; however the Trust and its subsidiaries did not pay any material cash income taxes for the first quarter of 2009. Due to the Trust's structure, currently, both income tax and future tax liabilities are passed on to the unitholders by means of royalty payments made between ARC Resources and the Trust.

Management and the Board of Directors continue to review the impact of the SIFT rules on our business strategy and while there has not been a final decision as to ARC's future direction at this time we are of the opinion that the conversion from a trust to a corporation may be the most logical and tax efficient alternative for ARC unitholders.

A conversion to a corporation will require approval of ARC's unitholders, as well as customary court and regulatory approvals. We currently anticipate that the closing of a conversion would occur on or before December 31, 2010. This would require a unitholder meeting to be scheduled for early to mid-December 2010. To be implemented, a conversion must be approved by not less than two-thirds of the votes cast by unitholders voting at the meeting. The intention would be for a conversion to be tax deferred for Canadian and U.S. income tax purposes.

For Canadian GAAP, we anticipate that the conversion would be accounted for on a continuity of interests basis. Under the continuity of interests method of accounting, the corporation would be recognized as the successor entity to the Trust and the consolidated financial statements would reflect financial position, results of operations and cash flows as if the corporation had always carried on the business formerly carried on by the Trust. Certain terms such as shareholder, unitholder, dividend, and distribution would be used interchangeably throughout the consolidated financial statements.

The corporation would expect to allocate its cash flow among funding a portion of capital expenditures, periodic debt repayments, site reclamation expenditures, and dividends, or distributions. Current taxes payable by ARC after converting to a corporation will be subject to normal corporate tax rates. Taxable income as a corporation will vary depending on total income and expenses and vary with changes to commodity prices, costs, claims for both accumulated tax pools and tax pools associated with current year expenditures. As ARC has accumulated $2.1 billion of income tax pools, taxable income will be reduced or potentially eliminated for the initial period post conversion. The $2 billion of income tax pools (detailed in Table 19) are deductible at various rates and annual deductions associated with the initial tax pools will decline over time.

Table 19

Tax Pool type	Cdn $ millions at March 31, 2009	Annual deductibility
Canadian Oil and Gas Property Expense	985.8	10% declining balance
Canadian Development Expense	387.8	30% declining balance
Canadian Exploration Expense	46.8	100%
Un-depreciated Capital Cost	418.1	Primarily 25% declining balance
Non-Capital Losses	136.6	100%
Research and Experimental credits	0.2	100%
Other	18.6	Various rates, 7% declining balance to 20%
Total Federal Tax Pools	**1,993.9**	
Additional Alberta Tax Pools	155.9	Various rates, 25% declining balance to 100%
Total Federal and Provincial Pools	**2,149.8**	

Returns to shareholders post conversion will be impacted by the reduction of cash flow required to pay current income taxes, if any. Over the longer term, we would expect Canadian investors who hold their trust units in a taxable account will be relatively indifferent on an after tax basis as to whether ARC is structured as a corporation or as a trust in 2011. However, Canadian tax deferred investors (those holding their trust units in a tax deferred vehicle such as an RRSP, RRIF or pension plan) and foreign investors will realize a lower after tax return on distributions in 2011 due to the introduction of the SIFT Tax should ARC stay as a trust, and their inability to claim the dividend tax credit if ARC converts to a corporation.

If a conversion from the trust structure to a Corporation is approved by the unitholders, the income tax payable by unitholders will vary and each unitholder should consult their own tax advisor for details on the direct impact to themselves.

Depletion, Depreciation and Accretion of Asset Retirement Obligation

The depletion, depreciation and accretion ("DD&A") rate increased to $16.68 per boe in the first quarter of 2009 from $15.92 per boe in 2008. The Trust posted a large increase in proved reserves at year-end 2008; however, these reserves were offset by a significant increase in the future development costs required to convert proven undeveloped reserves to proven producing reserves.

A breakdown of the DD&A rate is summarized in Table 20:

Table 20

	Three Months Ended March 31		
DD&A Rate ($ millions except per boe amounts)	**2009**	2008	% Change
Depletion of oil & gas assets (1)	**95.1**	94.7	-
Accretion of asset retirement obligation (2)	**2.3**	2.3	-
Total DD&A	**97.4**	97.0	-
DD&A rate per boe	**16.68**	15.92	5%

(1) Includes depletion of the capitalized portion of the asset retirement obligation that was capitalized to the PP&E balance and is being depleted over the life of the reserves.
(2) Represents the accretion expense on the asset retirement obligation during the year.

Capital Expenditures and Net Acquisitions

Total capital expenditures, excluding acquisitions and dispositions, totaled $97.2 million in the first quarter of 2009 compared to $111.3 million in the same period of 2008. This amount was incurred on drilling and completions, geological, geophysical and facilities expenditures.

During the first quarter of 2009, the Trust drilled 81 gross wells on operated properties, 56 of which were completed in the quarter in addition to six wells that were drilled in the fourth quarter of 2008.

In addition to capital expenditures on development activities, the Trust completed net property acquisitions of $6.2 million in the first quarter of 2009 most of which related to the acquisition of undeveloped land in the Dawson area.

For the remainder of 2009, the Trust expects to drill 41 gross wells on operated properties, complete all wells in inventory and construct a substantial portion of the Dawson gas plant that is now expected to be on stream by the end of the first quarter of 2010. Total capital expenditures are forecast to be $350 million in 2009.

A breakdown of capital expenditures and net acquisitions is shown in Table 21:

Table 21

	Three Months Ended March 31		
Capital Expenditures ($ millions)	**2009**	2008	% Change
Geological and geophysical	**2.8**	5.5	(49)
Drilling and completions	**68.5**	64.4	6
Plant and facilities	**25.1**	11.6	116
Undeveloped land purchased at crown land sales	**0.2**	28.8	(99)
Other capital	**0.6**	1.0	(40)
Total capital expenditures before net acquisitions	**97.2**	111.3	(13)
Producing property acquisitions [1]	**0.1**	-	100
Undeveloped land property acquisitions	**6.1**	13.9	(56)
Producing property dispositions [1]	**-**	(0.2)	(100)
Undeveloped land property dispositions	**-**	(3.6)	(100)
Total capital expenditures and net acquisitions	**103.4**	121.4	(15)

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

Approximately 45 per cent of the $97.2 million capital program in the first quarter of 2009 was financed with cash flow from operating activities compared to 72 per cent in for the same period of 2008. Property acquisitions were financed through debt and working capital.

Table 22

Source of Funding of Capital Expenditures and Net Acquisitions
($ millions)

	Three Months Ended March 31, 2009			Three Months Ended March 31, 2008		
	Development Capital	**Net Acquisitions**	**Total Expenditures**	Development Capital	Net Acquisitions	Total Expenditures
Expenditures	**97.2**	**6.2**	**103.4**	111.3	10.1	121.4
Per cent funded by:						
Cash flow from operating activities	**45%**	**-**	**42%**	72%	-	66%
Proceeds from Distribution re-investment plan (“DRIP”)	**19%**	**-**	**18%**	25%	-	23%
Debt	**36%**	**100%**	**40%**	3%	100%	11%
	100%	**100%**	**100%**	100%	100%	100%

Asset Retirement Obligation and Reclamation Fund

At March 31, 2009, the Trust recorded an Asset Retirement Obligation (“ARO”) of $142.5 million ($141.5 million at December 31, 2008) for future abandonment and reclamation of the Trust’s properties.

Included in the March 31, 2009 ARO balance was a $0.4 million increase related to development activities in the first three months of 2009, $2.3 million for accretion expense in the period and a reduction of $1.7 million for actual abandonment expenditures incurred in the first quarter of 2009.

ARC’s reclamations funds held $26.6 million as at March 31, 2009. Under the terms of the Trust’s investment policy, reclamation fund investments and excess cash can only be invested in Canadian or U.S. Government securities, investment grade corporate bonds, or investment grade short-term money market securities.

Capitalization, Financial Resources and Liquidity

A breakdown of the Trust’s capital structure is outlined in Table 23, as at March 31, 2009 and December 31, 2008:

Table 23

Capital Structure and Liquidity ($ millions except per cent and ratio amounts)	**March 31, 2009**	December 31, 2008
Net debt obligations (1)	**781.5**	961.9
Market value of trust units and exchangeable shares (2)	**3,339.4**	4,405.9
Total capitalization (3)	**4,120.9**	5,367.8
Net debt as a percentage of total capitalization	**19.0%**	17.9%
Net debt to annualized YTD cash flow from operating activities	**1.6**	1.0

(1) Net debt is a non-GAAP measure and therefore it may not be comparable with the calculation of similar measures for other entities. It is calculated as long-term debt plus current liabilities less the current assets as they appear on the Consolidated Balance Sheets. Net debt excludes current unrealized amounts pertaining to risk management contracts and the current portion of future income taxes.

(2) Calculated using the total trust units outstanding at March 31 and December 31 including the total number of trust units issuable for exchangeable shares at March 31 and December 31 multiplied by the closing trust unit price of $14.15 and $20.10 at March 31, 2009 and December 31, 2008, respectively.

(3) 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.

At March 31, 2009, the Trust's current credit facilities comprised US$212 million in senior secured notes currently outstanding, a Cdn$800 million syndicated bank credit facility, of which $434.5 million was outstanding and a Cdn$25 million demand working capital facility, of which $2.1 million was outstanding. The credit facility syndicate includes 11 domestic and international banks. The Trust's debt agreements contain a number of covenants all of which were met as at March 31, 2009; these agreements are available at www.SEDAR.com. The major financial covenants are described below:

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

On April 14, 2009, the Trust announced the closing of a private placement of long-term debt in the form of senior secured notes totaling US$125 million at a blended average interest rate of 7.47 per cent. The notes were offered in three tranches, one tranche of US$67.5 million senior notes with a five year average life repayable in years 2012 through 2016 issued at an interest rate of 7.19 per cent. The second tranche of US$35 million senior notes with a 10 year average life repayable in years 2017 through 2021, issued at an interest rate of 8.21 per cent. The third tranche of Cdn$29 million senior notes was issued with a five year average life repayable in years 2012 through 2016, issued at an interest rate of 6.5 per cent.

In April 2009, ARC also extended its uncommitted master shelf agreement from May 2009 to April 2012. The extended agreement allows for an aggregate draw of up to US$225 million (Cdn$283.5 million) in long term notes at a rate equal to the related U.S. treasuries corresponding to the term of the notes plus an appropriate credit risk adjustment at the time of issuance.

As at the date of this MD&A, the Trust has approximately $610 million of unused credit available: $445 million under its credit facility, and $165 million available to draw long term notes under the master shelf agreement.

As a result of the weakened global economic situation, the Trust along with all other oil and gas entities will have restricted access to capital and increased borrowing costs. Although the Trust's business and asset base have not changed, the lending capacity of all financial institutions has been diminished and risk premiums have increased. These issues will impact the Trust as it reviews financing alternatives for the 2009 capital program, assesses potential future acquisition opportunities and manages future cash flow decremented by lower commodity prices and higher borrowing costs. The Trust intends to finance its 2009 capital program with cash flow, existing credit facilities, proceeds from the DRIP, potential asset dispositions and new borrowings or equity if necessary. Beyond that, the Trust may need to access additional capital and/or curtail capital expenditure plans and will look to do so in the most cost effective manner possible.

Unitholders' Equity
At March 31, 2009, there were 236 million trust units issued and issuable for exchangeable shares, an increase of 16.8 million trust units from December 31, 2008.

On February 6, 2009, the Trust closed its previously announced equity offering for 15 million trust units. The gross proceeds raised under this offering were $253 million and proceeds net of underwriter and transaction fees were approximately $240 million. The proceeds were used to reduce outstanding indebtedness under the Trust's credit facility.

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. During the first quarter of 2009, the Trust raised proceeds of $18.7 million and issued 1.3 million trust units pursuant to the DRIP at an average price of $14.75 per unit.

Distributions
ARC declared distributions of $82 million ($0.36 per unit), representing 66 per cent of 2009 first quarter cash flow from operating activities compared to distributions of $126.8 million ($0.60 per unit) representing 60 per cent of cash flow from operating activities in the first quarter of 2008.

As a result of the current commodity price environment, the monthly distribution has decreased from $0.12 per unit to $0.10 per unit starting with the distribution declared for the month of May and payable on June 15, 2009. The decrease in distributions will provide the Trust with greater financial flexibility to execute strategic capital projects while maintaining a conservative debt balance and strong balance sheet.

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

- The portion of capital expenditures that are funded with cash flow from operating activities. In the first quarter of 2009, the Trust withheld 34 per cent of cash flow from operating activities to fund 45 per cent of the capital program excluding acquisitions. The remaining portion of capital expenditures was financed by proceeds from the DRIP program and debt.

- An annual contribution to the reclamation funds, with $12 million scheduled to be contributed in 2009. The reclamation funds are segregated bank accounts or subsidiary trusts and the balances will be drawn on in future periods as the Trust incurs abandonment and reclamation costs over the life of its properties.

- Debt principal repayments from time to time as determined by the board of directors. The Trust's current debt level is well within the covenants specified in the debt agreements and, accordingly, there are no current mandatory requirements for repayment. Refer to the "Capital Structure and Liquidity" section of this MD&A for a detailed review of the debt covenants.

- Income taxes that are not passed on to unitholders. The Trust has a liability for future income taxes due to the excess of book value over the tax basis of the assets of the Trust and its corporate subsidiaries. The Trust currently, and up until January 1, 2011, may minimize or eliminate cash income taxes in corporate subsidiaries by maximizing deductions, however in future periods there may be cash income taxes if deductions are not sufficient to eliminate taxable income. Taxability of the Trust is currently passed on to unitholders in the form of taxable distributions whereby corporate income taxes are eliminated at the Trust level. The Trust taxation legislation, which will take effect in 2011, will result in taxes payable at the Trust level and therefore distributions to unitholders will decrease.

- Working capital requirements as determined by the board of directors. Certain working capital amounts may be deducted from cash flow from operating activities, however such amounts would be minimal and the Trust does not anticipate any such deductions in the foreseeable future.

- The Trust has certain obligations for future payments relative to employee long-term incentive compensation. Presently, the Trust estimates that $16.8 million to $56.9 million will be paid out pursuant to such commitments in 2009 through 2012 subject to vesting provisions and future performance of the Trust. These amounts will reduce cash flow from operating activities and may in turn reduce distributions in future periods.

Cash flow from operating activities and distributions in total and per unit are summarized in Table 24:

Table 24

Cash flow from operating activities and distributions	Three Months Ended March 31			Three Months Ended March 31		
	2009	2008	% Change	**2009**	2008	% Change
	($ millions)			($ per unit)		
Cash flow from operating activities	**124.3**	209.9	(41)	**0.54**	0.98	(45)
Net reclamation fund withdrawals (contributions) (1)	**1.5**	(3.3)	145	**0.01**	(0.02)	150
Capital expenditures funded with cash flow from operating activities	**(43.8)**	(79.8)	(45)	**(0.19)**	(0.37)	(49)
Other (2)	**-**	-	-	**-**	0.01	(100)
Distributions	**82.0**	126.8	(35)	**0.36**	0.60	(40)

(1) Includes interest income earned on the reclamation fund balances that is retained in the reclamation funds.
(2) Other represents the difference due to distributions paid being based on actual trust units outstanding at each distribution date whereas per unit cash flow from operating activities, reclamation fund contributions and capital expenditures funded with cash flow from operated activities are based on weighted average outstanding trust units in the period.

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

- To maintain a level of distributions that, in normal times, in the opinion of Management and the Board of Directors, is sustainable for a minimum period of six months after factoring in the impact of current commodity prices on cash flows. The Trust's objective is to normalize the effect of volatility of commodity prices rather than to pass on that volatility to unitholders in the form of fluctuating monthly distributions.

- To ensure that the Trust's financial flexibility is maintained by a review of the Trust's debt to equity and debt to cash flow from operating activities levels. The use of cash flow from operating activities and proceeds from equity offerings to fund capital development activities reduces the requirements of the Trust to use debt to finance these expenditures. In the first quarter of 2009 the Trust funded 45 per cent of capital development activities with a portion of cash flow from operating activities. Distributions and the actual amount of cash flows withheld to fund the Trust's capital expenditure program is dependent on the commodity price environment and is subject to the approval and discretion of the Board of Directors.

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

Please refer to the Trust's website at www.arcenergytrust.com for details monthly distribution amounts and distribution dates for 2009.

Environmental Initiatives Impacting the Trust
In March of 2009, ARC was selected to receive a portion of the required funding for the next two phases of its Heartland Area Redwater Project ("HARP") from the ecoENERGY Technology Initiative of the Federal Government of Canada. This project is designed to demonstrate the feasibility of safe CO_2 storage in the Redwater Leduc Reef saline water formation, situated northeast of Edmonton, Alberta. This site is located close to the Alberta Industrial Heartland region, where there are a number of large industrial sources of greenhouse gas ("GHG") emissions, including chemical and fertilizer plants and several oil sands upgraders that are operating, being built or in the planning stages.

The Redwater Leduc Reef is also strategically located along a straight-line path between Fort McMurray and Edmonton, a potential route for a CO_2 pipeline from Fort McMurray. Preliminary work estimates the total storage capacity of the saline water formation portion of the reef to be one gigatonne of CO_2.

Over the long term, this project will demonstrate the prospect of carbon capture and storage on a commercial scale (several million tonnes per year), contributing to a significant reduction in GHG emissions.

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 and employee agreements. These obligations are of a recurring and consistent nature and impact the Trust's cash flows in an ongoing manner. The Trust also has contractual obligations and commitments that are of a less routine nature as disclosed in Table 25.

Table 25

	Payments due by period				
	2009	2010-2011	2012-2013	Thereafter	Total
Debt repayments (1)	22.8	492.0	81.4	107.6	703.8
Interest payments (2)	11.8	22.9	15.9	10.2	60.8
Reclamation fund contributions (3)	5.3	9.5	8.3	67.9	91.0
Purchase commitments	8.0	13.0	7.1	5.1	33.2
Transportation commitments (4)	-	14.9	21.9	21.0	57.8
Operating leases	5.7	9.8	14.3	81.8	111.6
Risk management contract premiums (5)	14.1	-	-	-	14.1
Total contractual obligations	67.7	562.1	148.9	293.6	1,072.3

(1) Long-term and short-term debt, excluding interest.
(2) Fixed interest payments on senior secured notes.
(3) Contribution commitments to a restricted reclamation fund associated with the Redwater property.
(4) Fixed payments for transporting production from the Dawson gas plant, expected to be operational in early 2010.
(5) Fixed premiums to be paid in future periods on certain commodity risk management contracts.

The above noted risk management contract premiums are part of the Trust's commitments related to its risk management program and have been recorded at fair market value at March 31, 2009 on the balance sheet as part of risk management contracts. In addition to the premiums, the Trust has commitments related to its risk management program.

The Trust enters into commitments for capital expenditures in advance of the expenditures being made. At a given point in time, it is estimated that the Trust has committed to capital expenditures equal to approximately one quarter of its capital budget by means of giving the necessary authorizations to incur the capital in a future period. The Trust's 2009 capital budget has been approved by the Board at $350 million. This commitment has not been disclosed in the commitment table (Table 25) as it is of a routine nature and is part of normal course of operations for active oil and gas companies and trusts.

The 2009 capital budget of $350 million includes $11 million for leasehold development costs related to the Trust's new office space in downtown Calgary. These costs will be incurred throughout 2009 with additional costs to be incurred in 2010. The operating lease commitments for the new space begin in the first quarter of 2010 and are included in Table 25.

The Trust is involved in litigation and claims arising in the normal course of operations. Management is of the opinion that pending litigation will not have a material adverse impact on the Trust's financial position or results of operations and therefore the commitment table (Table 25) does not include any commitments for outstanding litigation and claims.

The Trust has certain sales contracts with aggregators whereby the price received by the Trust is dependent upon the contracts entered into by the aggregator. This commitment has not been disclosed in the commitment table (Table 25) as it is of a routine nature and is part of normal course of operations.

Off Balance Sheet Arrangements
The Trust has certain lease agreements, all of which are reflected in the Contractual Obligations and Commitments table (Table 25), which were entered into in the normal course of operations. All leases have been treated as operating leases whereby the lease payments are included in operating expenses or G&A expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases in the balance sheet as of March 31, 2009.

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

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

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

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

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

Internal Control over Financial Reporting
ARC is required to comply with National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings", otherwise referred to as Canadian SOX ("C-Sox"). The certification of interim filings for the interim period ended March 31, 2009 requires that the Trust disclose in the interim MD&A any changes in the Trust's internal control over financial reporting that occurred during the period that has materially affected, or is reasonably likely to materially affect the Trust's internal control over financial reporting. The Trust confirms that no such changes were made to the internal controls over financial reporting during the first three months of 2009.

Financial Reporting Update
Current Year Accounting Changes

Effective January 1, 2009, the Trust prospectively adopted Section 3064, Goodwill and Intangible Assets issued by the Canadian Institute of Chartered Accountants ("CICA"). Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. This new section has no current impact on the Trust or its Consolidated Financial Statements.

Future Accounting Changes

International Financial Reporting Standards ("IFRS")
In April 2008, the CICA published the exposure draft "Adopting IFRSs in Canada". The exposure draft proposes to incorporate IFRSs into the CICA Accounting Handbook effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. At this date, publicly accountable enterprises will be required to prepare financial statements in accordance with IFRSs. The Trust is currently reviewing the standards to determine the potential impact on its Consolidated Financial Statements. The Trust has appointed internal staff to lead the conversion project along with sponsorship from the senior leadership team. In addition, an external advisor has been retained to assist the Trust in scoping its conversion project. The Trust has performed a diagnostic analysis that identifies differences between the Trust's current accounting policies and IFRSs. The Trust has evaluated the impact of these differences and is developing accounting policies in order to comply with IFRS.

Non-GAAP Measures
Management uses certain key performance indicators ("KPIs") and industry benchmarks such as distributions as a per cent of cash flow from operating activities, operating netbacks ("netbacks"), total capitalization, finding, development and acquisition costs, recycle ratio, reserve life index, reserves per unit and production per unit, net asset value and total returns to analyze financial and operating performance. Management feels that these KPIs and benchmarks are key measures of profitability and overall sustainability for the Trust. These KPIs 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.

Forward-looking Information and Statements
This news release contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "strategy" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this news release contains forward-looking information and statements pertaining to the following: the volumes and estimated value of ARC's oil and gas reserves; the life of ARC's reserves; the volume and product mix of ARC's oil and gas production; future oil and natural gas prices and ARC's commodity risk management programs; the amount of future asset retirement obligations; future liquidity and financial capacity; future results from operations and operating metrics; future costs, expenses and royalty rates; future interest costs; future development, exploration, acquisition and development activities (including drilling plans) and related capital expenditures, future tax treatment of income trusts and future taxes payable by ARC; and ARC's tax pools.

The forward-looking information and statements contained in this news release reflect several material factors and expectations and assumptions of ARC including, without limitation: that ARC will continue to conduct its operations in a manner consistent with past operations; the general continuance of current industry conditions; the continuance of existing (and in certain circumstances, the implementation of proposed) tax, royalty and regulatory regimes; the accuracy of the estimates of ARC's reserves and resource volumes; certain commodity price and other cost assumptions; and the continued availability of adequate debt and equity financing and cash flow to fund its planned expenditures; ARC believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information and statements included in this news release are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; changes in the demand for or supply of ARC's products; unanticipated operating results or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in development plans of ARC or by third party operators of ARC's properties, increased debt levels or debt service requirements; inaccurate estimation of ARC's oil and gas reserve and resource volumes; limited, unfavorable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; and certain other risks detailed from time to time in ARC's public disclosure documents (including, without limitation, those risks identified in this news release and in ARC's Annual Information Form).

The forward-looking information and statements contained in this news release speak only as of the date of this news release, and none of ARC or its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable laws.

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

QUARTERLY HISTORICAL REVIEW

(Cdn $ millions, except per unit amounts)	2009		2008				2007	
FINANCIAL	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Revenue before royalties	**225.2**	300.8	485.7	512.0	407.9	338.0	300.2	305.6
Per unit [1]	**0.98**	1.38	2.24	2.38	1.91	1.59	1.42	1.46
Cash flow from operating activities [2]	**124.3**	209.4	251.4	273.4	209.9	173.7	179.6	179.4
Per unit – basic [1]	**0.54**	0.96	1.16	1.27	0.98	0.82	0.85	0.86
Per unit - diluted	**0.54**	0.96	1.16	1.27	0.98	0.82	0.85	0.86
Net income	**22.3**	82.7	311.7	57.3	81.3	106.3	120.8	184.9
Per unit – basic [3]	**0.10**	0.38	1.46	0.27	0.39	0.51	0.58	0.90
Per unit - diluted	**0.10**	0.38	1.46	0.27	0.38	0.51	0.58	0.89
Distributions	**82.0**	127.2	171.3	144.7	126.8	125.8	125.0	124.1
Per unit – basic [4]	**0.36**	0.59	0.80	0.68	0.60	0.60	0.60	0.60
Total assets	**3,733.1**	3,766.7	3,687.5	3,664.3	3,592.6	3,533.0	3,460.8	3,432.8
Total liabilities	**1,392.1**	1,624.6	1,530.8	1,689.6	1,560.4	1,491.3	1,421.4	1,415.3
Net debt outstanding [5]	**781.5**	961.9	773.2	756.1	770.1	752.7	699.8	653.9
Weighted average trust units [6]	**228.9**	218.3	216.6	215.2	213.8	212.5	210.9	209.5
Trust units outstanding and issuable [6]	**236.0**	219.2	217.4	215.8	214.7	213.2	211.7	210.2
CAPITAL EXPENDITURES								
Geological and geophysical	**2.8**	3.7	1.3	16.4	5.5	3.0	2.9	4.1
Land	**0.2**	17.1	18.6	57.8	28.8	42.6	33.0	1.7
Drilling and completions	**68.5**	117.1	91.4	32.6	64.4	75.2	73.4	25.8
Plant and facilities	**25.1**	30.5	24.2	24.1	11.6	17.9	21.1	16.3
Other capital	**0.6**	1.0	0.9	0.4	1.0	0.6	1.5	0.6
Total capital expenditures	**97.2**	169.4	136.4	131.3	111.3	139.3	131.9	48.5
Property acquisitions (dispositions) net	**6.2**	27.6	13.1	0.3	10.1	5.0	27.3	10.0
Total capital expenditures and net acquisitions	**103.4**	197.0	149.5	131.6	121.4	144.3	159.2	58.5
OPERATING								
Production								
Crude oil (bbl/d)	**28,806**	28,935	28,509	27,541	29,064	28,682	28,437	28,099
Natural gas (mmcf/d)	**193.8**	195.1	192.0	194.7	204.3	187.4	173.3	176.7
Natural gas liquids (bbl/d)	**3,764**	3,858	3,822	3,906	3,856	4,067	3,795	4,088
Total (boe per day 6:1)	**64,872**	65,313	64,325	63,896	66,976	63,989	61,108	61,637
Average prices								
Crude oil ($/bbl)	**46.44**	56.26	114.20	118.32	89.72	77.53	73.40	65.21
Natural gas ($/mcf)	**5.20**	7.48	8.68	10.41	7.80	6.32	5.52	7.38
Natural gas liquids ($/bbl)	**38.86**	45.22	82.87	82.29	68.54	62.75	55.64	52.76
Oil equivalent ($/boe)	**38.40**	49.93	81.42	87.73	66.67	57.26	53.28	54.37
TRUST UNIT TRADING								
(based on intra-day trading) unit prices								
High	**20.90**	22.55	33.30	33.95	27.06	21.55	22.60	23.86
Low	**11.73**	15.01	22.33	25.19	20.00	18.90	19.00	20.78
Close	**14.15**	20.10	23.10	33.95	26.38	20.40	21.17	21.74
Average daily volume (thousands)	**1,240**	1,523	841	659	863	624	503	599

(1) Per unit amounts (with the exception of per unit distributions) are based on weighted average trust units outstanding plus trust units issuable for exchangeable shares.
(2) This is a GAAP measure and a change from the non-GAAP measure reported in prior reports. Refer to non-GAAP section.
(3) Net income per unit is based on net income after non-controlling interest divided by weighted average trust units outstanding (excluding trust units issuable for exchangeable shares).
(4) Based on number of trust units outstanding at each distribution date.
(5) Net debt excludes the current unrealized risk management contracts asset and liability and the current portion of future income taxes.
(6) Includes trust units issuable for outstanding exchangeable shares based on the period end exchange ratio.

CONSOLIDATED BALANCE SHEETS (unaudited)
As at March 31 and December 31

(Cdn$ millions)		**2009**		2008
ASSETS				
Current assets				
Cash and cash equivalents (Note 3)	**$**	**-**	$	40.0
Accounts receivable (Note 4)		**125.1**		110.0
Prepaid expenses		**17.7**		16.8
Risk management contracts (Notes 4 and 9)		**13.9**		24.4
Future income taxes		**4.0**		3.9
		160.7		195.1
Reclamation funds		**26.6**		28.2
Risk management contracts (Notes 4 and 9)		**3.0**		9.2
Property, plant and equipment		**3,385.2**		3,376.6
Goodwill		**157.6**		157.6
Total assets	**$**	**3,733.1**	$	3,766.7
LIABILITIES				
Current liabilities				
Accounts payable and accrued liabilities (Note 5)	**$**	**192.4**	$	194.4
Distributions payable		**28.1**		32.5
Risk management contracts (Notes 4 and 9)		**18.8**		23.5
		239.3		250.4
Risk management contracts (Notes 4 and 9)		**1.0**		3.4
Long-term debt (Note 6)		**703.8**		901.8
Accrued long-term incentive compensation (Note 14)		**7.0**		14.2
Asset retirement obligations (Note 7)		**142.5**		141.5
Future income taxes		**298.5**		313.3
Total liabilities		**1,392.1**		1,624.6
COMMITMENTS AND CONTINGENCIES (Note 15)				
NON-CONTROLLING INTEREST				
Exchangeable shares (Note 10)		**36.4**		42.4
UNITHOLDERS' EQUITY				
Unitholders' capital (Note 11)		**2,867.6**		2,600.7
Deficit (Note 12)		**(562.6)**		(502.9)
Accumulated other comprehensive (loss) income (Note 12)		**(0.4)**		1.9
Total unitholders' equity		**2,304.6**		2,099.7
Total liabilities and unitholders' equity	**$**	**3,733.1**	$	3,766.7

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF INCOME AND DEFICIT (unaudited)

For the three months ended March 31

(Cdn$ millions, except per unit amounts)		2009		2008
REVENUES				
Oil, natural gas and natural gas liquids	**$**	**225.2**	$	407.9
Royalties		**(37.0)**		(72.2)
		188.2		335.7
Gain (loss) on risk management contracts (Note 9)				
Realized		**16.3**		(29.5)
Unrealized		**(6.6)**		(18.7)
		197.9		287.5
EXPENSES				
Transportation		**5.6**		4.4
Operating		**59.1**		58.2
General and administrative		**5.1**		21.2
Interest on long-term debt (Note 6)		**5.8**		8.8
Depletion, depreciation and accretion		**97.4**		97.0
Loss on foreign exchange		**14.6**		15.0
		187.6		204.6
Future income tax recovery (expense)		**12.2**		(0.5)
Net income before non-controlling interest		**22.5**		82.4
Non-controlling interest (Note 10)		**(0.2)**		(1.1)
Net income	**$**	**22.3**	$	81.3
Deficit, beginning of period	**$**	**(502.9)**	$	(465.9)
Distributions paid or declared (Note 13)		**(82.0)**		(126.8)
Deficit, end of period (Note 12)	**$**	**(562.6)**	$	(511.4)
Net income per unit (Note 11)				
Basic	**$**	**0.10**	$	0.39
Diluted	**$**	**0.10**	$	0.39

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME AND ACCUMULATED OTHER COMPREHENSIVE INCOME (unaudited)

For the three months ended March 31

(Cdn$ millions)		**2009**		2008
Net income	$	**22.3**	$	81.3
Other comprehensive (loss) income, net of tax				
Losses on financial instruments designated as cash flow hedges (1)		**(2.1)**		(2.9)
De-designation of cash flow hedge (2) (Note 9)		**-**		10.0
Gains and losses on financial instruments designated as cash flow hedges in prior periods realized in net income in the current period (3) (Note 9)		**(0.1)**		(0.4)
Net unrealized (losses) gains on available-for-sale reclamation funds' investments (4)		**(0.1)**		0.2
Other comprehensive (loss) income		**(2.3)**		6.9
Comprehensive income	$	**20.0**	$	88.2
Accumulated other comprehensive income (loss), beginning of period		**1.9**		(2.9)
Other comprehensive (loss) income		**(2.3)**		6.9
Accumulated other comprehensive (loss) income, end of period (Note 12)	$	**(0.4)**	$	4.0

(1) Amounts are net of tax of $0.7 million for the period ended March 31, 2009 (net of tax of $1.1 million for the period ended March 31, 2008).
(2) Amounts are net of tax of $3.6 million for the period ended March 31, 2008.
(3) Nominal future income tax impact for the period ended March 31, 2009 (net of tax of $0.1 million for the period ended March 31, 2008).
(4) Nominal future income tax impact for the period ended March 31, 2009 (net of tax of $0.1 million for the period ended March 31, 2008).

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

For the three months ended March 31

(Cdn$ millions)		2009		2008
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	**$**	**22.3**	$	81.3
Add items not involving cash:				
Non-controlling interest (Note 10)		**0.2**		1.1
Future income tax (recovery) expense		**(12.2)**		0.5
Depletion, depreciation and accretion		**97.4**		97.0
Non-cash loss on risk management contracts (Note 9)		**6.6**		18.7
Non-cash loss on foreign exchange		**14.4**		15.0
Non-cash trust unit incentive compensation (recovery) expense (Note 14)		**(12.1)**		13.8
Expenditures on site restoration and reclamation (Note 7)		**(1.7)**		(3.7)
Change in non-cash working capital		**9.4**		(13.8)
		124.3		209.9
CASH FLOWS FROM FINANCING ACTIVITIES				
Repayment of long-term debt under revolving credit facilities, net		**(212.4)**		(9.3)
Issue of trust units		**253.5**		2.8
Trust unit issue costs		**(12.9)**		-
Cash distributions paid (Note 13)		**(68.2)**		(101.3)
Change in non-cash working capital		**1.9**		0.9
		(38.1)		(106.9)
CASH FLOWS FROM INVESTING ACTIVITIES				
Acquisition of petroleum and natural gas properties		**(6.2)**		(10.1)
Proceeds on disposition of petroleum and natural gas properties		**-**		0.1
Capital expenditures		**(99.3)**		(109.4)
Net reclamation fund withdrawals		**1.5**		0.2
Change in non-cash working capital		**(22.2)**		11.6
		(126.2)		(107.6)
DECREASE IN CASH AND CASH EQUIVALENTS		**(40.0)**		(4.6)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		**40.0**		7.0
CASH AND CASH EQUIVALENTS, END OF PERIOD	**$**	**-**	$	2.4

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

March 31, 2009 and 2008
(all tabular amounts in Cdn$ millions, except per unit 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, except as highlighted in Note 2. The interim consolidated financial statement note disclosures do not include all of those required by Canadian generally accepted accounting principles ("GAAP") applicable for annual consolidated financial statements. Accordingly, these interim consolidated financial statements should be read in conjunction with the audited consolidated financial statements included in the Trust's 2008 annual report.

2. NEW ACCOUNTING POLICIES

Current Year Accounting Changes

Effective January 1, 2009, the Trust adopted Section 3064, Goodwill and Intangible Assets issued by the Canadian Institute of Chartered Accountants ("CICA"). Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. This new section has no current impact on the Trust or its consolidated financial statements.

This standard was adopted prospectively.

Future Accounting Changes

International Financial Reporting Standards ("IFRS")
In April 2008, the CICA published the exposure draft "Adopting IFRSs in Canada". The exposure draft proposes to incorporate IFRSs into the CICA Accounting Handbook effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. At this date, publicly accountable enterprises will be required to prepare financial statements in accordance with IFRSs. The Trust is currently reviewing the standards to determine the potential impact on its Consolidated Financial Statements. The Trust has appointed internal staff to lead the conversion project along with sponsorship from the senior leadership team. In addition, an external advisor has been retained to assist the Trust in scoping its conversion project. The Trust has performed a diagnostic analysis that identifies differences between the Trust's current accounting policies and IFRSs. The Trust has evaluated the impact of these differences and is developing accounting policies in order to comply with IFRS.

3. CASH AND CASH EQUIVALENTS

Cash equivalents are nil as at March 31, 2009 ($40 million in Canadian Treasury Bills as at December 31, 2008).

4. FINANCIAL ASSETS AND CREDIT RISK

Credit risk is the risk of financial loss to the Trust if a partner or counterparty to a product sales contract or financial instrument fails to meet its contractual obligations. The Trust is exposed to credit risk with respect to its cash equivalents, accounts receivable, reclamation funds, and risk management contracts. Most of the Trust's accounts receivable relate to oil and natural gas sales and are subject to typical industry credit risks. The Trust manages this credit risk as follows:

- By entering into sales contracts with only established credit worthy counterparties as verified by a third party rating agency, through internal evaluation or by requiring security such as letters of credit;
- By limiting exposure to any one counterparty in accordance with the Trust's Credit Policy;
- By restricting cash equivalent investments, reclamation fund investments, and risk management transactions to counterparties that, at the time of transaction are not less than investment grade;

The majority of the credit exposure on accounts receivable at March 31, 2009 pertains to accrued revenue for March 2009 production volumes. The Trust transacts with a number of oil and natural gas marketing companies and commodity end users ("commodity purchasers"). Commodity purchasers typically remit amounts to the Trust by the 25th day of the month following production. Joint interest receivables are typically collected within one to three months following production. At March 31, 2009, no one counterparty accounted for more than 20 per cent of the total accounts receivable balance and the largest commodity purchaser receivable balance is 50 per cent secured with Letters of Credit.

During the first three months of 2009 the Trust did not record any provision for non-collectible accounts receivable. The Trust's allowance for doubtful accounts was $32 million as at March 31, 2009 and December 31, 2008.

When determining whether amounts that are past due are collectable, management assesses the creditworthiness and past payment history of the counterparty, as well as the nature of the past due amount. ARC considers all amounts greater than 90 days to be past due. As at March 31, 2009, $3.9 million of accounts receivable are past due, excluding amounts described above, all of which are considered to be collectable.

Maximum credit risk is calculated as the total recorded value of cash equivalents, accounts receivable, reclamation funds, and risk management contracts at the balance sheet date.

5. FINANCIAL LIABILITIES AND LIQUIDITY RISK

Liquidity risk is the risk that the Trust will not be able to meet its financial obligations as they become due. The Trust actively manages its liquidity through cash, distribution policy, and debt and equity management strategies. Such strategies include continuously monitoring forecasted and actual cash flows from operating, financing and investing activities, available credit under existing banking arrangements and opportunities to issue additional Trust units. Management believes that future cash flows generated from these sources will be adequate to settle the Trust's financial liabilities.

The following table details the Trust's financial liabilities as at March 31, 2009:

	1 year	**2 - 3 years**	**4 - 5 years**	**Beyond 5 years**	**Total**
Accounts payable and accrued liabilities (1)	198.9	-	-	-	198.9
Distributions payable (2)	22.5	-	-	-	22.5
Risk management contracts (3)	18.0	1.3	0.5	-	19.8
Senior secured notes and interest	33.8	79.9	97.0	117.3	328.0
Revolving credit facilities	-	436.6	-	-	436.6
Accrued long-term incentive compensation (1)	-	28.1	-	-	28.1
Total financial liabilities	273.2	545.9	97.5	117.3	1,033.9

(1) Liabilities under the Whole Unit Plan represent the total amount expected to be paid out on vesting.
(2) Amounts payable for the distribution represents the net cash payable after distribution reinvestment.
(3) Amounts payable for the risk management contracts have been included at their intrinsic value.

The Trust actively maintains credit and working capital facilities to ensure that it has sufficient available funds to meet its financial requirements at a reasonable cost. Refer to Note 6 for further details on available amounts under existing banking arrangements and Note 8 for further details on capital management.

6. LONG-TERM DEBT

		March 31, 2009		December 31, 2008
Revolving credit facilities				
Syndicated credit facility – Cdn$ denominated	**$**	**191.9**	$	399.5
Syndicated credit facility – US$ denominated		**242.6**		240.6
Working capital facility		**2.1**		2.1
Senior secured notes				
5.42% US$ Note		**94.5**		91.9
4.94% US$ Note		**15.1**		14.7
4.62% US$ Note		**78.8**		76.5
5.10% US$ Note		**78.8**		76.5
Total long-term debt outstanding	**$**	**703.8**	$	901.8

Revolving Credit Facilities

The Trust has an $800 million secured, annually extendible, financial covenant-based syndicated credit facility. The Trust also has in place a $25 million demand working capital facility. The working capital facility is secured and is subject to the same covenants as the syndicated credit facility.

Borrowings under the syndicated credit facility bear interest at bank prime (2.5 per cent at March 31, 2009, four per cent at December 31, 2008) or, at the Trust's option, Canadian dollar bankers' acceptances or U.S. dollar LIBOR loans, plus a stamping fee. At the option of the Trust, the lenders will review the syndicated credit facility each year and determine whether they will extend the revolving period for another year. In the event that the credit facility is not extended at anytime before the maturity date, the loan balance will become repayable on the maturity date. The maturity date of the current syndicated credit facility is April 15, 2011. All drawings under the facility are subject to stamping fees depending on the ratio of consolidated long-term debt and letters of credit to annualized net income before non-cash items and interest expense. These stamping fees vary between a minimum of 60 basis points ("bps") to a maximum of 110 bps.

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

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

In the event that the Trust enters into a material acquisition whereby the purchase price exceeds 10 per cent of the book value of the Trust's assets, the ratios in the first two covenants above are increased to 3.5 and 5.5 times respectively, while the third covenant is increased to 55 per cent for the subsequent six month period. As at March 31, 2009, the Trust had $1.9 million in letters of credit ($1.9 million in 2008), no subordinated debt, and was in compliance with all covenants.

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

During the first quarter of 2009, the weighted-average effective interest rate under the credit facility was 1.7 per cent (3.8 per cent in 2008).

Amounts of US$16.4 million due under the senior notes and $2.1 million due under the Trust's working capital facility in the next 12 months have not been included in current liabilities as management has the ability and intent to refinance this amount through the syndicated credit facility. The fair value of senior secured notes as at March 31, 2009 is $297.8 million ($289.9 million as at December 31, 2008), and is calculated as the present value of principal and interest payments discounted at the Trust's credit adjusted risk free rate.

Interest paid during the first quarter of 2009 was $1.4 million less than interest expense ($0.8 million less than interest expense in the first quarter of 2008).

On April 14, 2009, the Trust closed a private placement of long-term debt in the form of senior secured notes totaling US$125 million at a blended average interest rate of 7.47 per cent. The notes were offered in three tranches, one tranche of US$67.5 million senior notes with a five year average life repayable in years 2012 through 2016 issued at an interest rate of 7.19 per cent. The second tranche of US$35 million senior notes with a 10 year average life repayable in years 2017 through 2021, issued at an interest rate of 8.21 per cent. The third tranche of Cdn$29 million senior notes was issued with a five year average life repayable in years 2012 through 2016 and at an interest rate of 6.5 per cent.

In April 2009, ARC extended its uncommitted master shelf agreement from May 2009 to April 2012. The extended agreement allows for an aggregate draw of up to US$225 million (Cdn$283.5 million) in long term notes at a rate equal to the related U.S. treasuries corresponding to the term of the notes plus an appropriate credit risk adjustment at the time of issuance. As at March 31, 2009, the Trust has drawn US$87 million (Cdn$ 109.6 million) under this agreement. These amounts are reflected in the above table.

The Trust's long-term debt is secured in the form of a floating charge on all lands and assignments and a negative pledge on petroleum and natural gas properties.

7. ASSET RETIREMENT OBLIGATIONS

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

		March 31, 2009		December 31, 2008
Balance, beginning of period	**$**	**141.5**	$	140.0
Increase in liabilities relating to development activities		**0.4**		2.0
Increase in liabilities relating to change in estimate		**-**		2.6
Settlement of liabilities during the period		**(1.7)**		(12.4)
Accretion expense		**2.3**		9.3
Balance, end of period	**$**	**142.5**	$	141.5

The Trust's weighted average credit adjusted risk free rate as at March 31, 2009 was 6.6 per cent (6.6 per cent as at December 31, 2008).

8. CAPITAL MANAGEMENT

The Trust's objective when managing its capital is to maintain a conservative capital structure which will allow the Trust to:

- Fund its development and exploration program;
- Provide financial flexibility to execute on strategic opportunities;
- Maintain a level of distributions that, in normal times, in the opinion of Management and the Board of Directors, is sustainable for a minimum period of six months in order to normalize the effect of commodity price volatility to unitholders; and
- Maintain a level of distributions which will transfer tax liabilities to unitholders and minimize taxes paid by the Trust.

The Trust manages the following capital:

- Trust units and exchangeable shares;
- Long-term debt; and
- Working capital (defined as current assets less current liabilities excluding risk management contracts and future income taxes).

When evaluating the Trust's capital structure, management's objective is to limit net debt to less than 2.0 times annualized cash flow from operating activities and 20 per cent of total capitalization. As at March 31, 2009 the Trust's net debt to annualized cash flow from operating activities ratio is 1.6 and its net debt to total capitalization ratio is 19 per cent.

	March 31, 2009	December 31, 2008
Long-term debt	**703.8**	901.8
Accounts payable and accrued liabilities	**192.4**	194.4
Distributions payable	**28.1**	32.5
Cash and cash equivalents, accounts receivable and prepaid expenses	**(142.8)**	(166.8)
Net debt obligations (1)	**781.5**	961.9
Trust units outstanding and issuable for exchangeable shares (millions)	**236.0**	219.2
Trust unit price	**14.15**	20.10
Market capitalization (1)	**3,339.4**	4,405.9
Net debt obligations (1)	**781.5**	961.9
Total capitalization (1)	**4,120.9**	5,367.8
Net debt as a percentage of total capitalization	**19.0%**	17.9%
Net debt obligations to annualized cash flow from operating activities	**1.6**	1.0

(1) Market capitalization, net debt obligations and total capitalization 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.

The Trust manages its capital structure and makes adjustments to it in response to changes in economic conditions and the risk characteristics of the underlying assets. The Trust is able to change its capital structure by issuing new trust units, exchangeable shares, new debt or changing its distribution policy.

In addition to internal capital management the Trust is subject to various covenants under its credit facilities. Compliance with these covenants is monitored on a quarterly basis and as at March 31, 2009 the Trust is in compliance with all covenants. Refer to Note 6 for further details.

9. MARKET RISK MANAGEMENT

The Trust uses a variety of derivative instruments to reduce its exposure to fluctuations in commodity prices, foreign exchange rates, interest rates and power prices. 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 risk management contracts in place as at March 31, 2009 that do not qualify for hedge accounting:

Financial WTI Crude Oil Option Contracts In Conjunction with 2005 Redwater and North Pembina Cardium Unit Acquisition (1)

Term	Contract	Volume Bbl/d	Bought Put US$/bbl	Sold Put US$/bbl
Apr 09 – Dec 09	Put Spread	2,500	55.00	40.00

(1) Monthly average

Financial Cdn$ WTI Crude Oil Swap Contracts (2)

Term	Contract	Volume Bbl/d	Sold Swap Cdn$/bbl
Apr 09	Swap	4,000	62.65

(2) Monthly average

Financial AECO Natural Gas Option Contracts (3)

Term	Contract	Volume GJ/d	Bought Put Cdn$/GJ	Sold Put Cdn$/GJ	Sold Call Cdn$/GJ
Apr 09 – Dec 09	3 – Way Collar	20,000	6.50	4.50	8.00
Apr 09 – Oct 09	Collar	20,000	4.25	-	5.00

(3) AECO 7a monthly index

Energy Equivalent Swap Contracts (4) (5)

Term	Contract	Volume	Swap
Financial AECO Natural Gas Sales Contract			
Apr 09 – Dec 09	Swap	10,000 GJ/d	Cdn$ 4.67/GJ
Financial Cdn$ WTI Crude Oil Purchase Contract			
Apr 09 – Dec 09	Swap	650 bbl/d	Cdn$ 71.95/bbl

(4) AECO 5a monthly index
(5) Monthly average

Financial Basis Swap Contract (6)

Term	Contract	Volume mmbtu/d	Basis Swap US$/mmbtu
Apr 09 – Oct 10	Basis Swap-L3d	50,000	(1.0430)
Nov 10 – Oct 11	Basis Swap-Ld	20,000	(0.4850)
Nov 11 – Oct 12	Basis Swap-Ld	20,000	(0.4050)

(6) Receive Nymex Last Day (Ld) or Last 3 Day (L3d); pay AECO Monthly 7a

Financial Electricity Heat Rate Contracts (7)						
Term	Contract	Volume MWh	AESO Power $/MWh	AECO 5(a) $/GJ	multiplied by	Heat Rate GJ/MWh
Jan 10 – Dec 13	Heat Rate Swap	5.0	Receive AESO	Pay AECO		9.0

(7) Alberta Power Pool (monthly average 24x7), AECO Monthly (5a)

Financial Electricity Contracts (8)			
Term	Contract	Volume MWh	Bought Swap Cdn$/MWh
Apr 09 – Dec 12	Swap	5.0	72.50

(8) Alberta Power Pool (monthly average 24x7)

Following is a summary of all risk management contracts in place as at March 31, 2009 that qualify for hedge accounting:

Financial Electricity Contracts (9)			
Term	Contract	Volume MWh	Bought Swap Cdn$/MWh
Apr 09 – Dec 09	Swap	15.0	59.33
Jan 10 – Dec 10	Swap	5.0	63.00

(9) Alberta Power Pool (monthly average 24x7)

At March 31, 2009, the fair value of the contracts that were not designated as accounting hedges was a loss of $3.2 million. The Trust recorded a gain on risk management contracts of $9.7 million in the statement of income for the period ended March 31, 2009 ($48.2 million loss in 2008). This amount includes the realized and unrealized gains and losses on risk management contracts that do not qualify as effective accounting hedges.

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

		March 31, 2009		March 31, 2008
Fair value, beginning of period	**$**	**3.4**	$	(64.6)
Fair value, end of period (1)		**(3.2)**		(83.3)
Change in fair value of contracts in the period		**(6.6)**		(18.7)
Realized gain (loss) in the period		**16.3**		(29.5)
Gain (loss) on risk management contracts	**$**	**9.7**	$	(48.2)

(1) Intrinsic value of risk management contracts not designated as effective accounting hedges equals a loss of $5.9 million at March 31, 2009 ($57.5 million loss at March 31, 2008).

During 2007 the Trust entered into treasury rate lock contracts in order to manage the Trust's interest rate exposure on future debt issuances. During 2008 it was determined that the previously anticipated debt issuance was no longer expected to occur and the associated treasury rate lock contracts were unwound at a cost of $13.6 million. These contracts were originally designated as effective accounting hedges on their respective contract dates and hedge accounting was applied. During 2008, the $13.6 million loss was reclassified from Other Comprehensive Income ("OCI"), net of tax and recognized in net income.

The Trust's electricity contracts are intended to manage price risk on electricity consumption. Portions of the Trust's financial electricity contracts were designated as effective accounting hedges on their respective contract dates. A realized gain of $0.1 million for the three months ended March 31, 2009 (gain of $0.5 million in 2008) has been included in operating costs on these electricity contracts. The unrealized fair value gain of $0.3 million on these contracts has been recorded on the Consolidated Balance Sheet at March 31, 2009 with the movement in fair value recorded in OCI, net of tax. The fair value movement for the period ended March 31, 2009 is an unrealized loss of $3.0 million. As at March 31, 2009 $0.2 million of the unrealized fair value gain is attributed to contracts that will settle over the next twelve months.

The following table reconciles the movement in the fair value of the Trust's financial risk management contracts that have been designated as effective accounting hedges:

	March 31, 2009	March 31, 2008
Fair value, beginning of period	**$ 3.3**	$ (3.4)
Change in fair value of financial electricity contracts	**(3.0)**	1.8
Change in fair value of treasury rate lock contracts prior to de-designation	**-**	(6.2)
Reclassification of loss on treasury rate lock contracts to net income	**-**	13.6
Fair value, end of period (1)	**$ 0.3**	$ 5.8

(1) Intrinsic value of risk management contracts designated as effective accounting hedges equals a gain of $0.3 million at March 31, 2009 ($5.7 million gain at March 31, 2008).

All of the Trust's risk management contracts are transacted in liquid markets; fair values are determined using a valuation model based on published, third party, and market based price and rate information.

10. EXCHANGEABLE SHARES

(thousands)	March 31, 2009	December 31, 2008
Balance, beginning of period	**1,092**	1,310
Exchanged for trust units (1)	**(159)**	(218)
Balance, end of period	**933**	1,092
Exchange ratio, end of period	**2.57665**	2.51668
Trust units issuable upon conversion, end of period	**2,404**	2,748

(1) During the first three months of 2009, 159,116 ARL exchangeable shares were converted to trust units at an average exchange ratio of 2.55441, compared to 218,455 exchangeable shares at an average exchange ratio of 2.36901 during the year ended 2008.

Following is a summary of the non-controlling interest for 2009 and 2008:

	March 31, 2009	December 31, 2008
Non-controlling interest, beginning of period	**$ 42.4**	$ 43.1
Reduction of book value for conversion to trust units	**(6.2)**	(7.6)
Current period net income attributable to non-controlling interest	**0.2**	6.9
Non-controlling interest, end of period	**36.4**	42.4
Accumulated earnings attributable to non-controlling interest	**$ 41.2**	$ 41.0

11. UNITHOLDERS' CAPITAL

	March 31, 2009		December 31, 2008	
(thousands)	Number of trust units	$	Number of trust units	$
Balance, beginning of period	**216,435**	**2,600.7**	210,232	2,465.7
Issued for cash	**15,474**	**253.0**	-	-
Issued on conversion of ARL exchangeable shares (Note 10)	**406**	**6.2**	517	7.6
Issued on exercise of employee rights	**-**	**-**	238	4.2
Distribution reinvestment program	**1,269**	**18.7**	5,448	123.2
Trust unit issue costs, net of tax (1)	**-**	**(11.0)**	-	-
Balance, end of period	**233,584**	**2,867.6**	216,435	2,600.7

(1) Amount is net of tax of $1.9 million for the period ended March 31, 2009.

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

(thousands)	March 31, 2009	March 31, 2008
Weighted average trust units [1]	**226,477**	211,028
Trust units issuable on conversion of exchangeable shares [2]	**2,404**	2,746
Dilutive impact of rights [3]	**-**	172
Diluted trust units and exchangeable shares	**228,881**	213,946

(1) Weighted average trust units exclude trust units issuable for exchangeable shares.
(2) Diluted trust units include trust units issuable for outstanding exchangeable shares at the year-end exchange ratio.
(3) There are no rights outstanding as of March 31, 2009 and therefore, no dilutive impact. Previously outstanding rights were dilutive and therefore were included in the diluted unit calculation for 2008.

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

12. DEFICIT AND ACCUMULATED OTHER COMPREHENSIVE (LOSS) INCOME

		March 31, 2009		December 31, 2008
Accumulated earnings	**$**	**2,746.4**	$	2,724.1
Accumulated distributions		**(3,309.0)**		(3,227.0)
Deficit	**$**	**(562.6)**	$	(502.9)
Accumulated other comprehensive (loss) income		**(0.4)**		1.9
Deficit and accumulated other comprehensive (loss) income	**$**	**(563.0)**	$	(501.0)

The accumulated other comprehensive (loss) income balance is composed of the following items:

		March 31, 2009		December 31, 2008
Unrealized gains and losses on financial instruments designated as cash flow hedges	**$**	**(0.1)**	$	2.0
Net unrealized gains and losses on available-for-sale reclamation funds' investments		**(0.3)**		(0.1)
Accumulated other comprehensive (loss) income, end of period	**$**	**(0.4)**	$	1.9

13. RECONCILIATION OF CASH FLOW FROM OPERATING ACTIVITIES AND DISTRIBUTIONS

Distributions are calculated in accordance with the Trust Indenture. To arrive at distributions, cash flow from operating activities is reduced by reclamation fund contributions including interest earned on the funds, a portion of capital expenditures and, when applicable, debt repayments. The portion of cash flow from operating activities withheld to fund capital expenditures and to make debt repayments is at the discretion of the Board of Directors.

		March 31, 2009		March 31, 2008
Cash flow from operating activities	**$**	**124.3**	$	209.9
Deduct:				
Cash withheld to fund current period capital expenditures		**(43.8)**		(79.8)
Net reclamation fund withdrawals (contributions)		**1.5**		(3.3)
Distributions [1]		**82.0**		126.8
Accumulated distributions, beginning of period		**3,227.0**		2,657.0
Accumulated distributions, end of period	**$**	**3,309.0**	$	2,783.8
Distributions per unit [2]	**$**	**0.36**	$	0.60
Accumulated distributions per unit, beginning of period	**$**	**23.70**	$	21.03
Accumulated distributions per unit, end of period [3]	**$**	**24.06**	$	21.63

(1) Distributions include accrued and non-cash amounts of $13.8 million for the period ended March 31, 2009 ($26 million for the period ended March 31, 2008).
(2) Distributions per trust unit reflect the sum of the per trust unit amounts declared monthly to unitholders.

(3) Accumulated distributions per unit reflect the sum of the per trust unit amounts declared monthly to unitholders since the inception of the Trust in July 1996.

14. WHOLE TRUST UNIT INCENTIVE PLAN

Compensation expense associated with the Whole Trust Unit Incentive Plan (“the Whole Unit Plan”) is granted in the form of Restricted Trust Units (“RTUs”) and Performance Trust Units (“PTUs”) and is determined based on the intrinsic value of the Whole Trust Units at each period end.

The Trust recorded non-cash compensation (recovery) expense of $(10.8) million and $(1.3) million to general and administrative and operating expenses, respectively, and capitalized $(2.2) million to property, plant and equipment in the three months ended March 31, 2009 for the estimated change in the Plan liability ($11.9 million, $1.9 million, and $2.0 million as expense for the three months ended March 31, 2008). The non-cash compensation recovery was based on the March 31, 2009 unit price of $14.15 ($26.38 at March 31, 2008), accrued distributions, a performance multiplier, and the estimated number of units to be issued on maturity.

The following table summarizes the RTU and PTU movement for the three months ended March 31, 2009:

	Number of RTUs (thousands)	**Number of PTUs (thousands)**
Balance, beginning of period	756	959
Granted	377	244
Vested	(180)	(154)
Forfeited	(15)	(10)
Balance, end of period	938	1,039

The change in the net accrued long-term incentive compensation liability relating to the Whole Trust Unit Incentive Plan can be reconciled as follows:

		March 31, 2009		December 31, 2008
Balance, beginning of period	**$**	**31.9**	$	30.3
Change in net liabilities in the period				
General and administrative expense		**(10.8)**		1.1
Operating expense		**(1.3)**		(0.1)
Property, plant and equipment		**(2.2)**		0.6
Balance, end of period [(1)]	**$**	**17.6**	$	31.9
Current portion of liability		**10.9**		18.8
Accrued long-term incentive compensation	**$**	**7.0**	$	14.2

(1) Includes $0.3 million of recoverable amounts recorded in accounts receivable as at March 31, 2009 ($1.1 million for 2008).

During the first three months of 2009 cash payments of $7.8 million were made to employees relating to the Whole Unit Plan compared to $18.5 million paid in April of 2008. In October 2008, vesting periods were revised from April and October to March and September of each year commencing in 2009.

15. COMMITMENTS AND CONTINGENCIES

Following is a summary of the Trust’s contractual obligations and commitments as at March 31, 2009:

	Payments due by period				
	2009	2010-2011	2012-2013	Thereafter	Total
Debt repayments [(1)]	22.8	492.0	81.4	107.6	703.8
Interest payments [(2)]	11.8	22.9	15.9	10.2	60.8
Reclamation fund contributions [(3)]	5.3	9.5	8.3	67.9	91.0
Purchase commitments	8.0	13.0	7.1	5.1	33.2
Transportation commitments [(4)]	-	14.9	21.9	21.0	57.8
Operating leases	5.7	9.8	14.3	81.8	111.6
Risk management contract premiums [(5)]	14.1	-	-	-	14.1
Total contractual obligations	67.7	562.1	148.9	293.6	1,072.3

(1) Long-term and short-term debt, excluding interest.
(2) Fixed interest payments on senior secured notes.
(3) Contribution commitments to a restricted reclamation fund associated with the Redwater property.
(4) Fixed payments for transporting production from the Dawson gas plant, expected to be operational in early 2010.
(5) Fixed premiums to be paid in future periods on certain commodity risk management contracts.

In addition to the above Risk management contract premiums, the Trust has commitments related to its risk management program (see Note 9).

The Trust enters into commitments for capital expenditures in advance of the expenditures being made. At a given point in time, it is estimated that the Trust has committed to capital expenditures equal to approximately one quarter of its capital budget by means of giving the necessary authorizations to incur the expenditures in a future period. The Trust's 2009 capital budget has been set at $350 million. This commitment has not been disclosed in the commitment table as it is of a routine nature and is part of normal course of operations for active oil and gas companies and trusts.

The 2009 capital budget of $350 million includes approximately $11 million for leasehold development costs related to the Trust's new office space in downtown Calgary. These costs will be incurred throughout 2009 with additional amounts to be incurred in 2010. The operating lease commitments for the new space are included in the table above.

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