NEWS RELEASE
May 5, 2010

ARC ENERGY TRUST ANNOUNCES FIRST QUARTER 2010 RESULTS

Calgary, May 5, 2010 (AET.UN and ARX – TSX) ARC Energy Trust ("ARC" or "the Trust") announces the results for the first quarter ended March 31, 2010.

	Three Months Ended March 31	
	2010	2009
FINANCIAL		
(Cdn$ millions, except per unit and per boe amounts)		
Revenue before royalties	**314.1**	225.2
Per unit (1)	**1.25**	0.98
Per boe	**51.93**	38.57
Cash flow from operating activities (2)	**158.7**	124.3
Per unit (1)	**0.63**	0.54
Per boe	**26.24**	21.29
Net income	**139.4**	22.3
Per unit (3)	**0.56**	0.10
Distributions	**75.0**	82.0
Per unit (1)	**0.30**	0.36
Per cent of cash flow from operating activities (2)	**47**	66
Net debt outstanding (4)	**677.8**	781.5
OPERATING		
Production		
Crude oil (bbl/d)	**27,640**	28,806
Natural gas (mmcf/d)	**217.9**	193.8
Natural gas liquids (bbl/d)	**3,252**	3,764
Total (boe/d)	**67,207**	64,872
Average prices		
Crude oil ($/bbl)	**76.26**	46.44
Natural gas ($/mcf)	**5.42**	5.20
Natural gas liquids ($/bbl)	**60.33**	38.86
Oil equivalent ($/boe)	**51.85**	38.40
Operating netback ($/boe)		
Commodity and other revenue (before hedging)	**51.93**	38.57
Transportation costs	**(0.99)**	(0.95)
Royalties	**(8.58)**	(6.34)
Operating costs	**(9.29)**	(10.12)
Netback (before hedging)	**33.07**	21.16
TRUST UNITS		
(millions)		
Units outstanding, end of period (5)	**252.8**	236.0
Weighted average trust units (6)	**251.8**	228.9
TRUST UNIT TRADING STATISTICS		
(Cdn$, except volumes) based on intra-day trading		
High	**22.49**	20.90
Low	**19.80**	11.73
Close	**20.50**	14.15
Average daily volume (thousands)	**1,287**	1,240

(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 2010 would be $162 million ($0.64 per unit). Distributions as a percentage of Cash Flow would be 46 per cent for the first quarter of 2010.

(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) For the first quarter of 2010, includes 0.9 million (0.9 million in 2009) exchangeable shares exchangeable into 2.759 trust units (2.577 in 2009) each for an aggregate 2.4 million (2.4 million in 2009) trust units.

(6) Includes trust units issuable for outstanding exchangeable shares at period end.

ACCOMPLISHMENTS / FINANCIAL UPDATE

- Production volumes for the quarter averaged 67,207 boe per day, an increase of four per cent compared to the first quarter of 2009. The majority of the increase in production was a result of an acquisition that closed late in 2009 with the remainder attributed to increased production in the greater Dawson area. ARC continues to expect full year average production between 70,500 and 72,500 boe per day with the planned startup of an ARC operated gas plant at Dawson in the second quarter.

- Cash flow from operating activities was $158.7 million, ($0.63 per unit), a 28 per cent increase from the $124.3 million ($0.54 per unit) achieved in the comparable quarter in 2009. This increase was primarily attributed to a continued recovery of crude oil prices. Crude oil prices strengthened during the first quarter of 2010 to $76.26 per barrel from $46.44 per barrel in the first quarter of 2009 as the economy showed signs of recovery. Natural gas prices were soft throughout the first quarter, averaging $5.42 per mcf as a result of continued concern over surplus natural gas supplies in North America.

- Operating costs decreased to $9.29 per boe in the quarter of 2010 as compared to $10.12 per boe in the first quarter of 2009. Total operating costs decreased $2.9 million, or five per cent in the first quarter of 2010, despite production increasing four per cent. The decrease in costs is primarily attributed to lower power costs as well as cost savings and efficiencies achieved by the operations team.

- ARC commenced its record $610 million 2010 capital program with $128.3 million of capital expenditures in the first quarter. During the quarter, ARC drilled 23 oil wells and 26 natural gas wells with a 100 per cent success rate. Of the 23 oil wells drilled, six horizontal wells were drilled in the Goodlands field into the Amaranth zone and five horizontal and two vertical wells were drilled in the Pembina area into the Cardium zone. After payment of distributions, ARC was able to fund 80 per cent of its first quarter capital program with cash flow from operating activities and proceeds from the distribution re-investment program ("DRIP") with the remaining portion being funded through debt.

- At March 31, 2010, ARC had a net debt balance of $677.8 million down $224.6 million from a year-end balance of $902.4 million, following the receipt of approximately $240 million from an equity offering completed on January 5, 2010. During the first quarter, ARC issued US$50 million of long-term notes under its Master Shelf Agreement at a coupon rate of 4.98 per cent. With $646.3 million of unused credit available and a net debt to annualized year-to-date cash flow from operating activities of 1.1 times, ARC is well positioned to finance the remainder of its 2010 capital program from cash flow and available credit.

- ARC plans to convert to a dividend paying corporation effective January 1, 2011. The Board of Directors has approved the overall strategy and the detailed implementation steps are currently being defined. The conversion plans will be mailed to unitholders prior to a unitholder meeting planned for December 15, 2010. Current plans would see a dividend policy similar to the existing distribution policy with dividends being paid monthly.

- **Montney Resource Play Development**
  Production from the greater Dawson area reached a record 75 mmcf per day in the first quarter with 65.6 mmcf per day produced from ARC's Dawson field and 9.4 mmcf per day coming from a partner operated field at Sunrise.

  During the first quarter of 2010, ARC spent $41.4 million on development activities in the Dawson area including drilling 14 horizontal wells and three vertical wells. Four horizontal wells were completed during the quarter. ARC incurred $3.9 million of capital expenditures on the construction of its Dawson Phase 1 gas plant during the first quarter. From inception to March 31, 2010, ARC has spent $61.5 million on the gas plant. Subsequent to quarter end, construction and commissioning of the gas plant was completed with start-up procedures now underway. Sales gas is anticipated to be flowing through the plant by the middle of May. ARC currently has enough wells awaiting tie-in to the gas plant to fill it to its 60 mmcf per day capacity within two weeks of plant start-up.

  During April 2010, ARC submitted an application for the Phase 2 portion of the Dawson gas plant to the British Columbia Oil and Gas Commission ("OGC"). Phase 2 consists of the construction of a second 60 mmcf per day train at the Dawson gas plant and, if approved, is anticipated to increase the plant processing capacity from 60 mmcf per day to 120 mmcf per day. Phase 2 is expected to be completed in the first quarter of 2011.

- **Cardium Resource Play Development**
  ARC operates approximately 25 per cent of the Pembina Cardium oil field with an average 65 per cent working interest in 166 gross sections (126 net). During the first quarter, ARC spent $14.9 million in the Pembina area, principally on the drilling of five horizontal wells and two vertical wells. Two of the horizontal wells and both of the vertical wells were in the early stages of completion at quarter end, with early indications suggesting that these will be average horizontal wells for the area. ARC also drilled one horizontal Cardium well and completed two horizontal wells drilled in the fourth quarter of 2009 in the Garrington area. Thirty day initial production rates for the completed wells averaged just over 100 boe per day. ARC expects to spend at least another $40 million during the remainder of the year as we further our understanding of the potential for the recovery of significant incremental oil volumes through the application of horizontal drilling and completion technology.

- **Enhanced Oil Recovery Initiatives**
  During the first quarter of 2010, ARC spent $4.1 million on enhanced oil recovery ("EOR") initiatives. Work on the Redwater CO_2 pilot project continues and both the CO_2 injection and oil production facilities are operating. Results to date are encouraging but ARC anticipates that it will take until later in 2010 to determine to what extent the pilot has been successful in mobilizing incremental volumes of oil. While the pilot project may indicate enhanced recovery, the outlook for crude oil prices and the cost and availability of CO_2 will be determining factors in ARC's ability to achieve commercial viability for a full scale EOR scheme at Redwater.

MANAGEMENT APPOINTMENTS

- Terry Anderson has been appointed Vice-President, Engineering. Terry will be responsible for providing executive leadership to the Engineering team on our operated properties and our Joint Venture team on non-operated properties. Additionally, Terry will be stewarding our Capital program and ensuring with the support of other groups, that we continue to develop our significant oil and gas reserves at low costs. Terry started with ARC in 2000 as an Operations Engineer, progressed to Manager of Operations and was promoted to VP Operations in 2005. During his time with ARC, Terry has worked on almost all of our assets.

- Al Roberts has been promoted to Vice-President, Operations. Al has over 30 years of experience within the oil and gas industry – 13 of those years have been here at ARC. Al joined ARC in 1997 and was our first field based supervisor and has been instrumental in building ARC's operations team. Most recently, Al was Manager of Southern Operations.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This management's discussion and analysis ("MD&A") is ARC management's analysis of its financial performance and significant trends or external factors that may affect future performance. It is dated May 4, 2010 and should be read in conjunction with the unaudited Consolidated Financial Statements for the period ended March 31, 2010 and the audited Consolidated Financial Statements and MD&A as at and for the year ended December 31, 2009 as well as ARC'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 ARC's disclosure under "Non-GAAP Measures" and "Forward-Looking Statements" included at the end of this MD&A.

ARC Energy Trust ("ARC") or ("the Trust") is a mid-sized energy company and one of Canada's largest producers of conventional oil and gas production. Currently structured as a trust, ARC develops and acquires oil and gas properties in western Canada. ARC plans to convert to a dividend paying corporation on January 1, 2011.

ARC's goal is **value creation** by providing superior long-term returns to unitholders achieved through the development of large oil and natural gas pools. Our key activities that support this objective are:

1. **Resource Plays** - Acquisition and development of land and producing properties with large volumes of oil and gas in place.
   ARC's most significant resource plays include the Montney development at Dawson, northeastern British Columbia, Ante Creek in northern Alberta and the Cardium formation at Pembina in central Alberta.

2. **Conventional Oil & Gas Production** - Maximizing production while controlling operating costs on oil and gas wells located within ARC's seven core producing areas in western Canada. As well, 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. Current oil production is predominantly light and medium quality.
   ARC's total production in 2009 was balanced with 51 per cent of production from natural gas and 49 per cent production from oil and natural gas liquids. ARC continues to develop its core areas to increase recoverable reserves through development drilling, optimization and waterflood programs.

3. **Enhanced Oil Recovery ("EOR")** - Evaluation and implementation of enhanced oil recovery programs to increase ARC's recoverable reserves in existing oil pools.
   ARC has non-operated interests in the Weyburn and Midale units in Saskatchewan, where operators have implemented CO_2 injection programs to increase recoverable oil reserves. In 2008, ARC initiated a CO_2 pilot program at Redwater in Alberta.

ARC provides returns to unitholders through monthly cash distributions and the potential for capital appreciation. ARC currently distributes $0.10 per unit per month to its unitholders. Since ARC's inception in July 1996, ARC has distributed $3.6 billion or $25.28 per unit. The remaining cash flow is used to fund reclamation costs and a portion of capital expenditures. During the first quarter of 2010, cash flow and proceeds from the DRIP program funded $102.1 million of capital expenditures and a net withdrawal of $3 million to the reclamation funds.

ARC's unitholders can also benefit from potential capital appreciation associated with increased market values for ARC's production and reserves. ARC's management strives to replace and grow both production and reserves through drilling new wells and associated oil and natural gas development activities. To support this, the majority of ARC's annual capital budget is deployed on a balanced drilling program of low and moderate risk wells, well tie-ins and other related costs and the acquisition of undeveloped land.

Tables 1 and 2 below outline ARC's success in executing its business strategy in pursuit of value creation. Table 1 details ARC's normalized production, reserves and distributions per unit over the past three periods:

Table 1

Per Trust Unit	First quarter 2010	Full year 2009	Full year 2008
Normalized production, boe per unit [(1)] [(2)]	**0.28**	0.27	0.29
Normalized reserves, boe per unit [(1)] [(3)]	**N/A**	1.57	1.42
Distributions per unit	**$0.30**	$1.28	$2.67

(1) Normalized indicates that all periods 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 per unit values.
(2) Production per unit represents daily average production (boe) per thousand trust units and is 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), as determined by ARC's independent reserve evaluator solely at year-end, divided by period end trust units outstanding including trust units issuable for exchangeable shares.

ARC's business plan has resulted in significant operational success and contributed to a trailing five year annualized return per unit of 12.5 per cent (Table 2).

Table 2

Total Returns [(1)] ($ per unit except for per cent)	**Trailing One Year**	Trailing Three Year	Trailing Five Year
Distributions per unit	**1.22**	6.05	10.59
Capital appreciation per unit	**6.35**	(0.75)	2.35
Annualized total return per unit	**54.6%**	8.5%	12.5%
Total return per unit	**54.6%**	27.8%	80.3%
S&P/TSX Exploration & Producers Index	**46.3%**	5.8%	53.4%

(1) Calculated as at March 31, 2010.

2010 Guidance and Financial Highlights

Table 3 is a summary of ARC's 2010 Guidance and a review of 2010 actual results for the first quarter compared to guidance:

Table 3

	2010 Guidance	2010 Actual YTD	% Change
Production (boe/d)	**70,500 – 72,500**	67,207	-
Expenses ($/boe):			
Operating costs	**10.30**	9.29	(10)
Transportation	**1.00**	0.99	(1)
G&A expenses (cash & non-cash)	**2.85**	3.50	23
Interest	**1.40**	1.82	30
Capital expenditures ($ millions)	**610**	128.3	-
Annual weighted average trust units and trust units issuable (millions)	**254**	252	-

The first quarter results were in line with guidance with the exception of general and administrative ("G&A") expenses and interest. G&A exceeded guidance due to higher staff compensation costs. The largest item included a special performance bonus approved by the Board of Directors due to exceptional 2009 results. Interest exceeded guidance as a result of a one-time make whole premium payment on the early retirement of some senior secured notes. Revisions to the guidance have not been made at this time as these items are expected to normalize during the course of 2010. The 2010 Guidance provides unitholders with information on management's expectations for results of operations, excluding any acquisitions or dispositions for 2010. Readers are cautioned that the 2010 Guidance may not be appropriate for other purposes.

2010 First Quarter Financial and Operational Results

Financial Highlights

Table 4

	Three Months Ended March 31		
(Cdn$ millions, except per unit and volume data)	**2010**	2009	% Change
Cash flow from operating activities	**158.7**	124.3	28
Cash flow from operating activities per unit (1)	**0.63**	0.54	17
Net income	**139.4**	22.3	525
Net income per unit (2)	**0.56**	0.10	460
Distributions per unit (3)	**0.30**	0.36	(17)
Distributions as a per cent of cash flow from operating activities	**47**	66	(29)
Average daily production (boe/d) (4)	**67,207**	64,872	4

(1) Per unit amounts are based on weighted average trust units outstanding plus trust units issuable for exchangeable shares at period 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.

Cash Flow from Operating Activities

Cash flow from operating activities increased by 28 per cent in the first quarter of 2010 to $158.7 million from $124.3 million in the first quarter of 2009. Increases in crown royalties and a decrease in cash gain on risk management contracts were more than offset by the 35 per cent ($13.45 per boe) increase in commodity prices and a four per cent increase in production relative to the first quarter of 2009. Details of the change in cash flow from operating activities in the first quarter of 2009 to the first quarter of 2010 are presented in Table 5.

Table 5

	($ millions)	($ per trust unit)	(% Change)
Q1 2009 Cash flow from Operating Activities	**124.3**	**0.54**	**-**
Volume variance	8.1	0.04	7
Price variance	80.7	0.35	65
Cash gains on risk management contracts	(15.0)	(0.07)	(12)
Royalties	(14.9)	(0.07)	(12)
Expenses:			
Transportation	(0.4)	-	-
Operating (1)	3.4	0.01	3
Cash G&A	(10.8)	(0.05)	(9)
Interest	(5.2)	(0.02)	(4)
Realized foreign exchange loss	(0.5)	-	-
Weighted average trust units	-	(0.05)	-
Non-cash and other items (2)	(11.0)	(0.05)	(9)
Q1 2010 Cash flow from Operating Activities	**158.7**	**0.63**	**-**

(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.

2010 Cash Flow from Operating Activities Sensitivity

Table 6 illustrates sensitivities to pre-hedged operating income items with operational changes and changes to the business environment and the resulting impact on cash flows from operating activities in total and per trust unit:

Table 6

			Impact on Annual Cash Flow from Operating Activities [4]			
Business Environment [1]		Assumption		Change		$/Unit
Oil price (US$WTI/bbl) [2][3]	$	85.00	$	1.00	$	0.04
Natural gas price (Cdn$AECO/mcf) [2][3]	$	4.25	$	0.10	$	0.03
Cdn$/US$ exchange rate [2][3][5]		1.05	$	0.01	$	0.03
Interest rate on debt [2]	%	4.00	%	1.0	$	0.01
Operational						
Liquids production volume (bbl/d)		31,500	%	1.0	$	0.03
Gas production volumes (mmcf/d)		240.0	%	1.0	$	0.01
Operating expenses per boe	$	10.30	%	1.0	$	0.01
Cash G&A and Whole Unit Plan expenses per boe	$	2.85	%	10.0	$	0.03

(1) Calculations are performed independently and may not be indicative of actual results that would occur when multiple variables change at the same time.
(2) Prices and rates are indicative of published forward prices and rates at the time of this MD&A. The calculated impact on annual cash flow from operating activities would only be applicable within a limited range of these amounts.
(3) Analysis does not include the effect of hedging contracts.
(4) Assumes constant working capital.
(5) Includes impact of foreign exchange on crude oil prices that are presented in U.S. dollars. This amount does not include a foreign exchange impact relating to natural gas prices as they are presented in Canadian dollars in this sensitivity.

Net Income

Net income in the first quarter of 2010 was $139.4 million ($0.56 per unit), a $117.1 million increase as compared to $22.3 million ($0.10 per unit) in the first quarter of 2009. The increase reflects the recovery in oil prices from a year ago resulting in higher revenues. In addition, net income for the first quarter of 2010 has been increased by certain non-cash items during the period including:

- An $83.7 million unrealized non-cash gain on risk management contracts ($62.7 million net of future income taxes) as compared to a $6.6 million ($4.9 million net of future income taxes) unrealized non-cash loss for the first quarter of 2009.

- A $10.8 million gain on foreign exchange ($8.1 million net of future income taxes) as compared to a $14.6 million ($10.9 million net of future income taxes) loss on foreign exchange for the first quarter of 2009.

Production

Production volumes averaged 67,207 boe per day in the first quarter of 2010 compared to 64,872 boe per day in the same period of 2009 as detailed in Table 7. The increase in first quarter of 2010 production is a result of an acquisition that closed in late 2009 and from new wells coming on production.

Table 7

	Three Months Ended March 31		
Production	**2010**	2009	% Change
Light & medium crude oil (bbl/d)	**26,676**	27,720	(4)
Heavy oil (bbl/d)	**964**	1,086	(11)
Natural gas (mmcf/d)	**217.9**	193.8	12
Natural gas liquids (“NGL”) (bbl/d)	**3,252**	3,764	(14)
Total production (boe/d) [1]	**67,207**	64,872	4
% Natural gas production	**54**	50	8
% Crude oil and liquids production	**46**	50	(8)

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

Light and medium crude oil production decreased to 26,676 barrels per day compared to 27,720 barrels per day in 2009, while heavy oil production declined by 122 barrels per day. This slight decrease is mainly attributable to minor property dispositions made in 2009. However, when compared to the fourth quarter of 2009, ARC's total crude oil production increased slightly. This increase was a result of the acquisition of additional properties in Ante Creek in late 2009 and a successful drilling program at Goodlands, which helped offset natural decline. Natural gas production was 217.9 mmcf per day in the first quarter of 2010, an increase of 12 per cent from the 193.8 mmcf per day produced in the first quarter of 2009. The increase is mainly attributable to the late 2009 acquisition of Ante Creek properties as well as new production from wells in the Montney West area. In addition, ARC has been able to take advantage of some additional processing capacity in the Dawson region, resulting in increased production of 12 mmcf per day compared to the fourth quarter of 2009.

ARC's objective is to maintain annual production, to the fullest extent possible, through the drilling of wells and other development activities while giving considerations to capital spending constraints and the economics of developing ARC's resources. In fulfilling this objective, there may be fluctuations in production resulting from the timing of new wells coming on-stream. During the first quarter of 2010, ARC drilled 49 gross wells (44 net wells) on operated properties; 23 gross oil wells, and 26 gross natural gas wells with a 100 per cent success rate.

ARC expects that 2010 full year production will average approximately 70,500 to 72,500 boe per day and that it will drill a total of 211 gross wells (195 net) on operated properties and participate in an additional 91 gross wells (18 net) to be drilled on non-operated properties. ARC estimates that total 2010 production will increase from a range of 11 to 14 per cent over 2009 production levels as a result of its 2010 drilling program and the start-up of its new gas plant in the Dawson area.

Table 8 summarizes ARC's production by core area:

Table 8

	Three Months Ended March 31, 2010				Three Months Ended March 31, 2009			
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	**6,592**	**1,230**	**26.1**	**1,008**	7,127	1,390	27.7	1,116
N.E. BC & N.W. AB	**16,870**	**691**	**93.1**	**673**	13,619	754	73.4	629
Northern AB	**11,001**	**4,707**	**32.4**	**898**	9,493	4,353	25.4	907
Pembina & Redwater	**13,132**	**9,288**	**19.5**	**586**	13,798	9,648	19.1	972
S.E. AB & S.W. Sask.	**8,615**	**1,046**	**45.3**	**13**	8,789	994	46.7	15
S.E. Sask. & MB	**10,997**	**10,678**	**1.5**	**74**	12,046	11,667	1.5	125
Total	**67,207**	**27,640**	**217.9**	**3,252**	64,872	28,806	193.8	3,764

(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 increased to $314.1 million in the first quarter of 2010, $88.9 million higher than 2009 revenue of $225.2 million. The increase in realized oil prices accounted for $77.3 million of the $69.3 million increase, offset by $8 million attributable to lower oil volumes. Natural gas revenue increased by $15.7 million in the first quarter of 2010 relative to the same period in 2009, with the increase attributable to higher natural gas volumes.

A breakdown of revenue is outlined in Table 9:

Table 9

Revenue ($ millions)	Three Months Ended March 31 **2010**	2009	% Change
Oil revenue	**189.7**	120.4	58
Natural gas revenue	**106.3**	90.6	17
NGL revenue	**17.6**	13.2	33
Total commodity revenue	**313.6**	224.2	40
Other revenue	**0.5**	1.0	(50)
Total revenue	**314.1**	225.2	39

Commodity Prices Prior to Hedging

Table 10

	Three Months Ended March 31		
	2010	2009	% Change
Average Benchmark Prices			
AECO gas ($/mcf) (1)	**5.35**	5.64	(5)
WTI oil (US$/bbl) (2)	**78.79**	43.21	82
Cdn$ / US$ exchange rate	**1.04**	1.25	(17)
WTI oil (Cdn$/bbl)	**81.94**	53.85	52
ARC Realized Prices Prior to Hedging			
Oil ($/bbl)	**76.26**	46.44	64
Natural gas ($/mcf)	**5.42**	5.20	4
NGL ($/bbl)	**60.33**	38.86	55
Total commodity revenue before hedging ($/boe)	**51.85**	38.40	35
Other revenue ($/boe)	**0.08**	0.17	(53)
Total revenue before hedging ($/boe)	**51.93**	38.57	35

(1) Represents the AECO monthly posting.
(2) WTI represents posting price of West Texas Intermediate oil.

Oil prices continued to recover in the first quarter of 2010 with WTI prices averaging US$78.79 per barrel as compared to US$43.21 per barrel for the first quarter of 2009. Actual realized oil prices lagged behind US$WTI as a result of the strengthening of the Canadian dollar compared to the U.S. dollar mitigated by a narrowing of price differentials. ARC's oil production consists predominantly of light and medium crude oil while heavy oil accounts for less than five per cent of ARC's crude oil production. The realized price for ARC's oil, before hedging, was $76.26 per barrel, a 64 per cent increase over the first quarter 2009 realized price of $46.44 per barrel.

Natural gas prices declined by five percent for the first quarter of 2010 in comparison to 2009. Alberta AECO Hub natural gas prices, which are commonly used as an industry reference, averaged $5.35 per mcf in the first quarter of 2010 compared to $5.64 per mcf in the same period of 2009. ARC's realized gas price, before hedging, increased slightly by four per cent to $5.42 per mcf compared to $5.20 per mcf in the first quarter of 2009. ARC's realized gas price is based on its natural gas sales portfolio consisting of sales priced at the AECO monthly index, the AECO daily spot market, eastern and mid-west United States markets and a portion to aggregators. The outlook on natural gas prices remains weak, with North American storage levels being unusually high for this time of year. As a result, the forward curve for natural gas prices has weakened from the fourth quarter of 2009 and prices are expected to range from $3.50 to $4.50 per mcf for the remaining three quarters of 2010.

Prior to hedging activities, ARC's total realized commodity price was $51.93 per boe in the first quarter of 2010, a 35 per cent increase from the $38.57 per boe received prior to hedging in the first quarter of 2009.

Risk Management and Hedging Activities

ARC maintains a risk management program to reduce the volatility of revenues and increase the certainty of cash flows, and to protect acquisition and development economics.

Gains or losses on risk management contracts comprise realized and unrealized gains or losses that do not meet the accounting definition requirements of an effective hedge, even though ARC 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 Consolidated Statements of Income and Deficit.

During the first quarter of 2010, ARC realized $1.3 million of cash gains on its risk management contracts. The largest contributor to the cash gains was $3.9 million recorded on ARC's natural gas swaps, offset by cash losses of $3.7 million on ARC's natural gas basis swap contracts.

In the first quarter of 2010, ARC recorded an $83.7 million unrealized mark-to-market gain on its risk management contracts having a net fair value of $78.9 million at March 31, 2010. The net gain position is primarily attributed to ARC's natural gas contracts reflecting the outlook of softer natural gas prices relative to year-end. The fair value of risk management contracts represent the expected market price to buy-out ARC's contracts as of March 31, 2010 and may differ from what will eventually be realized.

In the first quarter of 2009, ARC recorded an unrealized loss on risk management contracts of $6.6 million, primarily attributed to losses on ARC's power and interest rate contracts.

Table 11 summarizes the total gain (loss) on risk management contracts for the first quarter of 2010 as compared to the same period in 2009:

Table 11

Risk Management Contracts ($ millions)	Crude Oil & Liquids	Natural Gas	Foreign Currency	Power [3]	**Q1 2010 Total**	Q1 2009 Total
Realized cash gain (loss) on contracts [1]	0.2	0.2	1.3	(0.4)	**1.3**	16.3
Unrealized (loss) gain on contracts [2]	(2.5)	84.2	(0.6)	2.6	**83.7**	(6.6)
Total (loss) gain on risk management contracts	(2.3)	84.4	0.7	2.2	**85.0**	9.7

(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 11 exclude a $0.2 million realized loss and a nominal unrealized loss for ARC's power contracts that have been designated as effective hedges for accounting purposes (2009 – gain of $0.1 million and loss of $3 million, respectively). 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.

ARC currently limits the amount of forecast production that can be hedged to a maximum 50 per cent. The following table is a summary of ARC's positions for crude oil and natural gas as at March 31, 2010.

Table 12

Hedge Positions As at March 31, 2010 [1][2]	**Q2 2010**		**Q3 2010**		**Q4 2010**		**2011**	
Crude Oil	US$/bbl	bbl/day	US$/bbl	bbl/day	US$/bbl	bbl/day	US$/bbl	bbl/day
Sold Call	92.00	15,000	92.00	15,000	92.00	15,000	100.00	4,000
Bought Put	**76.67**	**15,000**	**76.67**	**15,000**	**76.67**	**15,000**	**80.00**	**4,000**
Sold Put	60.00	4,000	60.00	4,000	60.00	4,000	60.00	4,000
Natural Gas	Cdn$/GJ	GJ/day	Cdn$/GJ	GJ/day	Cdn$/GJ	GJ/day	Cdn$/GJ	GJ/day
Sold Call	5.55	101,101	5.55	101,101	5.59	87,110	6.06	45,000[3]
Bought Put	**5.55**	**101,101**	**5.55**	**101,101**	**5.59**	**87,110**	**6.06**	**45,000[3]**
Sold Put	-	-	-	-	-	-	-	-

(1) The prices and volumes noted above represent 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 based on offsetting basis positions and the quarter end exchange rate.
(2) In addition to positions shown here ARC has entered into additional basis positions for 30,000 mmbtu per day from April 2010 to October 2010 and 15,000 mmbtu per day from November 2011 to October 2012. Please refer to Note 7 in the Notes to the Consolidated Financial Statements for full details of ARC's risk management positions as of March 31, 2010.
(3) The natural gas positions for 2011 extend until Dec 31, 2013 for the same volume and price levels.

Table 12 should be interpreted as follows, using the first quarter 2010 crude oil hedges as an example. To accurately analyze ARC's hedge position, contracts need to be modeled separately as using average prices and volumes may be misleading. The following provides examples of how the chart above can be interpreted for approximate values for the second quarter of 2010:

- If the market price is below $60 per barrel, ARC will receive $76.67 per barrel less the difference between $60 per barrel and the market price on 4,000 barrels per day. For example if the market price is at $55 per barrel ARC will receive $71.67 per barrel on 4,000 barrels per day and $76.67 per barrel on 11,000 barrels per day.
- If the market price is between $60 per barrel and $76.67 per barrel, ARC will receive $76.67 per barrel on 15,000 barrels per day.
- If the market price is between $76.67 per barrel and $92 per barrel, ARC will receive the market price on 15,000 barrels per day.
- If the market price exceeds $92 per barrel, ARC will receive $92 per barrel on 15,000 barrels per day.

Operating Netbacks
ARC's operating netback, before realized hedging gains and losses, increased 56 per cent to $33.07 per boe in the first quarter of 2010 compared to $21.16 per boe in the same period of 2009. The increase in netbacks is due mainly to the increase in commodity prices and a reduction in operating costs partially offset by an increase in royalties in the period.

ARC's first quarter 2010 netback, after realized hedging gains and losses, was $33.06 per boe, a 43 per cent increase from the same period in 2009. The 2010 netback includes net losses recorded on ARC's crude oil and natural gas risk management contracts during the quarter of $0.01 per boe compared to a net gain of $1.97 per boe recorded for the same period in 2009.

The components of operating netbacks are summarized in Table 13:

Table 13

Netbacks ($ per boe)	Crude Oil ($/bbl)	Heavy Oil ($/bbl)	Gas ($/mcf)	NGL ($/bbl)	**Q1 2010 Total ($/boe)**	Q1 2009 Total ($/boe)
Weighted average sales price	76.57	67.50	5.42	60.33	**51.85**	38.40
Other revenue	-	-	-	-	**0.08**	0.17
Total revenue	76.57	67.50	5.42	60.33	**51.93**	38.57
Royalties	(13.34)	(8.61)	(0.69)	(18.79)	**(8.58)**	(6.34)
Transportation	(0.14)	(0.97)	(0.28)	-	**(0.99)**	(0.95)
Operating costs (1)	(11.15)	(11.19)	(1.36)	(6.15)	**(9.29)**	(10.12)
Netback prior to hedging	51.94	46.73	3.09	35.39	**33.07**	21.16
Realized (loss) gain on risk management contracts (2)	(0.11)	-	0.01	-	**(0.01)**	1.97
Netback after hedging	51.83	46.73	3.10	35.39	**33.06**	23.13

(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.
(2) Realized (loss) gain on risk management contracts include the settlement amounts for crude oil and natural gas and power contracts. Foreign exchange and interest contracts are excluded from the net back calculation.

Royalties as a percentage of pre-hedged commodity revenue net of transportation remained consistent at 16.8 per cent ($8.58 per boe) in the first quarter of 2010 compared to 16.8 per cent ($6.34 per boe) in 2009.

The Alberta Royalty Framework ("Framework" or "ARF") took effect January 1, 2009 and provides for sliding scale crown royalty rates, whereby rates increase in high commodity price environments and decrease in low commodity price environments. The 2010 royalty rate is in line with management's expectations due to the low natural gas price environment. While gas prices have been consistent during the first quarter of 2010 as compared to first quarter of 2009, natural gas crown royalty payments have been lower as a result of the reduced royalty rate incentive on new wells that became effective April 1, 2009.

Royalty rates in the other western provinces vary with production levels and price but to a lesser extent than Alberta royalty rates. Table 14 estimates the royalties applicable to production from ARC's properties at various price levels.

Table 14

Royalty Rates - Forecast for 2010			
Edmonton posted oil (Cdn/$/bbl) (1)	**$60**	**$80**	**$100**
AECO natural gas (Cdn$/mcf) (1)	**$4.00**	**$5.50**	**$6.50**
Alberta royalty rate	12.6%	18.1%	22.6%
Saskatchewan royalty rate (2)	17.9%	17.9%	17.9%
British Columbia royalty rate (2)	17.0%	17.0%	17.0%
Manitoba royalty rate (2)	13.0%	13.0%	13.0%
Total Corporate Royalty Rate	**14.6%**	**17.8%**	**20.4%**

(1) Before quality differentials.
(2) Royalty rate includes Crown, freehold and gross override royalties for all jurisdictions in which ARC operates.

Following the implementation of the ARF, the Alberta Government introduced certain transitional rates and incentive programs to provide royalty relief to producers and to encourage continued drilling activity in the Province. ARC will be eligible for the Alberta programs assuming the necessary criteria are met and required elections are filed. The drilling credit program applies to new wells drilled between April 1, 2009 and March 31, 2011. As at March 31, 2010, ARC has received or accrued credits of $8.1 million and estimates it will generate a maximum $15.5 million credit over the life of the program based on forward looking prices. ARC is automatically eligible for the reduced royalty rate incentive on new production for wells coming on production between April 1, 2009 and March 31, 2011. These wells will receive a crown royalty rate of five per cent subject to certain production limits. During the first quarter of 2010 the Alberta government announced results of their competitive review that resulted in changes to some of the existing programs. These changes will come into effect January 1, 2011.

During 2009, the British Columbia government announced a new stimulus package designed to attract investment and produce immediate economic benefits for the province. The stimulus package included royalty incentives in the form of reduced royalty rates for wells drilled in the province between September 1, 2009 and June 30, 2010 and modifications to the existing deep well drilling program to increase available credits and expand depth criteria whereby additional wells may qualify for the program. ARC estimates that the deep well drilling credits could save approximately $1 million per horizontal well drilled. These credits will be recorded as a reduction to royalty expense to the extent that royalties are incurred on the well drilled. The royalty reduction program will result in a two per cent maximum royalty rate for a period of 12 months. Management estimates that for wells that do not qualify for the drilling credit program, the reduced royalty incentive could generate savings of $1 million per well at natural gas prices of $3 per mcf to $2.5 million per well at natural gas prices of $7 per mcf. Wells that qualify for the drilling credit program must draw down the drilling credit before qualifying for the reduced royalty program. Management plans to drill wells in British Columbia on operated properties during the incentive period in order to maximize the total benefit to ARC and its unitholders. New wells drilled that will qualify for the two per cent royalty incentive are expected to come on production in the third and fourth quarters of 2010.

Operating costs decreased to $9.29 per boe compared to $10.12 per boe in the first quarter of 2009. Despite a four per cent increase in production, total operating costs decreased $2.9 million, or five per cent in the first quarter of 2010 as compared to the first quarter of 2009 primarily attributed to lower power costs and cost savings and efficiencies achieved by the operations team.

General and Administrative ("G&A") Expenses and Long-term Incentive Compensation
G&A, prior to long-term incentive payments under the Whole Unit Plan and net of overhead recoveries on operated properties, increased 52 per cent to $15.7 million in the first quarter of 2010 from $10.3 million in 2009. The increase in G&A was primarily due to a special performance bonus of $2.8 million paid to ARC employees as approved by the Board of Directors in recognition of exceptional 2009 results. In addition, overhead recoveries decreased by $1.1 million relative to the first quarter of 2009 as a result of the timing and nature of capital expenditures incurred between the two comparative quarters.

A cash payment was made under the Whole Unit Plan in March 2010 for $15.1 million, of which $11 million was recorded in G&A with the remaining $4.1 million recorded to operating costs and capital projects. The next cash payment under the Whole Unit Plan is scheduled to occur in September 2010.

Table 15 is a breakdown of G&A and incentive compensation expense under the Whole Unit Plan:

Table 15

	Three Months Ended March 31		
G&A and Trust Unit Incentive Compensation Expense ($ millions except per boe)	**2010**	2009	% Change
G&A expenses	**19.0**	14.7	29
Operating recoveries	**(3.3)**	(4.4)	25
Cash G&A expenses before Whole Unit Plan	**15.7**	10.3	52
Cash Expense – Whole Unit Plan	**11.0**	5.6	96
Cash G&A expenses including Whole Unit Plan	**26.7**	15.9	68
Accrued compensation - Whole Unit Plan	**(5.5)**	(10.8)	49
Total G&A and incentive compensation expense	**21.2**	5.1	316
Total G&A and incentive compensation expense per boe	**3.50**	0.87	302

A non-cash Whole Unit Plan recovery of $5.5 million ($0.91 per boe) was recorded in the first quarter of 2010 compared to a recovery of $10.8 million ($1.85 per boe) in 2009. The recovery in 2010 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 at March 31, 2010 due to a decrease in units outstanding under the Whole Unit Plan. The 2009 non-cash amount relates to a decrease in the liability of the units outstanding under the Whole Unit Plan due to the decrease in the trust unit price relative to the closing price of the trust units at December 31, 2008.

Whole Unit Plan
The Whole Unit Plan is designed to offer each employee, officer and director (the "plan participants") 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 total return performance of ARC compared to its peers. Total return is calculated as a sum of the change in the market price of the trust units in the period plus the amount of distributions in the period. A performance multiplier is applied to the PTUs based on the percentile rank of ARC's total unitholder return compared to its peers. The performance multiplier ranges from zero, if ARC's performance ranks in the bottom quartile, to two for top quartile performance.

Table 16 shows the changes to the Whole Unit Plan during the first three months of 2010 along with the estimated value upon vesting of the plan as at March 31, 2010:

Table 16

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	1,052	1,305	2,357
Granted in the period	219	134	353
Vested in the period	(249)	(151)	(400)
Forfeited in the period	(15)	(21)	(36)
Balance, end of period (1)	1,007	1,267	2,274
Estimated distributions to vesting date (2)	166	285	451
Estimated units upon vesting after distributions	1,173	1,552	2,725
Performance multiplier (3)	-	1.1	-
Estimated total units upon vesting	1,173	1,701	2,874
Trust unit price at March 31, 2010	20.50	20.50	20.50
Estimated total value upon vesting ($ millions)	24.0	34.9	58.9

(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 1.1 at March 31, 2010 based on an average calculation of all outstanding grants. The performance multiplier is assessed each period end based on actual results of ARC 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, ARC's G&A expense is subject to significant volatility.

Table 17 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 under the Whole Unit Plan as at March 31, 2010:

Table 17

Value of Whole Unit Plan as at March 31, 2010	Performance multiplier		
(units thousands and $ millions except per unit)	**-**	**1.0**	**2.0**
Estimated units to vest			
RTUs	1,173	1,173	1,173
PTUs	-	1,552	3,104
Total units (1)	**1,173**	**2,725**	**4,277**
Trust unit price (2)	20.50	20.50	20.50
Trust unit distributions per month (2)	0.10	0.10	0.10
Value of Whole Unit Plan upon vesting (3)	**24.0**	**55.9**	**87.7**
2010	5.2	9.9	14.7
2011	9.8	18.5	27.1
2012	7.2	22.4	37.5
2013	1.8	5.1	8.4

(1) Includes additional estimated units to be issued under the Whole Unit Plan 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 $20.50 and $0.10 per trust unit distributions based on the unit price and distribution levels in place at March 31, 2010.
(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, ARC estimates that between $24 million and $87.7 million will be paid out from 2010 through 2013 based on the current trust unit price, distribution levels and ARC's market performance relative to its peers.

Interest and financing charges

Interest and financing charges increased to $11 million in the first quarter of 2010 from $5.8 million in 2009 due to a make whole payment on the early retirement of US$58.5 million of ARC's 2004 senior secured notes. As at March 31, 2010, ARC has $597.2 million of long-term debt outstanding, of which $323.1 million was fixed at a weighted average interest rate of six per cent. $274.1 million, including the working capital facility, has a floating interest rate at current market rates plus a credit spread of 60 to 65 basis points. Approximately 60 per cent (US$349.6 million) of the Trust's debt outstanding is denominated in U.S. dollars. ARC's credit facility is a three year facility maturing in April 2011. Management is currently considering a range of refinancing options that include renewing its bank facilities as well as issuing debt. Current expectation is that the current credit spread could increase upon renewal to 150 to 250 basis points.

Foreign Exchange Gains and Losses

ARC recorded a gain of $10.8 million in the first quarter of 2010 on foreign exchange transactions compared to a loss of $14.6 million in 2009. These amounts include both realized and unrealized foreign exchange gains and losses.

Table 18 shows the various components of foreign exchange gains and losses:

Table 18

Foreign Exchange Gains/Losses	Three Months Ended March 31		
($ millions)	**2010**	2009	% Change
Unrealized loss on U.S. denominated debt	**(9.3)**	(14.4)	35
Realized gain on U.S. denominated debt	**20.8**	-	100
Realized loss on U.S. denominated transactions	**(0.7)**	(0.2)	(250)
Total foreign exchange gain (loss)	**10.8**	(14.6)	174

Realized foreign exchange gains or losses arise from U.S. denominated transactions such as interest payments, debt repayments and hedging settlements. During the first quarter of 2010, ARC realized a $20.8 million foreign exchange gain primarily resulting from the early retirement of US$58.5 million of ARC's 2004 senior secured notes. This debt repayment was financed with ARC's credit facility.

Unrealized foreign exchange gains and losses are due to the 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 item. From December 31, 2009 to March 31, 2010, the Cdn$/US$ exchange rate decreased from 1.05 to 1.02 resulting in an unrealized gain of $11.5 million on U.S. dollar denominated debt, offset by the removal of $20.8 million of realized foreign exchange gains from the unrealized foreign exchange balance. This results in a net unrealized foreign exchange loss of $9.3 million.

Taxes
In the first quarter of 2010, a future income tax expense of $21.3 million was recorded compared to a recovery of $12.2 million in 2009. The expense in 2010 was primarily attributable to temporary differences associated with unrealized gains on risk management contracts recorded during this period.

The corporate income tax rate applicable to 2010 is 28 per cent; however ARC and its subsidiaries did not pay any material cash income taxes for the first quarter of 2010. Currently, ARC's structure is such that 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 continues to develop a plan for converting ARC Energy Trust to a corporation on January 1, 2011. After the conversion, the corporation expects to allocate its cash flow to fund a portion of capital expenditures, periodic debt repayments, site reclamation expenditures, and cash payments to shareholders in the form of dividends. 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 for federal tax purposes, taxable income will be reduced or potentially eliminated for the initial period post conversion. The 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

Income Tax Pool type	Cdn$ millions at March 31, 2010	Annual deductibility
Canadian Oil and Gas Property Expense	947.1	10% declining balance
Canadian Development Expense	424.7	30% declining balance
Canadian Exploration Expense	95.4	100%
Un-depreciated Capital Cost	448.5	Primarily 25% declining balance
Non-Capital Losses	181.9	100%
Research and Experimental Expenditures	0.8	100%
Other	29.0	Various rates, 7% declining balance to 20%
Total Federal Tax Pools	**2,127.4**	
Additional Alberta Tax Pools	155.5	Various rates, 25% declining balance to100%
Total Federal and Provincial Pools	**2,282.9**	

After conversion, returns to shareholders are expected to be impacted by the reduction of cash flow required to pay current income taxes, if any. Over the long-term, we would expect Canadian investors who hold their trust units in a taxable account to be relatively indifferent on an after tax basis as to whether ARC is structured as a corporation or as a trust after 2010. 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 taxable years after 2010 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, ARC expects there will be an opportunity to convert trust units to shares of the new corporation in a non-taxable manner; however, unitholders 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 $16.80 per boe in the first quarter of 2010 from $16.68 per boe in the first quarter of 2009. ARC posted a large increase in proved reserves at year-end 2009; 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)	**2010**	2009	% Change
Depletion of oil and gas assets (1)	**99.2**	95.1	4
Accretion of asset retirement obligation (2)	**2.4**	2.3	4
Total DD&A	**101.6**	97.4	4
DD&A rate per boe	**16.80**	16.68	1

(1) Includes depletion of the capitalized portion of the asset retirement obligation that was capitalized to the property, plant and equipment 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

Capital expenditures, excluding acquisitions and dispositions, totaled $128.3 million in the first quarter of 2010 compared to $97.2 million in the same period of 2009. This amount was incurred on drilling and completions, geological, geophysical, and facilities expenditures.

Of the total amount spent in the first quarter, $59.7 million was spent on ARC's resource plays, including $41.4 million for the Montney resource play in Northeast British Columbia and $14.9 million for the Cardium resource play in Alberta. A total of $53.6 million was spent on ARC's conventional oil & gas properties, $4.1 million on ARC's enhanced oil recovery initiatives, and the balance of $10.9 million was spent on leasehold improvements for ARC's new office space in downtown Calgary. Total capital expenditures are forecast to be $610 million in 2010.

In addition to capital expenditures on development activities during the first quarter, ARC completed producing property acquisitions of $6.3 million.

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

Table 21

	Three Months Ended March 31		
Capital Expenditures ($ millions)	**2010**	2009	% Change
Geological and geophysical	**6.6**	2.8	136
Drilling and completions	**77.2**	68.5	13
Plant and facilities	**29.5**	25.1	18
Undeveloped land purchased at crown land sales	**3.9**	0.2	-
Other capital	**11.1**	0.6	-
Total capital expenditures before net acquisitions	**128.3**	97.2	32
Producing property acquisitions (1)	**6.3**	0.1	-
Undeveloped land property acquisitions	**-**	6.1	(100)
Producing property dispositions (1)	**-**	-	-
Undeveloped land property dispositions	**-**	-	-
Total capital expenditures and net acquisitions	**134.6**	103.4	30

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

Approximately 80 per cent of the $128.3 million capital program in the first quarter of 2010 was financed with cash flow from operating activities and proceeds from the distribution re-investment plan ("DRIP") compared to 64 per cent for the same period of 2009. 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, 2010			Three Months Ended March 31, 2009		
	Capital Expenditures	**Net Acquisitions**	**Total Expenditures**	Capital Expenditures	Net Acquisitions	Total Expenditures
Expenditures	**128.3**	**6.3**	**134.6**	97.2	6.2	103.4
Per cent funded by:						
Cash flow from operating activities	**68%**	**-**	**65%**	45%	-	42%
Proceeds from distribution re-investment plan ("DRIP")	**12%**	**-**	**11%**	19%	-	18%
Debt/(excess funding)	**20%**	**100%**	**24%**	36%	100%	40%
	100%	**100%**	**100%**	100%	100%	100%

Asset Retirement Obligation and Reclamation Fund

At March 31, 2010, ARC recorded an Asset Retirement Obligation ("ARO") of $151.3 million ($149.9 million at December 31, 2009) for the future abandonment and reclamation of ARC's properties. The estimated ARO includes assumptions in respect of actual costs to abandon wells or reclaim the property as well as annual inflation factors in order to calculate the undiscounted total future liability. A significant portion of the costs are projected to be incurred in years 2050 to 2060. The future liability is then discounted at a weighted average risk adjusted credit rate of 6.5 per cent to reflect ARC's cost of borrowing for the period ended March 31, 2010.

Included in the March 31, 2010 ARO balance is a $0.5 million increase related to development activities and changes in estimates in the first three months of 2010, $2.4 million for accretion expense in the period and a reduction of $1.5 million for actual abandonment expenditures incurred in the first three months of 2010.

ARC has established two reclamation funds to finance future asset retirement obligations; one fund has been restricted to finance obligations specifically associated with the Redwater property, with the general fund financing all other obligations. Future contributions for the two funds will vary over time in order to provide for the total estimated future abandonment and reclamation costs that are to be incurred upon abandonment of ARC's properties. Minimum contributions to the Redwater fund over the next 46 years will be approximately $86 million. The general fund has no minimum contribution requirement; however, the Board of Directors has approved voluntary contributions that currently result in annual contributions of $6 million.

ARC's reclamation funds totaled $30.2 million as at March 31, 2010, compared to $33.2 million as at December 31, 2009. Under the terms of ARC'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 ARC's capital structure is outlined in Table 23, as at March 31, 2010 and December 31, 2009:

Table 23

Capital Structure and Liquidity ($ millions except per cent and ratio amounts)	**March 31, 2010**	December 31, 2009
Long-term debt	**597.2**	846.1
Working capital deficit (1)	**80.6**	56.3
Net debt obligations (2)	**677.8**	902.4
Market value of trust units and exchangeable shares (3)	**5,182.4**	4,765.7
Total capitalization (4)	**5,860.2**	5,668.1
Net debt as a percentage of total capitalization	**11.6%**	15.9%
Net debt to annualized YTD cash flow from operating activities	**1.1**	1.8

(1) Working capital deficit is calculated as current liabilities less the current assets as they appear on the Consolidated Balance Sheets, and excludes current unrealized amounts pertaining to risk management contracts and the current portion of future income taxes.

(2) Net debt is a non-GAAP measure and therefore it may not be comparable with the calculation of similar measures for other entities.
(3) 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 $20.50 and $19.94 at March 31, 2010 and December 31, 2009, respectively.
(4) 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 ARC.

During the first quarter of 2010, ARC issued US$50 million of long-term notes under its Master Shelf agreement with a coupon rate of 4.98 per cent and an average life of seven years. Proceeds from the issuance were used to repay existing long-term debt.

At March 31, 2010, ARC had total credit facilities of $1.2 billion with $597.2 million currently drawn resulting in unused credit available of $646.3 million. The credit facilities are made up of a bank syndicate that includes 11 domestic and international banks, long-term notes, and a Master Shelf agreement with a U.S. institutional investor. ARC's debt agreements contain a number of covenants all of which were met as at March 31, 2010. 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.

ARC's long-term strategy is to keep debt at less than 2.0 times cash flow from operating activities and under 20 per cent of total capitalization. This strategy resulted in manageable debt to cash flow levels throughout 2009 and 2010 and has positioned ARC to remain well below the debt covenant levels of 3.0 times. In 2010, with the closing of the equity offering, debt to cash flow from operating activities ratio declined to 1.1 times from 1.8 times in 2009. The expectation is that an increase in production volumes will result in further declines in this ratio during the course of the year assuming commodity prices remain stable.

The weak global economic situation in 2008 and 2009 impacted ARC along with all other oil and gas entities by restricting access to capital and increasing borrowing costs. The credit situation improved dramatically during the third and fourth quarters of 2009 and the first quarter of 2010 in the three markets that ARC typically uses to raise capital: equity, bank debt and long-term notes.

Costs of borrowing under our bank credit facilities comprise two items: first, the underlying interest rate on Bankers' Acceptances (CDN dollar loans) or LIBOR rates (U.S. denominated borrowings) and second, ARC's credit spread. The credit spread to ARC in 2009 and 2010 ranged between 60 and 65 basis points. In addition to paying interest on the outstanding debt under the revolving syndicated credit facility, ARC is charged a standby fee for the amount of the undrawn facility currently equal to 13.5 basis points.

ARC also accesses long-term debt from large institutional investors by issuing long-term notes, normally with an average term of five to 10 years. The cost of this debt is based upon two factors: the current rate of long-term government bonds and ARC's credit spread. ARC's average interest rate on its outstanding long-term notes is currently six per cent.

ARC expects to finance its 2010 capital program with cash flow from operating activities, proceeds from the DRIP and existing credit capacity. If ARC undertakes any major acquisitions, management would expect to finance the transactions with a combination of debt and equity in a cost effective manner.

Unitholders' Equity
At March 31, 2010, there were 252.8 million trust units issued and issuable for exchangeable shares, an increase of 13.8 million trust units from December 31, 2009 due mostly to the issuance of 13 million trust units as part of an equity offering closed in January 2010. The equity offering was made concurrent with ARC's $180 million purchase of properties at Ante Creek, with gross and net proceeds of approximately $252 million and $240 million, respectively.

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 three months of 2010, ARC raised proceeds of $15.4 million and issued 0.8 million trust units pursuant to the DRIP at an average price of $20.16 per unit.

Distributions
In the first quarter of 2010, ARC declared distributions of $75 million ($0.30 per unit), representing 47 per cent of 2010 first quarter cash flow from operating activities compared to distributions of $82 million ($0.36 per unit) representing 66 per cent of cash flow from operating activities in the first quarter of 2009.

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

- a portion of capital expenditures;
- annual contribution to the reclamation funds;
- debt principal repayments;
- income tax if any; and
- certain obligations for future payments relative to the long-term incentive compensation under the Whole Unit Plan.

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 **2010** ($ millions)	2009	% Change	Three Months Ended March 31 **2010** ($ per unit)	2009	% Change
Cash flow from operating activities	**158.7**	124.3	28	**0.63**	0.54	17
Net reclamation fund withdrawals(1)	**3.0**	1.5	100	**0.01**	0.01	-
Capital expenditures funded with cash flow from operating activities	**(86.7)**	(43.8)	98	**(0.34)**	(0.19)	79
Other (2)	**-**	-	-	**-**	-	-
Distributions	**75.0**	82.0	(9)	**0.30**	0.36	(17)

(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.

ARC 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 ARC 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. ARC'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 ARC's financial flexibility is maintained by a review of ARC'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 ARC to use debt to finance these expenditures. In the first three months of 2010, ARC funded 80 per cent of capital development activities with a portion of cash flow from operating activities and DRIP proceeds. Distributions and the actual amount of cash flows withheld to fund ARC's capital expenditure program is dependent on the commodity price environment and is subject to the approval and discretion of the Board of Directors.

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 25 illustrates the comparison of distributions to net income as a measure of long-term sustainability. With the decline in commodity prices in 2009 relative to 2008, distributions were reduced from $0.15 per unit per month in December 2008, to $0.12 per unit per month in January 2009, and subsequently to the current rate of $0.10 per unit per month in May 2009.

Table 25

Net income and Distributions ($ millions except per cent and per unit amounts)	**First quarter 2010**	Full year 2009	Full year 2008
Net income	**139.4**	222.8	533.0
Distributions	**75.0**	298.5	570.0
Excess (Shortfall)	**64.4**	(75.7)	(37.0)
Excess (Shortfall) as per cent of net income	**46%**	(34%)	(7%)
Cash flow from operating activities	**158.7**	497.4	944.4
Distributions as a per cent of cash flow from operating activities	**47%**	60%	60%
Average distribution per unit per month	**$0.10**	$0.11	$0.22

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.

Table 26

Calendar Year	Distributions	Taxable Portion	Return of Capital
2010 YTD (2)	0.30	0.29	0.01
2009	1.28	1.24	0.04
2008	2.67	2.62	0.05
2007	2.40	2.32	0.08
2006(1)	2.60	2.55	0.05
2005	1.94	1.90	0.04
2004	1.80	1.69	0.11
2003	1.78	1.51	0.27
2002	1.58	1.07	0.51
2001	2.41	1.64	0.77
2000	1.86	0.84	1.02
1999	1.25	0.26	0.99
1998	1.20	0.12	1.08
1997	1.40	0.31	1.09
1996	0.81	-	0.81
Cumulative	**$ 25.28**	**$ 18.36**	**$ 6.92**

(1) Based on distributions paid and payable in 2006.
(2) Based on distributions declared at March 31, 2010 and estimated taxable portion of 2010 distributions of 97 per cent.

Please refer to ARC's website at www.arcresources.com for details of the monthly distribution amounts and distribution dates for 2010.

Taxation of Distributions
Distributions comprise a return of capital portion (tax deferred) and a return on capital portion (taxable). The return of capital component reduces the cost basis of the trust units held. For a more detailed breakdown, please visit our website at www.arcresources.com.

Environmental Initiatives Impacting ARC
There are no new environmental initiatives impacting ARC at this time.

Contractual Obligations and Commitments
ARC has contractual obligations in the normal course of operations including purchase of assets and services, operating agreements, transportation commitments, sales commitments, royalty obligations, lease rental obligations and employee agreements. These obligations are of a recurring, consistent nature and impact ARC's cash flows in an ongoing manner. ARC also has contractual obligations and commitments that are of a less routine nature as disclosed in Table 27.

Table 27

	Payments Due by Period				
($ millions)	1 year	2–3 years	4-5 years	Beyond 5 years	Total
Debt repayments (1)	26.4	326.3	91.0	153.5	597.2
Interest payments (2)	19.1	34.5	25.6	24.1	103.3
Reclamation fund contributions (3)	4.9	8.9	7.7	64.2	85.7
Purchase commitments	62.3	34.9	12.6	13.3	123.1
Transportation commitments (4)	6.6	28.5	21.4	5.7	62.2
Operating leases	2.9	14.7	15.0	72.4	105.0
Risk management contract premiums (5)	2.3	1.8	-	-	4.1
Total contractual obligations	124.5	449.6	173.3	333.2	1,080.6

(1) Long-term and short-term debt.
(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 the second quarter of 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, ARC has commitments related to its risk management program (see Note 7 of the unaudited Consolidated Financial Statements). As the premiums are part of the underlying risk management contract, they have been recorded at fair market value at March 31, 2010 on the balance sheet as part of risk management contracts.

ARC enters into commitments for capital expenditures in advance of the expenditures being made. At any given point in time, it is estimated that ARC 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. ARC's 2010 capital budget has been approved by the Board at $610 million. This commitment has not been disclosed in the commitment table (Table 27) as it is of a routine nature and is part of normal course of operations for active oil and gas companies and trusts.

ARC 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 ARC's financial position or results of operations and therefore the commitment table (Table 27) does not include any commitments for outstanding litigation and claims.

ARC has certain sales contracts with aggregators whereby the price received by ARC is dependent upon the contracts entered into by the aggregator. This commitment has not been disclosed in the commitment table (Table 27) as it is of a routine nature and is part of normal course of operations.

Off Balance Sheet Arrangements

ARC has certain lease agreements, all of which are reflected in the Contractual Obligations and Commitments table (Table 27), 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 on the balance sheet as of March 31, 2010.

Critical Accounting Estimates

ARC has continuously refined and documented its management and internal reporting systems to ensure that accurate, timely, internal and external information is gathered and disseminated.

ARC'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 ARC 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.

ARC 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 ARC's environmental, health and safety policies.

Assessment of Business Risks
The ARC management team is focused on long-term strategic planning and has identified the key risks, uncertainties and opportunities associated with ARC's business that can impact the financial results. They include, but are not limited to:

- volatility of oil and natural gas prices;
- refinancing and debt service;
- counterparty risk;
- variations in interest rates and foreign exchange rates;
- reserves estimates;
- changes in income tax legislation;
- changes in government royalty legislation;
- acquisitions;
- environmental concerns and impact on enhanced oil recovery projects;
- operational matters;
- depletion of reserves and maintenance of distribution; and
- project risks.

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, 2010 requires that ARC disclose in the interim MD&A any changes in ARC's internal control over financial reporting that occurred during the period that has materially affected, or is reasonably likely to materially affect ARC's internal control over financial reporting. ARC confirms that no such changes were made to the internal controls over financial reporting during the first three months of 2010.

Financial Reporting Update
International Financial Reporting Standards ("IFRS")

In October 2009, the Accounting Standards Board issued a third and final IFRS Omnibus Exposure Draft confirming that publicly accountable enterprises will be required to apply IFRS, in full and without modification, for all financial periods beginning January 1, 2011. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by ARC for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010.

In 2008, ARC commenced the process to transition its financial statements from current Canadian GAAP to IFRS, and has been progressing towards completion throughout 2009 and into 2010. ARC's project consists of three key phases: the scoping and diagnostic phase, the impact analysis and evaluation phase and the implementation phase. A wholesome description of ARC's IFRS project phases and ARC's progress to the end of 2009 is contained within ARC's MD&A for the year ended December 31, 2009.

Management has not yet finalized its chosen IFRS accounting policies and as such is unable to quantify the impact of adopting IFRS on its financial statements. In accordance with its transition plan, ARC is continuing the process of evaluating its accounting policy choices, quantifying their expected effects and making recommendations of chosen accounting policies to senior management for approval and presenting to the audit committee of the Board of Directors for their review.

First Time Adoption of IFRS

IFRS 1 provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions in certain areas to the general requirement for full retrospective application of IFRS. Management is analyzing the various accounting policy choices available and will implement those determined to be the most appropriate for ARC which at this time are summarized as follows:

- Property Plant and equipment ("PP&E") – IFRS 1 provides the option to value the PP&E assets at their deemed cost being the Canadian GAAP net book value assigned to these assets as at the date of transition, January 1, 2010. This amendment is permissible for entities such as ARC who follow the full cost accounting guideline under Canadian GAAP that accumulates all oil and gas assets into one cost centre. Under IFRS, ARC's PP&E assets must be divided into smaller cost centres. The net book value of the assets on the date of transition will be allocated to the new cost centres on the basis of ARC's reserve volumes or values at that point in time.

- Business Combinations – IFRS 1 allows ARC to use the IFRS rules for business combinations on a prospective basis rather that re-stating all business combinations. The IFRS business combination rules converge with the new CICA Handbook section 1582 that is also effective for ARC on January 1, 2011, however earlier adoption is permitted.

The transition from Canadian GAAP to IFRS is a significant undertaking that may materially affect our reported financial position and results of operations. At this time, ARC has identified key differences that will impact the financial statements as follows:

- Re-classification of Exploration and Evaluation ("E&E") expenditures from PP&E – Upon transition to IFRS, ARC will reclassify all E&E expenditures that are currently included in PP&E on the Consolidated Balance Sheet. This consists of the book value for ARC's undeveloped land that relates to exploration properties. E&E assets will not be depleted and must be assessed for impairment when indicators suggest the possibility of impairment.
- Calculation of depletion expense for PP&E assets – Upon transition to IFRS, ARC has the option to calculate depletion using a reserve base of proved reserves or both proved and probable reserves, as compared to the Canadian GAAP method of calculating depletion using only proved reserves. ARC has not concluded at this time which method for calculating depletion will be used.
- Impairment of PP&E assets – Under IFRS, impairment of PP&E must be calculated at a more granular level than what is currently required under Canadian GAAP. Impairment calculations will be performed at the cash generating unit level using either total proved or proved plus probable reserves.
- Provisions for asset retirement costs – Under IFRS, ARC is required to revalue its entire liability for asset retirement costs at each balance sheet date using a current liability-specific discount rate. Under Canadian GAAP, once recorded, asset retirement obligations are not adjusted for future changes in discount rates.

In addition to accounting policy differences, ARC's transition to IFRS is expected to impact its internal controls over financial reporting, disclosure controls and procedures, certain of ARC's business activities and IT systems as follows:

- Internal controls over financial reporting ("ICFR") – As the review of ARC's accounting policies is completed, an assessment will be made to determine changes required for ICFR. As an example, additional controls will be implemented for the IFRS 1 changes such as the allocation of ARC's PP&E as well as the process for reclassifying ARC's E&E expenditures from PP&E. This will be an ongoing process throughout 2010 to ensure that all changes in accounting policies include the appropriate additional controls and procedures for future IFRS reporting requirements.

- Disclosure controls and procedures – Throughout the transition process, ARC will be assessing its stakeholders' information requirements and will ensure that adequate and timely information is provided to meet these needs. Management plans to deliver investor presentations during the second half of 2010 to explain the differences between the historical Canadian GAAP statements and the IFRS statements.

- Business activities – Management has been cognizant of the upcoming transition to IFRS and as such has worked with its counterparties and lenders to ensure that any agreements that contain references to Canadian GAAP financial statements are modified to allow for IFRS statements. Based on the expected changes to ARC's accounting policies at this time, no issues are expected with the existing wording of debt covenants and related agreements as a result of the conversion to IFRS. During the 2010 quarterly meetings held with ARC's lenders there will be an update on IFRS as it relates to ARC and management will continue to monitor these areas closely as final policy choices are made.

- IT systems – ARC has completed most of the accounting system updates required in order to ready the company for IFRS reporting. The modifications were not significant, however, deemed critical in order to allow for reporting of both Canadian GAAP and IFRS statements in 2010 as well as the modifications required to track PP&E and E&E expenditures at a more granular level of detail for IFRS reporting. Additional system modifications may be required based on final policy choices.

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 ARC. 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 MD&A 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 MD&A contains forward-looking information and statements pertaining to the following: all of the matters under the heading "2010 Guidance and Financial Highlights" which contains guidance for 2010, the future expenditure plans for 2010 and expected production under the heading "Production", the expectations regarding the pricing of natural gas for 2010 under the heading “Commodity Prices Prior to Hedging”, the expected benefits from various incentive plans instituted in the provinces of Alberta and British Columbia and future operating costs under the heading "Operating Netbacks", the increase in interest rates in 2010 as a result of the renewal of our credit facility under the heading "Interest and Financing Charges"; the plans for converting ARC Energy Trust to a corporation and the payment of income taxes in the future by ARC and the availability of a non-taxable conversion of trust units to shares on the conversion of the trust structure to a corporation under the heading "Taxes", the information relating to financing the 2010 capital expenditures under the heading: "Capitalization, Financial Resources and Liquidity", the expectations related to the transition from Canadian GAAP to IFRS under the heading “Financial Reporting Update”, and a number of other matters, including 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; and future development, exploration, acquisition and development activities (including drilling plans) and related capital expenditures.

The forward-looking information and statements contained in this MD&A 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 MD&A 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 MD&A and in ARC's Annual Information Form).

The forward-looking information and statements contained in this MD&A speak only as of the date of this MD&A, 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.

QUARTERLY HISTORICAL REVIEW

(Cdn $ millions, except per unit amounts)	2010	2009				2008		
FINANCIAL	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Revenue before royalties	314.1	278.6	239.2	235.2	225.2	300.8	485.7	512.0
Per unit (1)	1.25	1.17	1.01	0.99	0.98	1.38	2.24	2.38
Cash flow from operating activities	158.7	143.2	125.6	104.3	124.3	209.4	251.4	273.4
Per unit – basic (1)	0.63	0.60	0.53	0.44	0.54	0.96	1.16	1.27
Per unit - diluted	0.63	0.60	0.53	0.44	0.54	0.96	1.16	1.27
Net income	139.4	65.5	68.9	66.1	22.3	82.7	311.7	57.3
Per unit – basic (2)	0.56	0.28	0.29	0.28	0.10	0.38	1.46	0.27
Per unit - diluted	0.56	0.28	0.29	0.28	0.10	0.38	1.46	0.27
Distributions	75.0	70.9	70.6	75.0	82.0	127.2	171.3	144.7
Per unit – basic (3)	0.30	0.30	0.30	0.32	0.36	0.59	0.80	0.68
Total assets	4,020.1	3,914.5	3,642.9	3,672.5	3,733.1	3,766.7	3,687.5	3,664.3
Total liabilities	1,322.4	1,540.1	1,278.4	1,323.1	1,392.1	1,624.6	1,530.8	1,689.6
Net debt outstanding (4)	677.8	902.4	705.4	737.6	781.5	961.9	773.2	756.1
Weighted average trust units (5)	251.8	238.5	237.7	236.6	228.9	218.3	216.6	215.2
Trust units outstanding and issuable (5)	252.8	239.0	238.1	237.1	236.0	219.2	217.4	215.8
CAPITAL EXPENDITURES								
Geological and geophysical	6.6	2.9	3.0	5.0	2.8	3.7	1.3	16.4
Land	3.9	2.0	4.5	0.2	0.2	17.1	18.6	57.8
Drilling and completions	77.2	66.1	61.0	18.6	68.5	117.1	91.4	32.6
Plant and facilities	29.5	35.3	26.1	23.6	25.1	30.5	24.2	24.1
Other capital	11.1	11.0	1.6	1.5	0.6	1.0	0.9	0.4
Total capital expenditures	128.3	117.3	96.2	48.9	97.2	169.4	136.4	131.3
Property acquisitions (dispositions) net	6.3	1.1	(30.1)	2.3	6.2	27.6	13.1	0.3
Corporate acquisitions	-	178.9	-	-	-	-	-	-
Total capital expenditures and net	134.6	297.3	66.1	51.2	103.4	197.0	149.5	131.6
OPERATING								
Production								
Crude oil (bbl/d)	27,640	27,415	26,921	26,917	28,806	28,935	28,509	27,541
Natural gas (mmcf/d)	217.9	189.0	193.1	200.2	193.8	195.1	192.0	194.7
Natural gas liquids (bbl/d)	3,252	3,597	3,717	3,679	3,764	3,858	3,822	3,906
Total (boe per day 6:1)	67,207	62,520	62,824	63,969	64,872	65,313	64,325	63,896
Average prices								
Crude oil ($/bbl)	76.26	72.61	67.74	62.74	46.44	56.26	114.20	118.32
Natural gas ($/mcf)	5.42	4.58	3.25	3.73	5.20	7.48	8.68	10.41
Natural gas liquids ($/bbl)	60.33	46.12	38.92	38.89	38.86	45.22	82.87	82.29
Oil equivalent ($/boe)	51.85	48.35	41.31	40.32	38.40	49.93	81.42	87.73
TRUST UNIT TRADING PRICES								
(based on intra-day trading)								
High	22.49	21.89	20.20	19.25	20.90	22.55	33.30	33.95
Low	19.80	19.06	15.48	14.12	11.73	15.01	22.33	25.19
Close	20.50	19.94	20.20	17.81	14.15	20.10	23.10	33.95
Average daily volume (thousands)	1,287	963	1,038	988	1,240	1,523	841	659

(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) 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).
(3) Based on number of trust units outstanding at each distribution date.
(4) Net debt excludes the current unrealized risk management contracts asset and liability and the current portion of future income taxes.
(5) 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)		**2010**		2009
ASSETS				
Current assets				
Cash and cash equivalents	**$**	**0.3**	$	-
Accounts receivable (Note 2)		**123.6**		115.9
Prepaid expenses		**18.5**		18.2
Risk management contracts (Note 7)		**41.3**		5.9
Future income taxes		**-**		7.1
		183.7		147.1
Reclamation funds		**30.2**		33.2
Risk management contracts (Note 7)		**38.9**		3.2
Property, plant and equipment		**3,609.7**		3,573.4
Goodwill		**157.6**		157.6
Total assets	**$**	**4,020.1**	$	3,914.5
LIABILITIES				
Current liabilities				
Accounts payable and accrued liabilities	**$**	**197.9**	$	166.7
Distributions payable		**25.1**		23.7
Risk management contracts (Note 7)		**1.3**		12.9
Future income taxes		**6.1**		-
		230.4		203.3
Risk management contracts (Note 7)		**-**		1.0
Long-term debt (Note 4)		**597.2**		846.1
Accrued long-term incentive compensation (Note 12)		**9.0**		10.9
Asset retirement obligations (Note 5)		**151.3**		149.9
Future income taxes		**334.5**		328.9
Total liabilities		**1,322.4**		1,540.1
COMMITMENTS AND CONTINGENCIES (Note 13)				
NON-CONTROLLING INTEREST				
Exchangeable shares (Note 8)		**37.1**		36.0
UNITHOLDERS' EQUITY				
Unitholders' capital (Note 9)		**3,175.4**		2,917.6
Deficit (Note 10)		**(514.2)**		(578.6)
Accumulated other comprehensive loss (Note 10)		**(0.6)**		(0.6)
Total unitholders' equity		**2,660.6**		2,338.4
Total liabilities and unitholders' equity	**$**	**4,020.1**	$	3,914.5

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)		2010		2009
REVENUES				
Oil, natural gas and natural gas liquids	**$**	**314.1**	$	225.2
Royalties		**(51.9)**		(37.0)
		262.2		188.2
Gain (loss) on risk management contracts (Note 7)				
Realized		**1.3**		16.3
Unrealized		**83.7**		(6.6)
		347.2		197.9
EXPENSES				
Transportation		**6.0**		5.6
Operating		**56.2**		59.1
General and administrative		**21.2**		5.1
Interest and financing charges (Note 4)		**11.0**		5.8
Depletion, depreciation and accretion		**101.6**		97.4
(Gain) loss on foreign exchange		**(10.8)**		14.6
		185.2		187.6
Future income tax (expense) recovery		**(21.3)**		12.2
Net income before non-controlling interest		**140.7**		22.5
Non-controlling interest (Note 8)		**(1.3)**		(0.2)
Net income	**$**	**139.4**	$	22.3
Deficit, beginning of period	**$**	**(578.6)**	$	(502.9)
Distributions paid or declared (Note 11)		**(75.0)**		(82.0)
Deficit, end of period (Note 10)	**$**	**(514.2)**	$	(562.6)
Net income per unit (Note 9)				
Basic and Diluted	**$**	**0.56**	$	0.10

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)		**2010**		2009
Net income	**$**	**139.4**	$	22.3
Other comprehensive income (loss), net of tax				
Losses on financial instruments designated as cash flow hedges [1]		**(0.1)**		(2.1)
Gains and losses on financial instruments designated as cash flow hedges in prior periods realized in net income in the current period [2] (Note 7)		**0.1**		(0.1)
Net unrealized gains (losses) on available-for-sale reclamation funds' investments [3]		**-**		(0.1)
Other comprehensive income (loss)		**-**		(2.3)
Comprehensive income	**$**	**139.4**	$	20.0
Accumulated other comprehensive (loss) income, beginning of period		**(0.6)**		1.9
Other comprehensive income (loss)		**-**		(2.3)
Accumulated other comprehensive loss, end of period (Note 10)	**$**	**(0.6)**	$	(0.4)

(1) Nominal future income tax impact for the period ended March 31, 2010 (net of tax of $0.7 million for the period ended March 31, 2009).
(2) Nominal future income tax impact for the three month period ended March 31, 2010 and March 31, 2009.
(3) Nominal future income tax impact for the three month period ended March 31, 2010 and March 31, 2009.

See accompanying notes to the Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

For the three months ended March 31

(Cdn$ millions)	**2010**	2009
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	**$ 139.4**	$ 22.3
Add items not involving cash:		
Non-controlling interest (Note 8)	**1.3**	0.2
Future income tax expense (recovery)	**21.3**	(12.2)
Depletion, depreciation and accretion	**101.6**	97.4
Non-cash (gain) loss on risk management contracts (Note 7)	**(83.7)**	6.6
Non-cash (gain) loss on foreign exchange	**(11.5)**	14.4
Non-cash trust unit incentive compensation recovery (Note 12)	**(6.4)**	(12.1)
Expenditures on site restoration and reclamation (Note 5)	**(1.5)**	(1.7)
Change in non-cash working capital	**(1.8)**	9.4
	158.7	124.3
CASH FLOWS FROM FINANCING ACTIVITIES		
Repayment of long-term debt under revolving credit facilities, net	**(229.7)**	(212.4)
Issue of Senior Secured Notes	**51.4**	-
Repayment of Senior Secured Notes	**(59.4)**	-
Issue of trust units, net of issue costs	**240.1**	240.6
Cash distributions paid (Note 11)	**(58.8)**	(68.2)
Change in non-cash working capital	**2.7**	1.9
	(53.7)	(38.1)
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisition of petroleum and natural gas properties	**(6.3)**	(6.2)
Capital expenditures	**(129.3)**	(99.3)
Net reclamation fund withdrawals	**3.0**	1.5
Change in non-cash working capital	**27.9**	(22.2)
	(104.7)	(126.2)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**0.3**	(40.0)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	**-**	40.0
CASH AND CASH EQUIVALENTS, END OF PERIOD	**$ 0.3**	$ -

See accompanying notes to the Consolidated Financial Statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

March 31, 2010 and 2009
(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. 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 ARC's 2009 annual report.

2. FINANCIAL ASSETS AND CREDIT RISK

Credit risk is the risk of financial loss to ARC if a partner or counterparty to a product sales contract or financial instrument fails to meet its contractual obligations. ARC is exposed to credit risk with respect to its cash equivalents, accounts receivable, reclamation funds, and risk management contracts. Most of ARC's accounts receivable relate to oil and natural gas sales and are subject to typical industry credit risks. ARC 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 ARC's credit policy; and
- 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, 2010 pertains to accrued revenue for March 2010 production volumes. ARC transacts with a number of oil and natural gas marketing companies and commodity end users ("commodity purchasers"). Commodity purchasers and marketing companies typically remit amounts to ARC 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, 2010, no one counterparty accounted for more than 25 per cent of the total accounts receivable balance and the largest commodity purchaser receivable balance is fully secured with Letters of Credit.

When determining whether amounts that are past due are collectable, management assesses the credit worthiness 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, 2010, $1.8 million of accounts receivable are past due, excluding amounts in ARC's allowance for doubtful accounts, all of which are considered to be collectable. The change in ARC's allowance for doubtful accounts for the period ended March 31, 2010 is nominal.

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.

3. FINANCIAL LIABILITIES AND LIQUIDITY RISK

Liquidity risk is the risk that ARC will not be able to meet its financial obligations as they become due. ARC 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 ARC's financial liabilities.

The following table details ARC's financial liabilities as at March 31, 2010:

($ millions)	1 year	2 - 3 years	4 - 5 years	Beyond 5 years	Total
Accounts payable and accrued liabilities [(1)]	205.5	-	-	-	205.5
Distributions payable [(2)]	20.2	-	-	-	20.2
Risk management contracts [(3)]	13.6	3.8	-	-	17.4
Senior secured notes and interest	41.2	91.0	116.6	177.6	426.4
Revolving credit facilities	-	269.8	-	-	269.8
Working capital facility	4.3	-	-	-	4.3
Accrued long-term incentive compensation [(1)]	-	34.6	-	-	34.6
Total financial liabilities	284.8	399.2	116.6	177.6	978.2

(1) Liabilities under the Whole Trust Unit Incentive 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 gross at their future value.

4. LONG-TERM DEBT

		March 31, 2010		December 31, 2009
Syndicated credit facilities:				
Cdn$ denominated	**$**	**208.9**	$	423.0
US$ denominated		**60.9**		74.3
Working capital facility		**4.3**		7.9
Senior secured notes:				
Master Shelf Agreement				
5.42% US$ Note		**76.2**		78.5
4.94% US$ Note		**6.1**		6.3
4.98% US$ Note		**50.8**		-
2004 Note Issuance				
4.62% US$ Note		**32.6**		54.5
5.10% US$ Note		**24.4**		65.4
2009 Note Issuance				
7.19% US$ Note		**68.5**		70.6
8.21% US$ Note		**35.5**		36.6
6.50% Cdn$ Note		**29.0**		29.0
Total long-term debt outstanding	**$**	**597.2**	$	846.1

Credit Facilities

ARC has an $800 million secured, annually extendible, financial covenant-based syndicated credit facility. The maturity date of the current syndicated credit facility is April 15, 2011. ARC also has in place a $25 million demand working capital facility. The working capital facility is also secured and is subject to the same covenants as the syndicated credit facility.

Borrowings under the syndicated credit facility bear interest at bank prime (2.25 per cent at March 31, 2010, 2.25 per cent at December 31, 2009) or, at ARC's option, Canadian dollar bankers' acceptances or U.S. dollar LIBOR loans, plus a stamping fee. These stamping fees vary between a minimum of 60 basis points ("bps") to a maximum of 110 bps.

During the first quarter of 2010, the weighted-average interest rate under the credit facility was 0.9 per cent (1.7 per cent in 2009).

Senior Secured Notes Issued Under a Master Shelf Agreement

The terms and rates of the senior secured notes issued under the Master Shelf Agreement are the same as those detailed at December 31, 2009, with the exception of a new tranche issued on March 5, 2010.

Issue Date	Remaining Principal	Coupon Rate	Maturity Date	Principal Payment Terms
March 5, 2010	US$50.0 million	4.98%	March 5, 2019	Five equal installments beginning March 5, 2015

Senior Secured Notes not Subject to the Master Shelf Agreement

In the first quarter of 2010, ARC elected to prepay US$58.5 million of outstanding principal on its 2004 Note Issuance. A make whole payment of US$4.8 million was made in conjunction with the note prepayment and is classified as interest and financing charges on the statement of income. The amendment to the 2004 Note agreements were made to align the key provisions in all outstanding senior secured note agreements.

The terms and rates of the remaining senior secured notes not subject to the Master Shelf Agreement are the same as those detailed at December 31, 2009. The remaining principal on the 2004 Notes are summarized below.

Issue Date	Remaining Principal	Coupon Rate	Maturity Date	Payment Terms
April 27, 2004	US$32.1 million	4.62%	April 27, 2014	Six equal installments beginning April 27, 2009
April 27, 2004	US$24.0 million	5.10%	April 27, 2016	Five equal installments beginning April 27, 2012

Credit Capacity
The following table summarizes ARC's available credit capacity and the current amounts drawn as at March 31, 2010:

	Credit Capacity	Drawn	Remaining
Syndicated Credit Facility	800.0	269.8	530.2
Working Capital Facility	25.0	4.3	20.7
Senior Secured Notes Subject to a Master Shelf Agreement(1)	228.5	133.1	95.4
Senior Secured Notes Not Subject to a Master Shelf Agreement	190.0	190.0	-
Total	1,243.5	597.2	646.3

(1) Total credit capacity is US$225 million.

Supplemental disclosures

The fair value of all senior secured notes as at March 31, 2010, is $333.6 million compared to a carrying value of $323.1 million ($347.3 million compared to $340.9 million as at December 31, 2009).

Amounts of US$21.8 million due under the senior secured notes and $4.3 million due under ARC'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 these amounts through the syndicated credit facility.

Interest paid during the first quarter of 2010 was $4.7 million less than interest expense ($1.4 million less in 2009).

5. ASSET RETIREMENT OBLIGATIONS

The following table reconciles ARC's asset retirement obligations:

	Three Months Ended March 31, 2010	Year Ended December 31, 2009
Balance, beginning of period	**$ 149.9**	$ 141.5
Increase in liabilities relating to corporate acquisitions	**-**	4.0
Increase in liabilities relating to development activities	**0.5**	1.7
Increase in liabilities relating to change in estimate	**-**	2.1
Settlement of reclamation liabilities during the period	**(1.5)**	(8.7)
Accretion expense	**2.4**	9.3
Balance, end of period	**$ 151.3**	$ 149.9

ARC's weighted average credit adjusted risk free rate as at March 31, 2010 was 6.5 per cent (6.5 per cent as at December 31, 2009).

6. CAPITAL MANAGEMENT

The objective of ARC when managing its capital is to maintain a conservative structure that will allow it to:

- Fund its development and exploration program;
- Provide financial flexibility to execute on strategic opportunities; and
- 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.

ARC 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 ARC's capital structure, management's objective is to limit net debt to less than two times annualized cash flow from operating activities and 20 per cent of total capitalization. As at March 31, 2010 ARC's net debt to annualized cash flow from operating activities ratio is 1.1 and its net debt to total capitalization ratio is 11.6 per cent.

($ millions, except per unit and per cent amounts)	March 31, 2010	December 31, 2009
Long-term debt	**597.2**	846.1
Accounts payable and accrued liabilities	**197.9**	166.7
Distributions payable	**25.1**	23.7
Cash and cash equivalents, accounts receivable and prepaid expenses	**(142.4)**	(134.1)
Net debt obligations (1)	**677.8**	902.4
Trust units outstanding and issuable for exchangeable shares (millions)	**252.8**	239.0
Trust unit price (2)	**20.50**	19.94
Market capitalization (1)	**5,182.4**	4,765.7
Net debt obligations (1)	**677.8**	902.4
Total capitalization (1)	**5,860.2**	5,668.1
Net debt as a percentage of total capitalization	**11.6%**	15.9%
Net debt obligations to annualized cash flow from operating activities	**1.1**	1.8

(1) Net debt obligations, market capitalization 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.

(2) TSX close price as at March 31, 2010 and December 31, 2009 respectively.

ARC manages its capital structure and makes adjustments to it in response to changes in economic conditions and the risk characteristics of the underlying assets. ARC 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 ARC is subject to various covenants under its credit facilities. Compliance with these covenants is monitored on a quarterly basis and as at March 31, 2010 ARC is in compliance with all covenants.

7. MARKET RISK MANAGEMENT

ARC is exposed to a number of market risks that are part of its normal course of business. ARC has a risk management program in place that includes financial instruments as disclosed in the risk management section of this note.

ARC's risk management program is overseen by its Risk Committee based on guidelines approved by the Board of Directors. The objective of the risk management program is to support ARC's business plan by mitigating adverse changes in commodity prices, interest rates and foreign exchange rates.

In the sections below, ARC has prepared sensitivity analyses in an attempt to demonstrate the effect of changes in these market risk factors on ARC's net income. For the purposes of the sensitivity analyses, the effect of a variation in a particular variable is calculated independently of any change in another variable. In reality, changes in one factor may contribute to changes in another, which may magnify or counteract the sensitivities.
For instance, trends have shown a correlation between the movement in the foreign exchange rate of the Canadian dollar relative to the U.S. dollar and the West Texas Intermediate posted ("WTI") crude oil price.

Commodity price risk

ARC's operational results and financial condition are largely dependent on the commodity prices received for its oil and natural gas production. Commodity prices have fluctuated widely during recent years due to global and regional factors including supply and demand fundamentals, inventory levels, weather, economic, and geopolitical factors. Movement in commodity prices could have a significant positive or negative impact on distributions to unitholders.

ARC manages the risks associated with changes in commodity prices by entering into a variety of risk management contracts (see Risk Management Contracts below). The following table illustrates the effects of movement in commodity prices on net income due to changes in the fair value of risk management contracts in place at March 31, 2010. The sensitivity is based on a US$15 per barrel increase and US$15 per barrel decrease in WTI and a $1.50 per mcf increase and $1.50 per mcf decrease in the price of AECO natural gas. The commodity price assumptions are based on Management's assessment of reasonably possible changes in oil and natural gas prices that could occur between March 31, 2010 and ARC's next reporting date.

	Increase in Commodity Price		Decrease in Commodity Price	
	Crude oil	Natural gas	Crude oil	Natural gas
Net income (decrease) increase	$ (41.3)	$ (75.4)	$ 34.0	$ 74.0

As noted above, the sensitivities are hypothetical and based on management's assessment of reasonably possible changes in commodity prices between the balance sheet date and ARC's next reporting date. The results of the sensitivity should not be considered to be predictive of future performance. Changes in the fair value of risk management contracts cannot generally be extrapolated because the relationship of change in certain variables to a change in fair value may not be linear.

Interest Rate Risk

ARC has both fixed and variable interest rates on its debt. Changes in interest rates could result in an increase or decrease in the amount ARC pays to service variable interest rate debt, potentially impacting distributions to unitholders. Changes in interest rates could also result in fair value risk on ARC's fixed rate senior secured notes. Fair value risk of the senior secured notes is mitigated due to the fact that ARC generally does not intend to settle its fixed rate debt prior to maturity.

If interest rates applicable to floating rate debt at March 31, 2010 were to have increased by 50 bps (0.5 per cent) it is estimated that ARC's net income would decrease by $1 million. Management does not expect interest rates to decrease.

Foreign Exchange Risk

North American oil and natural gas prices are based upon U.S. dollar denominated commodity prices. As a result, the price received by Canadian producers is affected by the Canadian/U.S. dollar exchange rate that may fluctuate over time. In addition ARC has U.S. dollar denominated debt and interest obligations of which future cash repayments are directly impacted by the exchange rate in effect on the repayment date. Variations in the Canadian/U.S. dollar exchange rate could also have a positive or negative impact on distributions to unitholders.

The following table demonstrates the effect of exchange rate movements on net income due to changes in the fair value of risk management contracts in place at March 31, 2010 as well as the unrealized gain or loss on revaluation of outstanding US$ denominated debt. The sensitivity is based on a $0.05 Cdn$/US$ increase and $0.05 Cdn$/US$ decrease in the foreign exchange rate.

		Increase in Cdn$/US$ rate		Decrease in Cdn$/US$ rate
Increase gain/decrease loss (increase loss/decrease gain) on risk management contracts	$	1.5	$	(1.5)
(Increase loss/decrease gain) increase gain/decrease loss on foreign exchange		(14.2)		14.6
Net income (decrease) increase	$	(12.7)	$	13.1

Increases and decreases in foreign exchange rates applicable to U.S. dollar denominated payables and receivables would have a nominal impact on ARC's net income for the period ended March 31, 2010.

Risk Management Contracts

ARC uses a variety of derivative instruments to reduce its exposure to fluctuations in commodity prices, foreign exchange rates, interest rates and power prices. ARC considers all of these transactions to be effective economic hedges; however, the majority of ARC'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, 2010 that do not qualify for hedge accounting:

Financial WTI Crude Oil Option Contracts (1)						
Term		Contract	Volume bbl/d	Bought Put US$/bbl	Sold Put US$/bbl	Sold Call US$/bbl
1-Apr-10	31-Dec-10	Collar	4,000	$70.00	-	$90.00
1-Apr-10	31-Dec-10	Collar	2,000	$75.00	-	$95.00
1-Apr-10	31-Dec-10	Collar	5,000	$80.00	-	$90.00
1-Apr-10	31-Dec-10	3-way collar	4,000	$80.00	$60.00	$95.00
1-Jan-11	31-Dec-11	3-way collar	4,000	$80.00	$60.00	$100.00 (2)

(1) Monthly average
(2) Annual average

Financial AECO Natural Gas Swap Contracts (3)				
Term		Contract	Volume GJ/d	Sold Swap Cdn$/GJ
1-Apr-10	31-Dec-10	Swap	80,000	$5.61
1-Jan-11	31-Dec-13	Swap	45,000	$6.06

(3) AECO 7a monthly index

Financial NYMEX Natural Gas Swap Contracts (4)				
Term		Contract	Volume mmbtu/d	Sold Swap US$/mmbtu
1-Apr-10	31-Oct-10	Swap	20,000	$6.00

(4) Last 3 Day Settlement

Financial Basis Swap Contract (5)				
Term		Contract	Volume mmbtu/d	Basis Swap US$/mmbtu

1-Apr-10	31-Oct-10	Basis Swap-L3d	50,000	($1.0430)
1-Nov-10	31-Oct-11	Basis Swap-Ld	15,000	($0.4850)
1-Nov-11	31-Oct-12	Basis Swap-Ld	15,000	($0.4067)

(5) Receive Nymex Last Day (Ld) or Last 3 Day (L3d); pay AECO 7a monthly index

US$ Forward Contracts

Settlement Date	Contract	Notional Volume US$ millions	Swap Cdn$/US$	Swap US$/Cdn$
22-Apr-10	Purchase US$	10.00	$1.0265	$0.9742
22-Apr-10	Purchase US$	10.00	$1.0255	$0.9751
22-Apr-10	Purchase US$	10.00	$1.0128	$0.9874
22-Apr-10	Purchase US$	11.00	$1.0119	$0.9882

Financial Electricity Heat Rate Contracts (6)

Term		Contract	Volume MWh	AESO Power $/MWh	AECO 5a $/GJ	multiplied by	Heat Rate GJ/MWh
1-Apr-10	31-Dec-10	Heat Rate Swap	10	Receive AESO	Pay AECO 5a		x 9.15
1-Jan-11	31-Dec-11	Heat Rate Swap	15	Receive AESO	Pay AECO 5a		x 9.08
1-Jan-12	31-Dec-12	Heat Rate Swap	15	Receive AESO	Pay AECO 5a		x 9.10
1-Jan-13	31-Dec-13	Heat Rate Swap	10	Receive AESO	Pay AECO 5a		x 9.15

(6) Alberta Power Pool (monthly average 24x7); AECO 5a monthly index

Financial Electricity Contracts (7)

Term		Contract	Volume MWh	Bought Swap Cdn$/MWh
1-Apr-10	31-Dec-12	Swap	5	$72.495

(7) Alberta Power Pool (monthly average 24x7); AECO 5a monthly index

Following is a summary of all risk management contracts in place as at March 31, 2010 that qualify for hedge accounting:

Financial Electricity Contracts(8)

Term		Contract	Volume MWh	Bought Swap Cdn$/MWh
1-Apr-10	31-Dec-10	Swap	5	$63.00

(8) Alberta Power Pool (monthly average 24x7), AECO 5a monthly index

At March 31, 2010, the fair value of the contracts that were not designated as accounting hedges was $79.4 million. ARC recorded a gain on risk management contracts of $85 million in the statement of income for the period ended March 31, 2010 ($9.7 million gain in the first quarter of 2009). 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 ARC's financial risk management contracts that have not been designated as effective accounting hedges:

		Three Months Ended March 31, 2010		Three Months Ended March 31, 2009
Fair value, beginning of period	**$**	**(4.3)**	$	3.4
Fair value, end of period [(1)]		**79.4**		(3.2)
Change in fair value of contracts in the period		**83.7**		(6.6)
Realized gain in the period		**1.3**		16.3
Gain on risk management contracts	**$**	**85.0**	$	9.7

(1) Intrinsic value of risk management contracts not designated as effective accounting hedges equals a gain of $80 million at March 31, 2010 ($5.9 million loss at March 31, 2009).

ARC's electricity contracts are intended to manage price risk on electricity consumption. Portions of ARC's financial electricity contracts were designated as effective accounting hedges on their respective contract dates. A realized loss on these electricity contracts of $0.2 million for the three months ended March 31, 2010 (gain of $0.1 million in 2009) has been included in operating costs on the statement of income. The accumulated unrealized fair value loss of $0.5 million on these contracts has been recorded on the Consolidated Balance Sheet at March 31, 2010 with the movement in fair value recorded in OCI, net of tax. The fair value movement for the period ended March 31, 2010 is nominal. As at March 31, 2010 the total unrealized fair value loss is attributed to contracts that will settle over the next twelve months. The following table reconciles the movement in the fair value of ARC's financial risk management contracts that have been designated as effective accounting hedges:

		Three Months Ended March 31, 2010		Three Months Ended March 31, 2009
Fair value, beginning of period	**$**	**(0.5)**	$	3.3
Change in fair value of financial electricity contracts		**-**		(3.0)
Fair value, end of period [(1)]	**$**	**(0.5)**	$	0.3

(1) Intrinsic value of risk management contracts designated as effective accounting hedges equals a loss of $0.5 million at March 31, 2010 ($0.3 million gain at March 31, 2009).

8. EXCHANGEABLE SHARES

(units thousands)	**Three Months Ended March 31, 2010**	Year Ended December 31, 2009
Balance, beginning of period	**871**	1,092
Exchanged for trust units [(1)]	**(5)**	(221)
Balance, end of period	**866**	871
Exchange ratio, end of period	**2.75900**	2.71953
Trust units issuable upon conversion, end of period	**2,389**	2,369

(1) During the first three months of 2010, 4,940 ARL exchangeable shares were converted to trust units at an average exchange ratio of 2.75547, compared to 220,573 exchangeable shares at an average exchange ratio of 2.59547 during the year ended 2009.

Following is a summary of the non-controlling interest for 2010 and 2009:

		Three Months Ended March 31, 2010		Year Ended December 31, 2009
Non-controlling interest, beginning of period	**$**	**36.0**	$	42.4
Reduction of book value for conversion to trust units		**(0.2)**		(8.7)
Current period net income attributable to non-controlling interest		**1.3**		2.3
Non-controlling interest, end of period		**37.1**		36.0
Accumulated earnings attributable to non-controlling interest	**$**	**44.6**	$	43.3

9. UNITHOLDERS' CAPITAL

	Three Months Ended March 31, 2010		Year Ended December 31, 2009	
(units thousands)	**Number of trust units**	**$**	Number of trust units	$
Balance, beginning of period	**236,615**	**2,917.6**	216,435	2,600.7
Issued for cash	**13,000**	**252.3**	15,474	253.0
Issued on conversion of ARL exchangeable shares (Note 8)	**14**	**0.2**	572	8.6
Distribution reinvestment program	**764**	**15.4**	4,134	67.0
Trust unit issue costs, net of tax (1)	**-**	**(10.1)**	-	(11.7)
Balance, end of period	**250,393**	**3,175.4**	236,615	2,917.6

(1) Amount is net of tax of $2.5 million for the period ended March 31, 2010 (net of tax of $2.1 million for the year ended December 31, 2009).

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

(units thousands)	**Three Months Ended March 31, 2010**	Three Months Ended March 31, 2009
Weighted average trust units (1)	249,427	226,477
Trust units issuable on conversion of exchangeable shares (2)	2,389	2,404
Diluted trust units and exchangeable shares	251,816	228,881

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

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.

10. DEFICIT AND ACCUMULATED OTHER COMPREHENSIVE (LOSS) INCOME

		March 31, 2010		December 31, 2009
Accumulated earnings	**$**	**3,086.3**	$	2,946.9
Accumulated distributions		**(3,600.5)**		(3,525.5)
Deficit		**(514.2)**		(578.6)
Accumulated other comprehensive (loss) income		**(0.6)**		(0.6)
Deficit and accumulated other comprehensive (loss) income	**$**	**(514.8)**	$	(579.2)

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

		March 31, 2010		December 31, 2009
Unrealized gains and losses on financial instruments designated as cash flow hedges	**$**	**(0.7)**	$	(0.7)
Net unrealized gains and losses on available-for-sale reclamation funds' investments		**0.1**		0.1
Accumulated other comprehensive (loss) income, end of period	**$**	**(0.6)**	$	(0.6)

11. 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.

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Cash flow from operating activities	**$ 158.7**	$ 124.3
Deduct:		
Cash withheld to fund current period capital expenditures	**(86.7)**	(43.8)
Net reclamation fund withdrawals	**3.0**	1.5
Distributions (1)	**75.0**	82.0
Accumulated distributions, beginning of period	**3,525.5**	3,227.0
Accumulated distributions, end of period	**$ 3,600.5**	$ 3,309.0
Distributions per unit (2)	**$ 0.30**	$ 0.36
Accumulated distributions per unit, beginning of period	**$ 24.98**	$ 23.70
Accumulated distributions per unit, end of period (3)	**$ 25.28**	$ 24.06

(1) Distributions include accrued and non-cash amounts of $16.2 million for the period ended March 31, 2010 ($13.8 million for the period ended March 31, 2009).
(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 ARC in July 1996.

12. 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 (“RTU’s”) and Performance Trust Units (“PTU’s”) and is determined based on the intrinsic value of the Whole Trust Units at each period end. Upon vesting, the plan participant receives a cash payment based on the fair value of the underlying trust units plus accrued distributions.

During the first three months of 2010, cash payments of $15.1 million were made to employees relating to the Whole Unit Plan compared to $7.8 million in 2009.

The following table summarizes the RTU and PTU movement for the three months ended March 31, 2010:

(thousands)	**Number of RTUs**	**Number of PTUs**
Balance, beginning of period	1,052	1,305
Granted	219	134
Vested	(249)	(151)
Forfeited	(15)	(21)
Balance, end of period	1,007	1,267

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

	March 31, 2010	December 31, 2009
Balance, beginning of period	**$ 32.6**	$ 31.9
Change in net liabilities in the period		
General and administrative expense	**(5.5)**	(0.1)
Operating expense	**(0.9)**	0.7
Property, plant and equipment	**(1.0)**	0.1
Balance, end of period (1)	**$ 25.2**	$ 32.6
Current portion of liability (2)	**16.7**	22.4
Accrued long-term incentive compensation	**$ 9.0**	$ 10.9

(1) Includes $0.5 million of recoverable amounts recorded in accounts receivable as at March 31, 2010 ($0.7 million for 2009).
(2) Included in accounts payable and accrued liabilities on the Consolidated Balance Sheet.

13. COMMITMENTS AND CONTINGENCIES

Following is a summary of ARC's contractual obligations and commitments as at March 31, 2010:

	Payments Due by Period				
($ millions)	1 year	2–3 years	4-5 years	Beyond 5 years	Total
Debt repayments (1)	26.4	326.3	91.0	153.5	597.2
Interest payments (2)	19.1	34.5	25.6	24.1	103.3
Reclamation fund contributions (3)	4.9	8.9	7.7	64.2	85.7
Purchase commitments	62.3	34.9	12.6	13.3	123.1
Transportation commitments (4)	6.6	28.5	21.4	5.7	62.2
Operating leases	2.9	14.7	15.0	72.4	105.0
Risk management contract premiums (5)	2.3	1.8	-	-	4.1
Total contractual obligations	124.5	449.6	173.3	333.2	1,080.6

(1) Long-term and short-term debt.
(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 the second quarter of 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, ARC has commitments related to its risk management program (see Note 7). As the premiums are part of the underlying risk management contract, they have been recorded at fair market value at March 31, 2010 on the balance sheet as part of risk management contracts.

ARC enters into commitments for capital expenditures in advance of the expenditures being made. At a given point in time, it is estimated that ARC 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.

ARC 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 ARC's financial position or results of operations and therefore the above table does not include any commitments for outstanding litigation and claims.

Boe conversion ratio for natural gas of 6 mcf: 1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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: those items outlined and described under the heading "Forward-looking information and Statements" at the end of the MD&A section of this news release; and those items relating to conversion of ARC Energy Trust to a dividend paying corporation, future production from Dawson and plans for Phase 2 of the Dawson gas plant and under the heading "Accomplishments/Financial Update on pages two and three of this news release.

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.

ARC Energy Trust is one of Canada's largest conventional oil and gas royalty trusts with a current enterprise value of approximately $6 billion. The Trust expects 2010 oil and gas production to average 70,500 to 72,500 of barrels of oil equivalent per day from six core areas in western Canada. ARC Energy Trust units trade on the TSX under the symbol AET.UN and ARC Resources exchangeable shares trade under the symbol ARX. ARC Energy Trust trades on the TSX under the symbol AET.UN and its exchangeable shares trade under the symbol ARX.

ARC RESOURCES LTD.

John P. Dielwart,
Chief Executive Officer

For further information contact:
Investor Relations, E-mail: ir@arcresources.com

Telephone: (403) 503-8600 Fax: (403) 509-6417 Toll Free 1-888-272-4900

ARC Resources Ltd.
1200, 308 – 4th Avenue S.W., Calgary, AB T2P 0H7
www.arcresources.com