

NEWS RELEASE

November 5, 2009

ARC ENERGY TRUST ANNOUNCES THIRD QUARTER 2009 RESULTS

Calgary, November 5, 2009 (AET.UN and ARX – TSX) ARC Energy Trust (“ARC” or “the Trust”) announces the results for the third quarter ended September 30, 2009.

	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	2009	2008
FINANCIAL				
(Cdn\$ millions, except per unit and per boe amounts)				
Revenue before royalties	239.2	485.7	699.6	1,405.6
Per unit ⁽¹⁾	1.01	2.24	2.98	6.53
Per boe	41.39	82.06	40.12	78.84
Cash flow from operating activities ⁽²⁾	125.6	251.4	354.2	734.8
Per unit ⁽¹⁾	0.53	1.16	1.51	3.41
Per boe	21.73	42.48	20.31	41.22
Net income	68.9	311.7	157.3	450.3
Per unit ⁽³⁾	0.29	1.46	0.68	2.12
Distributions	70.6	171.3	227.6	442.8
Per unit ⁽¹⁾	0.30	0.80	0.98	2.08
Per cent of cash flow from operating activities ⁽²⁾	56	68	64	60
Net debt outstanding ⁽⁴⁾	705.4	773.2	705.4	773.2
OPERATING				
Production				
Crude oil (bbl/d)	26,921	28,509	27,541	28,372
Natural gas (mmcf/d)	193.1	192.0	195.7	197.0
Natural gas liquids (bbl/d)	3,717	3,822	3,720	3,862
Total (boe/d)	62,824	64,325	63,881	65,063
Average prices				
Crude oil (\$/bbl)	67.74	114.2	58.77	107.20
Natural gas (\$/mcf)	3.25	8.68	4.05	8.94
Natural gas liquids (\$/bbl)	38.92	82.87	38.89	77.92
Oil equivalent (\$/boe)	41.31	81.42	40.00	78.44
Operating netback (\$/boe)				
Commodity and other revenue (before hedging) ⁽⁵⁾	41.39	82.06	40.11	78.84
Transportation costs	(0.83)	(0.80)	(0.88)	(0.77)
Royalties	(6.53)	(15.00)	(5.86)	(14.18)
Operating costs	(9.68)	(10.19)	(10.28)	(10.14)
Netback (before hedging)	24.35	56.07	23.09	53.75
TRUST UNITS				
(millions)				
Units outstanding, end of period ⁽⁶⁾	238.1	217.4	238.1	217.4
Weighted average trust units ⁽⁷⁾	237.7	216.6	234.5	215.2
TRUST UNIT TRADING STATISTICS				
(Cdn\$, except volumes) based on intra-day trading				
High	20.20	33.30	20.90	33.95
Low	15.48	22.33	11.73	20.00
Close	20.20	23.10	20.20	23.10
Average daily volume (thousands)	1,038	841	1,088	790

- (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 third quarter of 2009 would be \$124.8 million (\$0.52 per unit) and \$361.9 million (\$1.54 per unit) year-to-date. Distributions as a percentage of Cash Flow would be 57 per cent for the third quarter of 2009 (63 per cent year-to-date).
- (3) Net income per unit is based on net income after non-controlling interest divided by weighted average trust units outstanding (excluding trust units issuable for exchangeable shares).
- (4) Net debt excludes current unrealized amounts pertaining to risk management contracts and the current portion of future income taxes.
- (5) Includes other revenue.
- (6) For the third quarter of 2009, includes 0.9 million (1.1 million in 2008) exchangeable shares exchangeable into 2.679 trust units (2.431 in 2008) each for an aggregate 2.5 million (2.7 million in 2008) trust units.
- (7) Includes trust units issuable for outstanding exchangeable shares at period end.

ACCOMPLISHMENTS / FINANCIAL UPDATE

- Production volumes for the quarter were 62,824 boe per day, a decline of two per cent compared to the second quarter. The Trust continues to expect full year average production between 63,000 and 64,000 boe per day.
- Operating costs decreased to \$9.68 per boe in the quarter compared to \$10.19 per boe in the third quarter of 2008. Total operating costs decreased \$4.3 million, or seven per cent in the third quarter of 2009 as compared to the third quarter of 2008. The decrease in costs is primarily attributed to lower power costs in 2009 as well as cost savings and efficiencies achieved by the operations team. The Trust estimates that full year 2009 operating costs will be approximately \$243 million or approximately \$10.50 per boe based on annual production of between 63,000 and 64,000 boe per day.
- Cash flow from operating activities was \$125.6 million, or \$0.53 per unit, a significant decline from the \$251.4 million (\$1.16 per unit) achieved in the comparable quarter in 2008. This decline was due to a 49 per cent decrease in commodity prices in the third quarter of 2009 compared to the same period in 2008. Crude oil prices strengthened during the third quarter compared to the first half of 2009 as the economy showed some positive signs of recovery. Natural gas prices continued to soften throughout the third quarter reaching a low of \$1.94 per mcf, however they did begin to recover early in the fourth quarter. After payment of distributions the Trust was able to fund 55 per cent of the third quarter capital program with cash flow from operating activities (72 per cent when including the quarterly proceeds from the distributions re-investment program (“DRIP”)) with the remaining portion being funded through proceeds from property dispositions that were completed in the quarter.
- The Trust executed a \$96.2 million capital expenditure program in the third quarter of 2009 that included: drilling 11 oil wells in the Ante Creek, Pembina and Goodlands areas, drilling six natural gas wells in the Dawson area, and spending \$11 million on the new gas plant at Dawson. Of the wells drilled in the third quarter, two natural gas wells and seven oil wells were completed; as well 10 wells were completed that were drilled in previous quarters. Included in the third quarter capital expenditures is a crown land acquisition in Pembina for \$2.4 million where the Trust is planning to drill nine horizontal oil wells into the Cardium zone during the fourth quarter and into 2010. During the quarter, the Trust closed a disposition of non-core assets in southeast Saskatchewan for proceeds of \$33.5 million that were used to fund a portion of the third quarter capital expenditures. Full year capital expenditures are now expected to be approximately \$365 million, an increase of \$15 million over second quarter guidance as the Trust has chosen to increase capital spending in Alberta and British Columbia to take advantage of royalty incentives announced by those provinces.
- At September 30, 2009 the Trust had a net debt balance of \$705.4 million, approximately \$680 million of unused credit available and a net debt to annualized year-to-date cash flow from operating activities of 1.5 times. At this time, the Trust is well positioned to finance the remainder of the 2009 capital program and the projected 2010 capital program.
- ARC plans to convert to a Corporation on January 1, 2011. The Board of Directors has approved the overall strategy and currently the detailed implementation steps are being defined.
- The Trust’s board of directors has approved a \$575 million capital program for 2010 that will encompass considerable growth. The program will include over \$250 million slated for the first of many stages of production growth and continued expansion of the Montney assets in Northeast British Columbia with the remainder focused on ARC base development areas, exploration opportunities and enhanced oil recovery projects. ARC plans to drill 203 gross wells on operated properties and plans to participate in an additional 91 wells on partner operated properties. The Trust plans to finance the 2010 capital program through a combination of cash flow, existing credit facilities, DRIP proceeds and potential minor assets disposition proceeds. Additional details can be found in the November 5, 2009 news release titled “ARC Energy Trust Announces a \$575 million Capital Budget for 2010” and filed on www.sedar.com.

- **Montney Resource Play Development**

Production from the Dawson area was on budget at an average rate of 53.3 mmcf per day throughout the third quarter. The decreased production rates when compared to the second quarter of 2009 were as a result of the planned turnaround of a third party gas plant that shut-in production for the full Dawson field periodically during the month of September.

During the third quarter of 2009, the Trust spent \$41.7 million on development activities in the Dawson area including drilling four horizontal wells and two vertical wells that were drilled and completed during the quarter. ARC tested eight Dawson horizontal wells during the quarter at rates between seven and 11 mmcf per day of natural gas at a flowing pressure of 1,600 to 2,000 pounds per square inch.

At this time, the Trust has 23 wells drilled in the Dawson gas field that are in various stages of completion. In the completed and waiting on tie-in category are 18 wells (11 horizontal and seven vertical), while the remaining five wells (all horizontal) are yet to be completed. In addition to these Dawson wells, ARC has drilled five vertical wells and two horizontal wells in the Sunrise-Sunset area, none of which are tied-in.

In the Montney West lands, ARC drilled a well at Sunset to hold land that was due to expire in the fourth quarter of 2009 allowing ARC to pursue future drilling opportunities on this land. ARC is participating in a small development project on partner operated lands at Sunrise. Current plans call for the drilling of four horizontal wells, construction of pipelines and a gathering system and the expansion of a third party operated gas plant. At quarter end, two horizontal wells had been drilled that will be completed in the fourth quarter. Assuming that the drilling and construction go as planned, production from this area should be approximately 10 mmcf per day net to ARC's 50 per cent working interest by the beginning of 2010.

Due to regulatory delays in receiving final approvals, we now believe the Dawson Phase 1, 60 mmcf per day gas plant start-up will be early in the second quarter of 2010. Year-to-date \$29.8 million has been spent on the gas plant. The British Columbia Oil and Gas Commission ("OGC") has granted conditional approvals, prior to final permit approval, for: site grading (which is completed), pounding pilings (completed pounding 1,350 pilings), mobilizing mechanical contractor's trailers and equipment to site (in progress) and setting major equipment skids (modules are being transported to site). Once final permit approval is received from the OGC all on-site construction will begin.

- **Enhanced Oil Recovery Initiatives**

During the third quarter, the Trust spent \$7.5 million on enhanced oil recovery ("EOR") initiatives and received \$2.8 million in funding from the Alberta Government for the Redwater pilot project for net spending of \$4.7 million during the quarter. Work on the Redwater CO₂ pilot project continues and both the CO₂ injection and oil production facilities are operating. Results to date are encouraging but the Trust anticipates that it will take until the first quarter of 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 CO₂ will be determining factors in the Trust's ability to achieve commercial viability for a full scale EOR scheme at Redwater.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This management's discussion and analysis ("MD&A") is the Trust management's analysis of its financial performance and significant trends or external factors that may affect future performance. It is dated November 4, 2009 and should be read in conjunction with the unaudited Consolidated Financial Statements for the period ended September 30, 2009, the MD&A and the unaudited Consolidated Financial Statements ended June 30, 2009, the MD&A and the unaudited Consolidated Financial Statements ended March 31, 2009 and the audited Consolidated Financial Statements and MD&A as at and for the year ended December 31, 2008 as well as the Trust's Annual Information Form that is filed on SEDAR at www.sedar.com.

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

ARC's Business

ARC Energy Trust ("ARC") or ("the Trust") is an actively managed oil and natural gas entity formed to provide investors with indirect ownership in cash generating energy assets, that currently consist of oil and natural gas assets. The cash flow from operating activities is based on the production and sale of crude oil, natural gas liquids and natural gas.

ARC is one of the top 20 producers of conventional oil and natural gas in western Canada. As at September 30, 2009, ARC held interests in excess of 18,650 wells with approximately 5,700 wells operated by ARC and the remainder principally operated by other major oil and gas companies. ARC's production has averaged between 61,000 and 67,000 boe per day in each quarter for the last three years. The total capitalization of ARC, which trades on the Toronto Stock Exchange, as at September 30, 2009 was \$5.5 billion as shown on Table 22.

ARC's Objective

ARC's objective is to be one of the top performing oil and gas companies in Canada as measured by quality of assets, management expertise and investor returns. The focus is on risk managed value creation. Table 1 shows the Trust's ability to maintain stable production and reserves per unit while distributing a portion of the cash flows back to unitholders. The decrease in 2009 production per unit reflects the impact of issuing 15.5 million trust units in the first quarter that raised \$240 million used to partially fund capital expenditures in the Dawson area. ARC is constructing a 60 mmcf per day capacity gas plant with an expectation that production per unit will increase in 2010 upon startup of this plant.

Table 1

Per Trust Unit	Q3 2009	YTD 2009	Full year 2008	Full year 2007
Normalized production per unit ^{(1) (2)}	0.27	0.28	0.29	0.30
Normalized reserves per unit ^{(1) (3)}	N/A	N/A	1.42	1.35
Distributions per unit	0.30	0.98	\$2.67	\$2.40

⁽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) at period end divided by period end trust units outstanding including trust units issuable for exchangeable shares.

Currently the Trust distributes \$0.10 per unit per month. The remainder of the cash flow is used to fund reclamation costs, and a portion of capital expenditures and land acquisitions. Since the Trust's inception in July 1996 to September 30, 2009, the Trust has distributed \$3.5 billion or \$24.68 per unit.

ARC's business plan has resulted in significant operational success as seen in Table 2 where the Trust's trailing five year annualized return per unit was 14.3 per cent. However, commodity prices and the current economic downturn are significant factors impacting the profitability of ARC and capital appreciation of our trust units in the market place. The impact of these external factors has led to a negative return for the trailing one year despite the successful execution of ARC's business plan and operational successes.

Table 2

Total Returns ⁽¹⁾ (\$ per unit except for per cent)	Trailing One Year	Trailing Three Year	Trailing Five Year
Distributions per unit	\$ 1.57	\$ 6.65	\$ 10.89
Capital appreciation per unit	\$ (2.90)	\$ (7.01)	\$ 3.35
Total return per unit	(4.3)%	0.6%	95.3%
Annualized total return per unit	(4.3)%	0.2%	14.3%
S&P/TSX Capped Energy Trust Index	(12.0)%	(2.4)%	9.4%

⁽¹⁾ Calculated as at September 30, 2009.

2009 Third Quarter Financial and Operational Results

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

2009 Guidance and Financial Highlights

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

Table 3

	Revised 2009 Guidance	2009 Actual YTD	% Change
Production (boe/d)	63,000-64,000	63,881	-
Expenses (\$/boe):			
Operating costs ⁽¹⁾	10.50	10.28	(2)
Transportation ⁽²⁾	0.90	0.88	(2)
G&A expenses (cash & non-cash) ⁽³⁾	2.10	2.20	5
Interest	1.30	1.14	(12)
Capital expenditures (\$ millions) ⁽⁴⁾	365	242.3	-
Annual weighted average trust units and trust units issuable (millions)	238	235	-

⁽¹⁾ The Trust has revised full year 2009 operating costs from the original estimate of \$10.70 per boe to be approximately \$10.50 per boe or \$243 million based on annual production of between 63,000 and 64,000 boe per day. This decrease is to reflect lower electricity costs recorded throughout the third quarter and overall costs savings being achieved by the operations team.

⁽²⁾ Full year transportation expense has been revised downward to \$0.90 per boe from \$1.00 per boe based on reduced estimates for oil trucking requirements throughout the third and fourth quarters.

⁽³⁾ G&A guidance amount of \$2.10 per boe includes \$1.75 per boe for cash G&A costs, \$0.55 per boe for cash Whole Unit Plan costs and a recovery of \$0.20 per boe for non-cash portion of the Whole Unit Plan.

⁽⁴⁾ Full year capital expenditures are now expected to be approximately \$365 million, an increase of \$15 million over second quarter guidance as the Trust has chosen to increase capital spending in Alberta and British Columbia to take advantage of royalty incentives announced by those provinces.

The 2009 Guidance provides unitholders with information on Management's expectations for results of operations, excluding any acquisitions or dispositions for 2009. Readers are cautioned that the 2009 Guidance may not be appropriate for other purposes.

Table 4 is a review of the financial highlights and operating results for the third quarter and the first nine months of 2009.

Table 4

(Cdn \$ millions, except per unit and volume data)	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	2009	2008	% Change
Cash flow from operating activities	125.6	251.4	(50)	354.2	734.8	(52)
Cash flow from operating activities per unit ⁽¹⁾	0.53	1.16	(54)	1.51	3.41	(56)
Net income	68.9	311.7	(78)	157.3	450.3	(65)
Net income per unit ⁽²⁾	0.29	1.46	(80)	0.68	2.12	(68)
Distributions per unit ⁽³⁾	0.30	0.80	(63)	0.98	2.08	(53)
Distributions as a per cent of cash flow from operating activities	56	68	(18)	64	60	7
Average daily production (boe/d) ⁽⁴⁾	62,824	64,325	(2)	63,881	65,063	(2)

- (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.

Net Income

Net income in the third quarter of 2009 was \$68.9 million (\$0.29 per unit), a decrease of \$242.8 million from \$311.7 million (\$1.46 per unit) in the third quarter of 2008. The net income recorded in the third quarter of 2008 reflected certain non-cash gains, as detailed below, resulting in record net income when combined with the strong commodity prices received for the quarter. Net income for the third quarter of 2009 reflects the decreased commodity price environment in the current year and includes certain non-cash items that also served to increase the net income during the period.

In the third quarter of 2008, the Trust recorded a \$187.5 million unrealized non-cash gain on risk management contracts (\$140.6 million net of future income taxes). As well, the Trust recorded a \$15.5 million non-cash foreign exchange loss on its U.S. denominated debt as a result of the movement in the Canadian dollar relative to the U.S. dollar (\$13.6 million net of future income taxes).

In the third quarter of 2009, the Trust recorded a \$34.9 million non-cash foreign exchange gain on U.S. denominated debt (\$30.5 million net of future income taxes) and a \$0.7 million unrealized non-cash loss on risk management contracts (\$0.5 million net of future income taxes).

A measure of sustainability is the comparison of net income to distributions. Net income incorporates all costs including depletion expense and other non-cash expenses whereas cash flow from operating activities measures the cash generated in a given period before the cost of acquiring or replacing the associated reserves produced. Therefore, net income may be more representative of the profitability of the entity and thus a relevant measure against which to measure distributions to illustrate sustainability. As net income is sensitive to fluctuations in commodity prices and the impact of risk management contracts, currency fluctuations and other non-cash items, it is expected that there will be deviations between annual net income and distributions. Table 5 illustrates the comparison of distributions to net income as a measure of long-term sustainability. Distributions have been reduced from \$0.24 per unit per month in October 2008 to the current rate of \$0.10 per unit per month.

Table 5

Net income and Distributions (\$ millions except per cent)	Third quarter 2009	YTD 2009	Full year 2008	Full year 2007
Net income	68.9	157.3	533.0	495.3
Distributions	70.6	227.6	570.0	498.0
Excess (Shortfall)	(1.7)	(70.3)	(37.0)	(2.7)
Excess (Shortfall) as per cent of net income	(2%)	(45%)	(7%)	(1%)
Cash flow from operating activities	125.6	354.2	944.4	704.9
Distributions as a per cent of cash flow from operating activities	56%	64%	60%	71%
Average distribution per unit per month	\$0.10	\$0.11	\$0.22	\$0.20

Cash Flow from Operating Activities

Cash flow from operating activities decreased by 50 per cent in the third quarter of 2009 to \$125.6 million from \$251.4 million in the third quarter of 2008. Decreases in crown royalties and cash losses on risk management contracts were more than offset by the 49 per cent (\$40.11 per boe) decrease in commodity prices relative to the third quarter of 2008 as well as a two per cent decrease in volumes during the period. The decrease in third quarter 2009 cash flow from operating activities compared with the third quarter of 2008 is detailed in Table 6.

Table 6

	(\$ millions)	(\$ per trust unit)	(% Change)
Q3 2008 Cash flow from Operating Activities	251.4	1.16	-
Volume variance	(11.3)	(0.05)	(4.5)
Price variance	(235.2)	(1.10)	(93.6)
Cash (losses) and gains on risk management contracts	41.0	0.19	16.3
Royalties	51.1	0.24	20.3
Expenses:			
Transportation	-	-	-
Operating ⁽¹⁾	5.5	0.03	2.2
Cash G&A	(7.3)	(0.03)	(2.9)
Interest	1.4	0.01	0.6
Taxes	(0.2)	-	(0.1)
Realized foreign exchange loss	0.8	-	0.3
Weighted average trust units	-	(0.05)	-
Non-cash and other items ⁽²⁾	28.4	0.13	11.3
Q3 2009 Cash flow from Operating Activities	125.6	0.53	-

⁽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.

Year-to-date cash flow from operating activities decreased by 52 per cent in 2009 to \$354.2 million from \$734.8 million in the comparable nine month period of 2008. The 49 per cent decrease in year-to-date commodity prices relative to the same period of 2008 more than offset decreases in crown royalties and cash losses on risk management contracts. The decrease in year-to-date 2009 cash flow from operating activities compared with the first nine months of 2008 is detailed in Table 6a.

Table 6a

	(\$ millions)	(\$ per trust unit)	(% Change)
YTD 2008 Cash flow from Operating Activities	734.8	3.41	-
Volume variance	(30.6)	(0.14)	(4.2)
Price variance	(675.4)	(3.12)	(91.9)
Cash (losses) and gains on risk management contracts	129.6	0.60	17.6
Royalties	150.6	0.70	20.5
Expenses:			
Transportation	(1.5)	(0.01)	(0.2)
Operating ⁽¹⁾	1.0	-	0.1
Cash G&A	0.1	-	-
Interest	5.1	0.02	0.7
Taxes	(0.2)	-	-
Realized foreign exchange loss	1.3	0.01	0.2
Weighted average trust units	-	(0.14)	-
Non-cash and other items ⁽²⁾	39.4	0.18	5.4
YTD 2009 Cash flow from Operating Activities	354.2	1.51	-

⁽¹⁾ Excludes non-cash portion of Whole Unit Plan expense recorded in operating costs.

⁽²⁾ Includes the changes in non-cash working capital and expenditures on site restoration and reclamation.

2009 Cash Flow from Operating Activities Sensitivity

Table 7 illustrates sensitivities to pre-hedged operating income items with operational changes and changes to the business environment and the resulting impact on cash flows from operating activities in total and per trust unit:

Table 7

Business Environment	Assumption	Impact on Annual Cash flow from operating activities ⁽²⁾		
		Change		\$/Unit
Oil price (US\$WTI/bbl) ⁽¹⁾	\$ 60.00	\$ 1.00	\$	0.04
Natural gas price (Cdn\$AECO/mcf) ⁽¹⁾	\$ 4.35	\$ 0.10	\$	0.02
Cdn\$/US\$ exchange rate ⁽³⁾	1.15	\$ 0.01	\$	0.03
Interest rate on debt	% 3.90	% 1.0	\$	0.02
Operational				
Liquids production volume (bbl/d)	31,500	% 1.0	\$	0.02
Gas production volumes (mmcf/d)	189.0	% 1.0	\$	0.01
Operating expenses per boe	\$ 10.50	% 1.0	\$	0.01
Cash G&A and LTIP expenses per boe	\$ 2.30	% 10.0	\$	0.02

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

⁽²⁾ Assumes constant working capital.

⁽³⁾ Includes impact of foreign exchange on crude oil prices which 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.

Production

Production volumes averaged 62,824 boe per day in the third quarter of 2009 compared to 64,325 boe per day in the same period of 2008 as detailed in Table 8. The decrease in third quarter 2009 production is a result of turnarounds at the Dawson property as well as natural production declines as a result of the decreased capital spending in 2009.

Table 8

Production	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	2009	2008	% Change
Light & medium crude oil (bbl/d)	25,930	27,211	(5)	26,561	27,073	(2)
Heavy oil (bbl/d)	991	1,298	(24)	981	1,299	(24)
Natural gas (mmcf/d)	193.1	192.0	1	195.7	197.0	(1)
NGL (bbl/d)	3,717	3,822	(3)	3,720	3,862	(4)
Total production (boe/d) ⁽¹⁾	62,824	64,325	(2)	63,881	65,063	(2)
% Natural gas production	51	50		51	50	
% Crude oil and liquids production	49	50		49	50	

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

Light and medium crude oil production decreased to 25,930 boe per day compared to 27,211 boe per day in 2008, while heavy oil production declined by 307 boe per day. When compared to the second quarter of 2009, the total crude oil production is relatively flat, as a result of a successful drilling program at Goodlands, Pembina and Ante Creek that helped to offset natural decline. Natural gas production was 193.1 mmcf per day in the third quarter of 2009, an increase of one per cent from the 192 mmcf per day produced in the third quarter of 2008 but down 3.5 per cent from the second quarter of 2009. The decrease in production over the second quarter of 2009 is due primarily to the planned turnaround completed at a third party facility that shut-in production at Dawson periodically throughout the month of September as well as other turnarounds in the Northern Alberta district that occurred during the month of July.

The Trust's objective is to maintain annual production through the drilling of wells and other development activities to the full extent possible while giving considerations to capital spending constraints. In fulfilling this objective, there may be fluctuations in production depending on the timing of new wells coming on-stream. During the third quarter of 2009, the Trust drilled 17 gross wells (16 net wells) on operated properties; 11 gross oil wells, and six gross natural gas wells with a 100 per cent success rate. Of the wells drilled during the third quarter, two gas wells and seven oil wells were completed. Five of the oil wells completed were brought on production during the quarter.

The Trust expects that 2009 full year production will average approximately 63,000 to 64,000 boe per day and that a total of 146 gross wells (120 net) will be drilled by ARC on operated properties with participation in an additional 54 gross wells to be drilled on the Trust's non-operated properties. The Trust estimates that the revised 2009 drilling program will add sufficient production from new wells to offset the majority of production declines on existing properties, however, overall production is expected to decrease by 1,000 to 2,000 boe per day relative to 2008

production levels. The planned capital expenditures for 2009 have been increased to approximately \$365 million to take advantage of royalty incentives announced by the provinces of Alberta and British Columbia.

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

Table 9

Production Core Area ⁽¹⁾	Three Months Ended September 30, 2009				Three Months Ended September 30, 2008			
	Total (boe/d)	Oil (bbl/d)	Gas (mmcf/d)	NGL (bbl/d)	Total (boe/d)	Oil (bbl/d)	Gas (mmcf/d)	NGL (bbl/d)
Central AB	7,218	1,370	28.4	1,106	7,428	1,380	29.0	1,218
N.E. BC & N.W. AB	13,517	703	72.8	673	12,241	749	65.6	556
Northern AB	8,551	3,891	23.1	806	9,464	4,363	24.6	997
Pembina & Redwater	13,609	9,298	19.9	992	13,972	9,866	19.1	921
S.E. AB & S.W. Sask.	8,951	1,053	47.3	12	9,629	977	51.9	8
S.E. Sask. & MB	10,978	10,605	1.5	127	11,591	11,175	1.8	122
Total	62,824	26,920	193.0	3,716	64,235	28,510	192.0	3,822

⁽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.

Table 9a summarizes the Trust's production by core area for the nine months of 2009:

Table 9a

Production Core Area ⁽¹⁾	Nine Months Ended September 30, 2009				Nine Months Ended September 30, 2008			
	Total (boe/d)	Oil (bbl/d)	Gas (mmcf/d)	NGL (bbl/d)	Total (boe/d)	Oil (bbl/d)	Gas (mmcf/d)	NGL (bbl/d)
Central AB	7,089	1,281	28.2	1,108	7,549	1,405	29.5	1,228
N.E. BC & N.W. AB	13,868	722	74.9	673	12,492	811	66.4	601
Northern AB	9,005	4,072	24.6	837	10,058	4,662	26.7	952
Pembina & Redwater	13,540	9,374	19.2	962	13,599	9,405	19.7	911
S.E. AB & S.W. Sask.	8,923	1,016	47.4	13	9,826	991	52.9	12
S.E. Sask. & MB	11,456	11,076	1.5	127	11,539	11,098	1.8	158
Total	63,881	27,541	195.8	3,720	65,063	28,372	197.0	3,862

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

Revenue

Revenue decreased to \$239.2 million in the third quarter of 2009, \$246.5 million lower than 2008 revenues of \$485.7 million. The decrease in realized oil prices accounted for a \$121.9 million decrease in revenues with only \$9.9 million of the decrease attributable to lower oil volumes. Natural gas revenue decreased by \$95.6 million which was almost entirely attributable to decreased realized prices as volumes were flat over the same period in 2008.

A breakdown of revenue is outlined in Table 10:

Table 10

Revenue (\$ millions)	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	2009	2008	% Change
Oil revenue	167.7	299.5	(44)	441.8	833.3	(47)
Natural gas revenue	57.7	153.3	(62)	216.3	482.6	(55)
NGL revenue	13.3	29.1	(54)	39.5	82.4	(52)
Total commodity revenue	238.7	481.9	(50)	697.6	1,398.3	(50)
Other revenue	0.5	3.8	(87)	2.0	7.3	(73)
Total revenue	239.2	485.7	(51)	699.6	1,405.6	(50)

Commodity Prices Prior to Hedging

Table 11

	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	2009	2008	% Change
Average Benchmark Prices						
AECO gas (\$/mcf) ⁽¹⁾	3.03	9.27	(67)	4.10	8.58	(52)
WTI oil (US\$/bbl) ⁽²⁾	68.29	118.18	(42)	57.13	113.39	(50)
Cdn\$ / US\$ exchange rate	1.10	1.04	6	1.16	1.02	14
WTI oil (Cdn\$/bbl)	74.90	121.77	(38)	66.08	114.99	(43)
ARC Realized Prices Prior to Hedging						
Oil (\$/bbl)	67.74	114.20	(41)	58.77	107.20	(45)
Natural gas (\$/mcf)	3.25	8.68	(63)	4.05	8.94	(55)
NGL (\$/bbl)	38.92	82.87	(53)	38.89	77.91	(50)
Total commodity revenue before hedging (\$/boe)	41.31	81.42	(49)	40.00	78.44	(49)
Other revenue (\$/boe)	0.08	0.64	(88)	0.11	0.40	(73)
Total revenue before hedging (\$/boe)	41.39	82.06	(50)	40.11	78.84	(49)

⁽¹⁾ Represents the AECO monthly posting.

⁽²⁾ WTI represents posting price of West Texas Intermediate oil.

Oil prices continued to recover in the third quarter of 2009 with US\$WTI prices averaging \$68.29 as compared to \$51.46 for the first half of 2009. Despite this recovery, prices in the third quarter of 2009 were down 42 per cent compared to the same period of 2008 as detailed in Table 11. This large decrease was partially offset by the weakening of the Canadian dollar compared to the U.S. dollar; however, some widening of the price differentials further eroded the Trust's realized oil price. The Trust's oil production consists predominantly of light and medium crude oil while heavy oil accounts for less than five per cent of the Trust's crude oil production. The realized price for the Trust's oil, before hedging, was \$67.74 per boe, a 41 per cent reduction over the third quarter 2008 realized price of \$114.20 per boe.

Natural gas prices softened throughout the third quarter of 2009. Alberta AECO Hub natural gas prices, which are commonly used as an industry reference, averaged \$3.03 per mcf in the third quarter of 2009 compared to \$9.27 per mcf in the same period of 2008. ARC's realized gas price, before hedging, decreased by 63 per cent to \$3.25 per mcf compared to \$8.68 per mcf in the third quarter of 2008. ARC's realized gas price is based on prices received at the various markets in which the Trust sells its natural gas. ARC's natural gas sales portfolio consists of gas sales priced at the AECO monthly index, the AECO daily spot market, eastern and mid-west United States markets and a portion to aggregators. Natural gas prices have started to recover in the fourth quarter of 2009 with posted prices in the month of October registering over \$5 per mcf. In addition, the forward curve for natural gas prices has strengthened to reflect 2010 prices of over \$6 per mcf. Management is pursuing strategic initiatives to capitalize on strong forward prices, where possible in order to protect the economics of the 2010 capital program.

Prior to hedging activities, ARC's total realized commodity price was \$41.31 per boe in the third quarter of 2009, a 49 per cent decrease from the \$81.42 per boe received prior to hedging in the third quarter of 2008.

Risk Management and Hedging Activities

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

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

Lower natural gas prices in the third quarter of 2009 resulted in realized cash gains of \$10.4 million on natural gas risk management contracts as the Trust's contracted prices were higher than market prices during the quarter. Realized cash losses of \$3.6 million were recorded on the Trust's crude oil risk management contracts as a result of premiums paid during the third quarter of 2009 and small losses recorded on the Trust's fixed price swap contracts where the market oil price rose above the contracted price.

ARC's third quarter 2009 results include an unrealized total mark-to-market loss of \$0.7 million with a net unrealized mark-to-market loss position of \$4.8 million as at September 30, 2009. The net loss position is mostly attributed to losses on the Trust's power and natural gas contracts and offset by gains on the Trust's crude oil contracts. The mark-to-market values represent the market price to buy-out the Trust's contracts as of September 30, 2009 and may differ from what will eventually be realized.

In the third quarter of 2008, the Trust recorded a significant unrealized gain on risk management contracts as commodity prices, and in particular oil prices, declined significantly at the end of the quarter when compared to the previous reporting period. The realized cash losses in the third quarter of 2008 were mostly attributable to crude oil contracts where the market prices were in excess of ARC's contracted price.

Table 12 summarizes the total gain (loss) on risk management contracts for the third quarter of 2009 as compared to the same period in 2008:

Table 12

Risk Management Contracts (\$ millions)	Crude Oil & Liquids	Natural Gas	Foreign Currency	Power⁽³⁾	Interest	Q3 2009 Total	Q3 2008 Total
Realized cash (loss) gain on contracts ⁽¹⁾	(3.6)	10.4	0.2	(0.3)	-	6.7	(34.3)
Unrealized (loss) gain on contracts ⁽²⁾	12.1	(11.4)	-	(1.4)	-	(0.7)	187.5
Total (loss) gain on risk management contracts	8.5	(1.0)	0.2	(1.7)	-	6.0	153.2

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

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

⁽³⁾ Amounts presented in Table 12 exclude a \$0.3 million realized loss and an unrealized loss of \$0.4 million for the Trust's power contracts that have been designated as effective hedges for accounting purposes. Realized gains and losses on these contracts are recorded in operating costs and unrealized gains and losses are recorded in the Consolidated Statement of Comprehensive Income and Accumulated Other Comprehensive Income.

Table 12a summarizes the total gain (loss) on risk management contracts for the first nine months of 2009 as compared to the same period in 2008:

Table 12a

Risk Management Contracts (\$ millions)	Crude Oil & Liquids	Natural Gas	Foreign Currency	Power⁽³⁾	Interest	YTD 2009 Total	YTD 2008 Total
Realized cash (loss) gain on contracts ⁽¹⁾	(10.5)	26.6	1.0	(0.8)	4.8	21.1	(108.5)
Unrealized (loss) gain on contracts ⁽²⁾	7.2	(4.9)	-	(4.8)	(5.4)	(7.9)	26.0
Total (loss) gain on risk management contracts	(3.3)	21.7	1.0	(5.6)	(0.6)	13.2	(82.5)

⁽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 12a exclude a \$1.1 million realized loss and an unrealized loss of \$3.6 million for the Trust's power contracts that have been designated as effective hedges for accounting purposes. Realized gains and losses on these contracts are recorded in operating costs and unrealized gains and losses are recorded in the Consolidated Statement of Comprehensive Income and Accumulated Other Comprehensive Income.

The Trust currently limits the amount of forecast production that can be hedged to a maximum 50 per cent with the remaining 50 per cent of production being sold at market prices. The following table is an indicative summary of the Trust's positions for crude oil and natural gas as at September 30, 2009.

Table 13

Hedge Positions									
As at September 30, 2009 ⁽¹⁾⁽²⁾									
Q4 2009			Q1 2010		Q2 2010⁽³⁾		Q3-Q4 2010		
Crude Oil	US\$/bbl	bbl/day	US\$/bbl	bbl/day	US\$/bbl	bbl/day	US\$/bbl	bbl/day	
Sold Call	83.02	7,000	96.50	5,000	96.50	4,000	96.50	4,000	
Bought Put	67.61	9,500	75.05	5,000	75.05	4,000	75.05	4,000	
Sold Put	42.89	2,500	-	-	-	-	-	-	
Natural Gas	Cdn\$/GJ	GJ/day	Cdn\$/GJ	GJ/day	Cdn\$/GJ	GJ/day	Cdn\$/GJ	GJ/day	
Sold Call	5.52	93,370	6.80	5,000	6.80	5,000	6.80	5,000	
Bought Put	4.84	93,370	6.80	5,000	6.80	5,000	6.80	5,000	
Sold Put	4.50	20,000	-	-	-	-	-	-	

- (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.
- (2) In addition to positions shown here, ARC has entered into additional basis positions until October 2012, an energy equivalent swap until December 31, 2009. Please refer to note 8 in the Notes to the Consolidated Financial Statements for full details of the Trust's risk management positions as of September 30, 2009.
- (3) The natural gas contract listed for 2010 is a fixed price swap starting in 2010 and ending in December 2013. During the quarter, the Trust took advantage of favorable forward curve pricing for natural gas and entered into a long-term contract for a small portion of future forecast production.

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

- If the market price is below \$42.89, ARC will receive \$67.61 less the difference between \$42.89 and the market price on 2,500 bbl per day. For example if the market price is \$42.85, the Trust will receive \$67.57 on 2,500 bbl per day.
- If the market price is between \$42.89 and \$67.61, ARC will receive \$67.61 on 9,500 bbl per day.
- If the market price is between \$67.61 and \$83.02, ARC will receive the market price on 9,500 per day.
- If the market price exceeds \$83.02, ARC will receive \$83.02 on 7,000 per day.

Operating Netbacks

The Trust's operating netback, before realized hedging gains and losses, decreased 57 per cent to \$24.35 per boe in the third quarter of 2009 compared to \$56.07 per boe in the same period of 2008. The decrease in netbacks is due most significantly to the reduced commodity prices and the corresponding reduction in royalties in the period.

The Trust's third quarter 2009 netback, after realized hedging gains and losses, was \$25.47 per boe, a 49 per cent decrease from the same period in 2008. The 2009 netback includes net gains recorded on the Trust's crude oil and natural gas risk management contracts during the quarter of \$1.12 per boe compared to a net loss of \$5.79 per boe recorded for the same period in 2008.

The components of operating netbacks are summarized in Table 14 and 14a:

Table 14

Netbacks	Crude Oil	Heavy Oil	Gas	NGL	Q3 2009	Q3 2008
(\$ per boe)	(\$/bbl)	(\$/bbl)	(\$/mcf)	(\$/bbl)	Total	Total
					(\$/boe)	(\$/boe)
Weighted average sales price	67.98	61.54	3.25	38.92	41.31	81.42
Other revenue	-	-	-	-	0.08	0.64
Total revenue	67.98	61.54	3.25	38.92	41.39	82.06
Royalties	(10.71)	(7.52)	(0.40)	(12.65)	(6.53)	(15.00)
Transportation	(0.14)	(0.64)	(0.25)	-	(0.83)	(0.80)
Operating costs ⁽¹⁾	(13.58)	(9.79)	(1.18)	(9.37)	(9.68)	(10.19)
Netback prior to hedging	43.55	43.59	1.42	16.90	24.35	56.07
Realized gain (loss) on risk management contracts ⁽²⁾	(1.63)	-	0.58	-	1.12	(5.79)
Netback after hedging	41.92	43.59	2.00	16.90	25.47	50.28

Table 14a

Netbacks (\$ per boe)	Crude Oil (\$/bbl)	Heavy Oil (\$/bbl)	Gas (\$/mcf)	NGL (\$/bbl)	YTD 2009 Total (\$/boe)	YTD 2008 Total (\$/boe)
Weighted average sales price	58.99	52.59	4.05	38.89	40.00	78.44
Other revenue	-	-	-	-	0.11	0.40
Total revenue	58.99	52.59	4.05	38.89	40.11	78.84
Royalties	(8.73)	(4.73)	(0.47)	(12.33)	(5.86)	(14.18)
Transportation	(0.15)	(1.12)	(0.26)	-	(0.88)	(0.77)
Operating costs ⁽¹⁾	(13.11)	(12.52)	(1.34)	(8.45)	(10.28)	(10.14)
Netback prior to hedging	37.00	34.22	1.98	18.11	23.09	53.75
Realized gain (loss) on risk management contracts ⁽²⁾	(1.56)	-	0.50	-	0.88	(6.08)
Netback after hedging	35.44	34.22	2.48	18.11	23.97	47.67

⁽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 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 decreased to 16.1 per cent (\$6.53 per boe) in the third quarter of 2009 compared to 18.5 per cent (\$15.00 per boe) in 2008. Royalties for the first nine months of 2009 decreased to 14.9 per cent (\$5.86 per boe) as compared to 18.2 per cent (\$14.18) for the same period of 2008.

The Alberta Government's 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 2009 royalty rate is in line with Management's expectations due to the low natural gas price environment. The recovery of crude oil prices in the third quarter of 2009 has resulted in higher oil crown royalty payments as compared to the first half of 2009.

Following the implementation of the ARF, the Alberta Government introduced certain transitional rates and incentive programs to provide royalty relief to producers and in turn 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 and is currently estimated to generate a maximum \$15 million credit over the two year period based on forward looking prices at this time. The Trust 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 third quarter of 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 this 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 20 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 \$9.68 per boe compared to \$10.19 per boe in the third quarter of 2008. Total operating costs decreased \$4.3 million, or seven per cent in the third quarter of 2009 as compared to the third quarter of 2008. The decrease in costs is primarily attributed to lower power costs in 2009 as well as some cost savings and efficiencies achieved by the operations team.

The Trust has revised full year 2009 operating costs from the original estimate of \$10.70 per boe to be approximately \$10.50 per boe or \$243 million based on annual production of between 63,000 and 64,000 boe per day. This

decrease is to reflect lower electricity costs recorded throughout the third quarter and overall costs savings being achieved by the operations team.

General and Administrative (“G&A”) Expenses and Trust Unit Incentive Compensation

G&A, prior to long-term incentive payments under the Whole Unit Plan and net of overhead recoveries on operated properties, increased 13 per cent to \$10.2 million in the third quarter of 2009 from \$9 million in 2008. The modest increase in G&A expenses was due to a decrease in operating recoveries of \$1 million resulting from lower levels of capital spending during the quarter.

A cash payment was made under the Whole Unit Plan in September 2009 for \$8.6 million, of which \$6.1 million was recorded in G&A with the remainder of \$2.5 million being recorded to operating costs and capital projects. There was no cash payment made in the third quarter of 2008, as the corresponding cash payment of \$9.7 million was made in the fourth quarter of 2008 of which \$6.9 million was recorded in G&A. The next cash payment under the Whole Unit Plan is scheduled to occur in March 2010.

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

Table 15

	Three Months Ended September 30			Nine Months Ended September 30		
G&A and Trust Unit Incentive Compensation Expense						
(\$ millions except per boe)	2009	2008	% Change	2009	2008	% Change
G&A expenses	13.5	13.3	2	42.1	40.3	4
Operating recoveries	(3.3)	(4.3)	(23)	(11.3)	(12.2)	(7)
Cash G&A expenses before Whole Unit Plan	10.2	9.0	13	30.8	28.1	10
Cash Expense – Whole Unit Plan	6.1	-	-	11.7	14.4	(19)
Cash G&A expenses including Whole Unit Plan	16.3	9.0	81	42.5	42.5	-
Accrued compensation - Whole Unit Plan	(0.4)	(5.5)	(93)	(4.0)	4.7	(185)
Total G&A and trust unit incentive compensation expense	15.9	3.5	354	38.5	47.2	(18)
Total G&A and trust unit incentive compensation expense per boe	2.75	0.59	366	2.20	2.65	(17)

A non-cash Whole Unit Plan recovery (“non-cash compensation recovery”) of \$0.4 million (\$0.07 per boe) was recorded in the third quarter of 2009 compared to a recovery of \$5.5 million (\$0.93 per boe) in 2008. The recovery in 2009 relates to the estimated costs of the plan to September 30, 2009, offset by a reversal of the accrual for the cash payment made in the third quarter. The 2008 non-cash amount relates to a decrease in the liability of the units outstanding due to the decrease in the trust unit price relative to the closing price of the trust units at June 30, 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 performance of the Trust compared to its peers and indicated by the performance multiplier. The performance multiplier is based on the percentile rank of the Trust’s total unitholder return compared to its peers. Total return is calculated as the sum of the change in the market price of the trust units in the period plus the amount of distributions in the period. The performance multiplier ranges from zero, if ARC’s performance ranks in the bottom quartile, to two for top quartile performance.

Table 16 shows the changes to the Whole Unit Plan during the first nine months of 2009 along with the estimated value upon vesting of the plan as at September 30, 2009:

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	756	959	1,715
Granted in the period	697	634	1,331
Vested in the period	(355)	(262)	(617)
Forfeited in the period	(43)	(24)	(67)
Balance, end of period ⁽¹⁾	1,055	1,307	2,362
Estimated distributions to vesting date ⁽²⁾	184	317	501
Estimated units upon vesting after distributions	1,239	1,624	2,863
Performance multiplier ⁽³⁾	-	1.3	-
Estimated total units upon vesting	1,239	2,062	3,301
Trust unit price at September 30, 2009	20.20	20.20	20.20
Estimated total value upon vesting (\$ millions)	25.0	41.7	66.7

(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 1.3 at September 30, 2009 based on an average calculation of all outstanding grants. The performance multiplier is assessed each period end based on actual results of the Trust relative to its peers except during the first year of each grant where a performance multiplier of 1.0 is used.

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

Table 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 as at September 30, 2009:

Table 17

Value of Whole Unit Plan as at September 30, 2009 (units thousands and \$ millions except per unit)	Performance multiplier		
	-	1.0	2.0
Estimated trust units to vest			
RTUs	1,239	1,239	1,239
PTUs	-	1,624	3,248
Total units ⁽¹⁾	1,239	2,863	4,487
Trust unit price ⁽²⁾	20.20	20.20	20.20
Trust unit distributions per month ⁽²⁾	0.10	0.10	0.10
Value of Whole Unit Plan upon vesting ⁽³⁾	25.0	57.8	90.6
2010	11.1	20.0	28.8
2011	8.4	17.0	25.7
2012	5.5	20.8	36.1

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

(2) Values will fluctuate over the vesting period based on the volatility of the underlying trust unit price and distribution levels. Assumes a future trust unit price of \$20.20 and \$0.10 per trust unit distributions based on the unit price and distribution levels in place at September 30, 2009.

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

Due to the variability in the future payments under the plan, the Trust estimates that between \$25 million and \$90.6 million will be paid out from 2010 through 2012 based on the current trust unit price, distribution levels and the Trust's market performance relative to its peers.

Interest and financing charges

Interest and financing charges decreased to \$6.4 million in the third quarter of 2009 from \$7.8 million in 2008 due to a decrease in short-term interest rates as well as a lower amount of debt outstanding. As at September 30, 2009, the Trust had \$637.1 million of long-term debt outstanding, of which \$355 million was fixed at a weighted average rate of six per cent and \$282.1 million, including the working capital facility, was floating at current market rates plus a credit spread of 60 basis points. Sixty per cent (US\$355.1 million) of the Trust's debt outstanding is denominated in U.S. dollars. The Trust's credit facility is a three year facility maturing in April 2011. Management's current expectation is that the current 60 point credit spread would increase upon renewal by 150 to 250 basis points.

Foreign Exchange Gains and Losses

The Trust recorded a gain of \$34.9 million in the third quarter of 2009 on foreign exchange transactions compared to a loss of \$16.3 million in 2008. These amounts include both realized and unrealized foreign exchange gains and losses.

Realized foreign exchange gains or losses arise from U.S. denominated transactions such as interest payments, debt repayments and hedging settlements. There were no cash realized foreign exchange gains during the quarter, however a non-cash realized gain of \$2.5 million was recorded during the quarter relating to a debt repayment of \$30 million made during the quarter. This debt repayment was financed with the Trust's credit facility and therefore is considered to be a non-cash transaction.

Unrealized foreign exchange gains and losses are due to revaluation of U.S. denominated debt balances. The volatility of the Canadian dollar during the reporting period has a direct impact on the unrealized component of the foreign exchange gain or loss. The unrealized gain or loss impacts net income but does not impact cash flow from operating activities as it is a non-cash amount. From June 30, 2009 to September 30, 2009, the Cdn\$/US\$ exchange rate decreased from 1.16 to 1.07 resulting in an unrealized gain of \$32.4 million on U.S. dollar denominated debt.

Taxes

In the third quarter of 2009, a future income tax recovery of \$5.7 million was included in income compared to an expense of \$48.4 million in the third quarter of 2008. The large expense in 2008 was attributable to the unrealized risk management contract gains recorded during the same period.

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

Management continues to work on the plan for converting ARC Energy Trust to a corporation on January 1, 2011. After the conversion, the corporation would expect to allocate its cash flow among funding 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 \$2.2 billion of income tax pools, taxable income will be reduced or potentially eliminated for the initial period post conversion. The \$2.2 billion of income tax pools (detailed in Table 18) are deductible at various rates and annual deductions associated with the initial tax pools will decline over time.

Table 18

Income Tax Pool type	Cdn \$ millions at September 30, 2009	Annual deductibility
Canadian Oil and Gas Property Expense	959.5	10% declining balance
Canadian Development Expense	384.6	30% declining balance
Canadian Exploration Expense	98.9	100%
Un-depreciated Capital Cost	388.3	Primarily 25% declining balance
Non-Capital Losses	166.5	100%
Research and Experimental Expenditures	0.8	100%
Other	16.2	Various rates, 7% declining balance to 20%
Total Federal Tax Pools	2,014.8	
Additional Alberta Tax Pools	155.5	Various rates, 25% declining balance to 100%
Total Federal and Provincial Pools	2,170.3	

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

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

Depletion, Depreciation and Accretion of Asset Retirement Obligation

The depletion, depreciation and accretion (“DD&A”) rate increased to \$16.55 per boe in the third quarter of 2009 from \$15.79 per boe in the third quarter of 2008. The Trust posted a large increase in proved reserves at year-end 2008; however, these reserves were offset by a significant increase in the future development costs required to convert proven undeveloped reserves to proven producing reserves.

A breakdown of the DD&A rate is summarized in Table 19:

Table 19

DD&A Rate (\$ millions except per boe amounts)	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	2009	2008	% Change
Depletion of oil and gas assets ⁽¹⁾	93.3	91.1	2	283.3	276.5	2
Accretion of asset retirement obligation ⁽²⁾	2.4	2.3	4	7.0	6.9	1
Total DD&A	95.7	93.4	2	290.3	283.4	2
DD&A rate per boe	16.55	15.79	5	16.65	15.90	5

(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 \$96.2 million in the third quarter of 2009 compared to \$136.4 million in the same period of 2008. This amount was incurred on drilling and completions, geological, geophysical and facilities expenditures.

Of the total amount spent in the third quarter, \$52.7 million was spent on the Montney resource play while the remaining \$43.5 million was spent on the remainder of the Trust’s conventional portfolio, which has produced strong production results despite the reduced capital re-investment in 2009.

In addition to capital expenditures on development activities during the third quarter, the Trust completed small property acquisitions of \$6.8 million and a small acquisition of undeveloped land for \$0.4 million. The Trust completed property dispositions of \$37.3 million that included a previously disclosed disposition of non-core assets in southeast Saskatchewan for proceeds of \$33.5 million. This disposition will have no material impact on the forecast production volumes for the year.

For the remainder of 2009, the Trust expects to drill 39 gross wells (38 net wells) on operated properties, complete all wells in inventory and proceed with construction of the Dawson gas plant that is expected to be operational by early second quarter of 2010. Total capital expenditures are forecast to be \$365 million in 2009.

Table 21a

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

	Nine Months Ended September 30, 2009			Nine Months Ended September 30, 2008		
	Capital Expenditures	Net Acquisitions	Total Expenditures	Capital Expenditures	Net Acquisitions	Total Expenditures
Expenditures	242.3	(21.6)	220.7	379.1	23.4	402.5
Per cent funded by:						
Cash flow from operating activities	51%	-	56%	77%	-	72%
Proceeds from Distribution re-investment plan ("DRIP")	21%	-	23%	23%	38%	24%
Debt/(Excess funding) ⁽¹⁾	28%	100%	21%	-	62%	4%
	100%	100%	100%	100%	100%	100%

⁽¹⁾ The Trust's debt balance was reduced by \$240 million with the net proceeds of the equity offering completed in the first quarter. These proceeds are intended to fund a portion of ARC's expenditures in the Montney resource play.

Asset Retirement Obligation and Reclamation Fund

At September 30, 2009, the Trust recorded an Asset Retirement Obligation ("ARO") of \$145.6 million (\$141.5 million at December 31, 2008) for future abandonment and reclamation of the Trust's properties.

Included in the September 30, 2009 ARO balance was a \$1 million increase related to development activities and changes in estimates in the first nine months of 2009, \$7 million for accretion expense in the period and a reduction of \$3.9 million for actual abandonment expenditures incurred in the first nine months of 2009.

ARC's reclamation funds held \$31.8 million as at September 30, 2009. Under the terms of the Trust's investment policy, reclamation fund investments and excess cash can only be invested in Canadian or U.S. Government securities, investment grade corporate bonds, or investment grade short-term money market securities.

Capitalization, Financial Resources and Liquidity

A breakdown of the Trust's capital structure is outlined in Table 22, as at September 30, 2009 and December 31, 2008:

Table 22

Capital Structure and Liquidity

(\$ millions except per cent and ratio amounts)	September 30, 2009	December 31, 2008
Net debt obligations ⁽¹⁾	705.4	961.9
Market value of trust units and exchangeable shares ⁽²⁾	4,809.6	4,405.9
Total capitalization ⁽³⁾	5,515.0	5,367.8
Net debt as a percentage of total capitalization	12.8%	17.9%
Net debt to annualized YTD cash flow from operating activities	1.5	1.0

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

⁽²⁾ Calculated using the total trust units outstanding at September 30 and December 31 including the total number of trust units issuable for exchangeable shares at September 30 and December 31 multiplied by the closing trust unit price of \$20.20 and \$20.10 at September 30, 2009 and December 31, 2008, respectively.

⁽³⁾ Total capitalization as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Total capitalization is not intended to represent the total funds from equity and debt received by the Trust.

At September 30, 2009, the Trust's current credit facilities comprised Cdn\$355 million in senior secured notes currently outstanding, a Cdn\$800 million syndicated bank credit facility, of which Cdn\$268.1 million was outstanding and a Cdn\$25 million demand working capital facility, of which \$14 million was outstanding. The credit facility syndicate includes 11 domestic and international banks. The Trust's debt agreements contain a number of covenants all of which were met as at September 30, 2009; these agreements are available at www.SEDAR.com.

As at September 30, 2009, the Trust has approximately \$680 million of unused credit available: \$532 million under its credit facility, and \$148 million available to draw long-term notes under a master shelf agreement with an insurance company.

As a result of the weakened global economic situation, the Trust along with all other oil and gas entities may have restricted access to capital and increased borrowing costs. Although the Trust's business and asset base have not changed, the lending capacity of all financial institutions has been diminished and risk premiums have increased. These issues will impact the Trust as it reviews financing alternatives for the 2010 capital program, assesses potential future acquisition opportunities and manages future cash flow decremented by lower commodity prices and higher borrowing costs. The Trust intends to finance its 2010 capital program with cash flow, existing credit facilities, proceeds from the DRIP, potential asset dispositions and new borrowings or equity if necessary. Beyond that, the Trust may need to access additional capital and/or curtail capital expenditure plans and will look to do so in the most cost effective manner possible.

Unitholders' Equity

At September 30, 2009, there were 235.7 million trust units issued and issuable for exchangeable shares, an increase of 19.3 million trust units from December 31, 2008 due mostly to the issuance of 15.5 million trust units as part of an equity offering in February 2009.

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 nine months of 2009, the Trust raised proceeds of \$51.7 million and issued 3.3 million trust units pursuant to the DRIP at an average price of \$15.73 per unit.

Distributions

ARC declared distributions of \$70.6 million (\$0.30 per unit), representing 56 per cent of 2009 third quarter cash flow from operating activities compared to distributions of \$171.3 million (\$0.80 per unit) representing 68 per cent of cash flow from operating activities in the third quarter of 2008.

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

- The portion of capital expenditures that are funded with cash flow from operating activities. In the first nine months of 2009, the Trust withheld approximately 35 per cent of cash flow from operating activities to fund 51 per cent of the capital program excluding acquisitions. The remaining portion of capital expenditures was financed by proceeds from the DRIP program, proceeds from net dispositions and debt.
- An annual contribution to the reclamation funds, with \$11.3 million scheduled to be contributed in 2009. The reclamation funds are segregated bank accounts or subsidiary trusts and the balances will be drawn on in future periods as the Trust incurs abandonment and reclamation costs over the life of its properties.
- Debt principal repayments on the Trust's credit facility from time to time as determined by the board of directors. The Trust's current debt level is well within the covenants specified in the debt agreements and, accordingly, there are no current mandatory requirements for repayment.
- Income taxes that are not passed on to unitholders. The Trust has a liability for future income taxes due to the excess of book value over the tax basis of the assets of the Trust and its corporate subsidiaries. The Trust currently, and up until January 1, 2011, may minimize or eliminate cash income taxes in corporate subsidiaries by maximizing deductions, however in future periods there may be cash income taxes if deductions are not sufficient to eliminate taxable income. Taxability of the Trust is currently passed on to unitholders in the form of taxable distributions whereby corporate income taxes are eliminated at the Trust level. The Trust taxation legislation, which will take effect in 2011, will result in taxes payable at the Trust level and therefore distributions to unitholders would decrease if ARC remained as a trust.
- Working capital requirements as determined by the board of directors. Certain working capital amounts may be deducted from cash flow from operating activities, however such amounts would be minimal and the Trust does not anticipate any such deductions in the foreseeable future.
- The Trust has certain obligations for future payments relative to employee long-term incentive compensation under the Whole Unit Plan. Presently, the Trust estimates that \$25 million to \$90.6 million will be paid out pursuant to such commitments in 2010 through 2012 subject to vesting provisions and future performance of the Trust. These amounts will reduce cash flow from operating activities and may in turn reduce distributions in future periods.

Cash flow from operating activities and distributions in total and per unit are summarized in Table 23 and Table 23a:

Table 2

Cash flow from operating activities and distributions	Three Months Ended September 30			Three Months Ended September 30		
	2009 (\$ millions)	2008	% Change	2009 (\$ per unit)	2008	% Change
Cash flow from operating activities	125.6	251.4	(50)	0.53	1.16	(54)
Net reclamation fund contributions ⁽¹⁾	(2.3)	(1.7)	35	(0.01)	(0.01)	-
Capital expenditures funded with cash flow from operating activities	(52.7)	(78.4)	(33)	(0.22)	(0.36)	(39)
Other ⁽²⁾	-	-	-	-	0.01	-
Distributions	70.6	171.3	(59)	0.30	0.80	(62)

Table 23a

Cash flow from operating activities and distributions	Nine Months Ended September 30			Nine Months Ended September 30		
	2009 (\$ millions)	2008	% Change	2009 (\$ per unit)	2008	% Change
Cash flow from operating activities	354.2	734.8	(52)	1.51	3.41	(56)
Net reclamation fund contributions ⁽¹⁾	(3.1)	(0.9)	244	(0.01)	-	-
Capital expenditures funded with cash flow from operating activities	(123.5)	(291.1)	(58)	(0.53)	(1.35)	(61)
Other ⁽²⁾	-	-	-	0.01	0.02	(50)
Distributions	227.6	442.8	(49)	0.98	2.08	(53)

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

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

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

- To maintain a level of distributions that, in normal times, in the opinion of Management and the Board of Directors, is sustainable for a minimum period of six months after factoring in the impact of current commodity prices on cash flows. The Trust's objective is to normalize the effect of volatility of commodity prices rather than to pass on that volatility to unitholders in the form of fluctuating monthly distributions.
- To ensure that the Trust's financial flexibility is maintained by a review of the Trust's debt to equity and debt to cash flow from operating activities levels. The use of cash flow from operating activities and proceeds from equity offerings to fund capital development activities reduces the requirements of the Trust to use debt to finance these expenditures. In the first nine months of 2009, the Trust funded 51 per cent of capital development activities with a portion of cash flow from operating activities. Distributions and the actual amount of cash flows withheld to fund the Trust's capital expenditure program is dependent on the commodity price environment and is subject to the approval and discretion of the Board of Directors.

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

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

Environmental Initiatives Impacting the Trust

There are no new environmental initiatives impacting the Trust at this time.

Contractual Obligations and Commitments

The Trust has contractual obligations in the normal course of operations including purchase of assets and services, operating agreements, transportation commitments, sales commitments, royalty obligations, and lease rental obligations and employee agreements. These obligations are of a recurring and consistent nature and impact the Trust's cash flows in an ongoing manner. The Trust also has contractual obligations and commitments that are of a less routine nature as disclosed in Table 24.

Table 24

	Payments due by period				Total
	1 year	2-3 Years	4-5 years	Beyond 5 years	
Debt repayments ⁽¹⁾	31.5	350.6	109.8	145.2	637.1
Interest payments ⁽²⁾	20.7	37.8	27.6	26.2	112.3
Reclamation fund contributions ⁽³⁾	5.3	9.5	8.3	67.9	91.0
Purchase commitments	25.9	13.3	4.5	2.6	46.3
Transportation commitments ⁽⁴⁾	3.5	21.9	24.6	7.8	57.8
Operating leases	5.1	11.2	14.8	76.3	107.4
Risk management contract premiums ⁽⁵⁾	5.5	0.3	-	-	5.8
Total contractual obligations	97.5	444.6	189.6	326.0	1,057.7

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

⁽²⁾ Fixed interest payments on senior secured notes.

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

⁽⁴⁾ Fixed payments for transporting production from the Dawson gas plant, expected to be operational in early second quarter of 2010.

⁽⁵⁾ Fixed premiums to be paid in future periods on certain commodity risk management contracts.

The above noted risk management contract premiums are part of the Trust's commitments related to its risk management program and have been recorded at fair market value at September 30, 2009 on the balance sheet as part of risk management contracts. In addition to the premiums, the Trust has commitments related to its risk management program.

The Trust enters into commitments for capital expenditures in advance of the expenditures being made. At any given point in time, it is estimated that the Trust has committed to capital expenditures equal to approximately one quarter of its capital budget by means of giving the necessary authorizations to incur the capital in a future period. The Trust's 2009 capital budget has been approved by the Board at \$365 million. This commitment has not been disclosed in the commitment table (Table 24) as it is of a routine nature and is part of normal course of operations for active oil and gas companies and trusts.

The 2009 capital budget of \$365 million includes \$11 million for leasehold development costs related to the Trust's new office space in downtown Calgary. These costs will be incurred throughout 2009 with additional costs to be incurred in 2010. The operating lease commitments for the new space begin in the first quarter of 2010 and are included in Table 24.

The Trust is involved in litigation and claims arising in the normal course of operations. Management is of the opinion that pending litigation will not have a material adverse impact on the Trust's financial position or results of operations and therefore the commitment table (Table 24) does not include any commitments for outstanding litigation and claims.

The Trust has certain sales contracts with aggregators whereby the price received by the Trust is dependent upon the contracts entered into by the aggregator. This commitment has not been disclosed in the commitment table (Table 24) as it is of a routine nature and is part of normal course of operations.

Off Balance Sheet Arrangements

The Trust has certain lease agreements, all of which are reflected in the Contractual Obligations and Commitments table (Table 24), which were entered into in the normal course of operations. All leases have been treated as

operating leases whereby the lease payments are included in operating expenses or G&A expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases in the balance sheet as of September 30, 2009.

Critical Accounting Estimates

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

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

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

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

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

Internal Control over Financial Reporting

ARC is required to comply with National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings", otherwise referred to as Canadian SOX ("C-Sox"). The certification of interim filings for the interim period ended September 30, 2009 requires that the Trust disclose in the interim MD&A any changes in the Trust's internal control over financial reporting that occurred during the period that has materially affected, or is reasonably likely to materially affect the Trust's internal control over financial reporting. The Trust confirms that no such changes were made to the internal controls over financial reporting during the first nine months of 2009.

Financial Reporting Update

Future Accounting Changes

International Financial Reporting Standards ("IFRS")

In April 2008, the CICA published the exposure draft "Adopting IFRS in Canada". The exposure draft proposes to incorporate IFRS into the CICA Accounting Handbook effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. At this date, publicly accountable enterprises will be required to prepare financial statements in accordance with IFRS.

The Trust has commenced the process to transition from current Canadian GAAP to IFRS. Internal staff has been appointed to lead the conversion project along with sponsorship from the leadership team. Regular progress reporting to the audit committee of the Board of Directors on the status of the IFRS conversion has been implemented.

ARC's project consists of three key phases:

- Scoping and diagnostic phase – this phase involves performing a high level impact analysis to identify areas that may be affected by the transition to IFRS. The results of this analysis are priority ranked according to complexity and the amount of time required to assess the impact changes in transitioning to IFRS.
- Impact analysis and evaluation phase – during this phase, items identified in the diagnostic are addressed according to the priority levels assigned to them. This phase involves analysis of policy

choices allowed under IFRS and their impact on the financial statements. In addition, certain potential differences are further investigated to assess whether there may be a broader impact to the Trust's debt agreements, compensation arrangements or management reporting systems. The conclusion of the impact analysis and evaluation phase will require the audit committee of the Board of Directors to review and approve all accounting policy choices as proposed by Management.

- Implementation phase – involves implementation of all changes approved in the impact analysis phase and will include changes to information systems, business processes, modification of agreements and training of all staff who are impacted by the conversion.

The Trust has completed the scoping and diagnostic phase and expects to complete the impact analysis and evaluation phase during the fourth quarter of 2009.

In July 2009, the international accounting standards board issued amendments to IFRS 1, "First-Time Adoption of International Financial Reporting Standards" ("IFRS 1"). 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. The amendment issued in July provides the option to value the property, plant and equipment ("PP&E") assets at their deemed cost being the net book value assigned to these assets as at the date of transition, January 1, 2010. This amendment is permissible for entities, such as the Trust, who currently follow the full cost accounting guideline under Canadian GAAP that accumulates all oil and gas assets into one cost centre. Under IFRS, the Trust's PP&E assets must be divided into smaller cost centers. The net book value of the assets on the date of transition will be allocated to the new cost centers on the basis of the Trust's reserve values at that point in time. As this is one of the Trust's largest differences from Canadian GAAP to IFRS, the Trust can now assess that this area will not create material changes to the Trust's financial results upon transition.

Non-GAAP Measures

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

Forward-looking Information and Statements

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

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

The forward-looking information and statements included in this news release are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; changes in the demand for or supply of ARC's products; unanticipated operating results or production declines; changes in tax

or environmental laws, royalty rates or other regulatory matters; changes in development plans of ARC or by third party operators of ARC's properties, increased debt levels or debt service requirements; inaccurate estimation of ARC's oil and gas reserve and resource volumes; limited, unfavorable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; and certain other risks detailed from time to time in ARC's public disclosure documents (including, without limitation, those risks identified in this news release and in ARC's Annual Information Form).

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

Additional Information

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

QUARTERLY HISTORICAL REVIEW

(Cdn \$ millions, except per unit amounts)	2009			2008			2007	
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
FINANCIAL								
Revenue before royalties	239.2	235.2	225.2	300.8	485.7	512.0	407.9	338.0
Per unit ⁽¹⁾	1.01	0.99	0.98	1.38	2.24	2.38	1.91	1.59
Cash flow from operating activities	125.6	104.3	124.3	209.4	251.4	273.4	209.9	173.7
Per unit – basic ⁽¹⁾	0.53	0.44	0.54	0.96	1.16	1.27	0.98	0.82
Per unit - diluted	0.53	0.44	0.54	0.96	1.16	1.27	0.98	0.82
Net income	68.9	66.1	22.3	82.7	311.7	57.3	81.3	106.3
Per unit – basic ⁽²⁾	0.29	0.28	0.10	0.38	1.46	0.27	0.39	0.51
Per unit - diluted	0.29	0.28	0.10	0.38	1.46	0.27	0.39	0.51
Distributions	70.6	75.0	82.0	127.2	171.3	144.7	126.8	125.8
Per unit – basic ⁽³⁾	0.30	0.32	0.36	0.59	0.80	0.68	0.60	0.60
Total assets	3,642.9	3,672.5	3,733.1	3,766.7	3,687.5	3,664.3	3,592.6	3,533.0
Total liabilities	1,278.4	1,323.1	1,392.1	1,624.6	1,530.8	1,689.6	1,560.4	1,491.3
Net debt outstanding ⁽⁴⁾	705.4	737.6	781.5	961.9	773.2	756.1	770.1	752.7
Weighted average trust units ⁽⁵⁾	237.7	236.6	228.9	218.3	216.6	215.2	213.8	212.5
Trust units outstanding and issuable ⁽⁵⁾	238.1	237.1	236.0	219.2	217.4	215.8	214.7	213.2
CAPITAL EXPENDITURES								
Geological and geophysical	3.0	5.0	2.8	3.7	1.3	16.4	5.5	3.0
Land	4.5	0.2	0.2	17.1	18.6	57.8	28.8	42.6
Drilling and completions	61	18.6	68.5	117.1	91.4	32.6	64.4	75.2
Plant and facilities	26.1	23.6	25.1	30.5	24.2	24.1	11.6	17.9
Other capital	1.6	1.5	0.6	1.0	0.9	0.4	1.0	0.6
Total capital expenditures	96.2	48.9	97.2	169.4	136.4	131.3	111.3	139.3
Property acquisitions (dispositions) net	(30.1)	2.3	6.2	27.6	13.1	0.3	10.1	5.0
Total capital expenditures and net acquisitions	66.1	51.2	103.4	197.0	149.5	131.6	121.4	144.3
OPERATING								
Production								
Crude oil (bbl/d)	26,921	26,917	28,806	28,935	28,509	27,541	29,064	28,682
Natural gas (mmcf/d)	193.1	200.2	193.8	195.1	192.0	194.7	204.3	187.4
Natural gas liquids (bbl/d)	3,717	3,679	3,764	3,858	3,822	3,906	3,856	4,067
Total (boe per day 6:1)	62,824	63,969	64,872	65,313	64,325	63,896	66,976	63,989
Average prices								
Crude oil (\$/bbl)	67.74	62.74	46.44	56.26	114.20	118.32	89.72	77.53
Natural gas (\$/mcf)	3.25	3.73	5.20	7.48	8.68	10.41	7.80	6.32
Natural gas liquids (\$/bbl)	38.92	38.89	38.86	45.22	82.87	82.29	68.54	62.75
Oil equivalent (\$/boe)	41.31	40.32	38.40	45.93	81.42	87.73	66.67	57.26
TRUST UNIT TRADING PRICES (based on intra-day trading)								
High	20.20	19.25	20.90	22.55	33.30	33.95	27.06	21.55
Low	15.48	14.12	11.73	15.01	22.33	25.19	20.00	18.90
Close	20.20	17.81	14.15	20.10	23.10	33.95	26.38	20.40
Average daily volume (thousands)	1,038	988	1,240	1,523	841	659	863	624

- (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 September 30 and December 31

(Cdn\$ millions)	2009		2008	
ASSETS				
Current assets				
Cash and cash equivalents (Note 3)	\$	-	\$	40.0
Accounts receivable (Note 4)		104.3		110.0
Prepaid expenses		19.3		16.8
Risk management contracts (Note 8)		5.0		24.4
Future income taxes		6.4		3.9
		135.0		195.1
Reclamation funds		31.8		28.2
Risk management contracts (Note 8)		3.6		9.2
Property, plant and equipment		3,314.9		3,376.6
Goodwill		157.6		157.6
Total assets	\$	3,642.9	\$	3,766.7
LIABILITIES				
Current liabilities				
Accounts payable and accrued liabilities	\$	168.3	\$	194.4
Distributions payable		23.6		32.5
Risk management contracts (Note 8)		12.1		23.5
		204.0		250.4
Risk management contracts (Note 8)		1.3		3.4
Long-term debt (Note 5)		637.1		901.8
Accrued long-term incentive compensation (Note 13)		8.3		14.2
Asset retirement obligations (Note 6)		145.6		141.5
Future income taxes		282.1		313.3
Total liabilities		1,278.4		1,624.6
NON-CONTROLLING INTEREST				
Exchangeable shares (Note 9)		37.8		42.4
UNITHOLDERS' EQUITY				
Unitholders' capital (Note 10)		2,900.3		2,600.7
Deficit (Note 11)		(573.2)		(502.9)
Accumulated other comprehensive (loss) income (Note 11)		(0.4)		1.9
Total unitholders' equity		2,326.7		2,099.7
Total liabilities and unitholders' equity	\$	3,642.9	\$	3,766.7

See accompanying notes to the Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF INCOME AND DEFICIT (unaudited)
For the three and nine months ended September 30

(Cdn\$ millions, except per unit amounts)	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	2009	2008
REVENUES				
Oil, natural gas and natural gas liquids	\$ 239.2	\$ 485.7	\$ 699.6	\$ 1,405.6
Royalties	(37.7)	(88.8)	(102.2)	(252.8)
	201.5	396.9	597.4	1,152.8
Gain (loss) on risk management contracts (Note 8)				
Realized	6.7	(34.3)	21.1	(108.5)
Unrealized	(0.7)	187.5	(7.9)	26.0
	207.5	550.1	610.6	1,070.3
EXPENSES				
Transportation	4.8	4.8	15.3	13.8
Operating	55.9	60.2	179.2	180.8
General and administrative	15.9	3.5	38.5	47.2
Provision for non-recoverable accounts receivable (Note 4)	(0.4)	-	(0.4)	18.0
Interest and financing charges (Note 5)	6.4	7.8	19.8	24.9
Depletion, depreciation and accretion	95.7	93.4	290.3	283.4
(Gain) loss on foreign exchange	(34.9)	16.3	(60.3)	28.1
	143.4	186.0	482.4	596.2
Capital and other taxes	(0.2)	-	(0.2)	-
Future income tax recovery (expense)	5.7	(48.4)	30.9	(17.8)
Net income before non-controlling interest	69.6	315.7	158.9	456.3
Non-controlling interest (Note 9)	(0.7)	(4.0)	(1.6)	(6.0)
Net income	\$ 68.9	\$ 311.7	\$ 157.3	\$ 450.3
Deficit, beginning of period	\$ (571.5)	\$ (598.8)	\$ (502.9)	\$ (465.9)
Distributions paid or declared (Note 12)	(70.6)	(171.3)	(227.6)	(442.8)
Deficit, end of period (Note 11)	\$ (573.2)	\$ (458.4)	\$ (573.2)	\$ (458.4)
Net income per unit (Note 10)				
Basic	\$ 0.29	\$ 1.46	\$ 0.68	\$ 2.12
Diluted	\$ 0.29	\$ 1.46	\$ 0.68	\$ 2.12

See accompanying notes to the Consolidated Financial Statements

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

For the three and nine months ended September 30

(Cdn\$ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	2009	2008
Net income	\$ 68.9	\$ 311.7	\$ 157.3	\$ 450.3
Other comprehensive income (loss), net of tax				
Losses on financial instruments designated as cash flow hedges ⁽¹⁾	(0.5)	(0.8)	(3.4)	(2.8)
De-designation of cash flow hedge ⁽²⁾ (Note 8)	-	-	-	10.0
Gains and losses on financial instruments designated as cash flow hedges in prior periods realized in net income in the current period ⁽³⁾ (Note 8)	0.2	(0.5)	0.8	(2.0)
Net unrealized gains (losses) on available-for- sale reclamation funds' investments ⁽⁴⁾	0.5	(0.1)	0.3	(0.1)
Other comprehensive income (loss)	0.2	(1.4)	(2.3)	5.1
Comprehensive income	\$ 69.1	\$ 310.3	\$ 155.0	\$ 455.4
Accumulated other comprehensive (loss) income, beginning of period	(0.6)	3.6	1.9	(2.9)
Other comprehensive income (loss)	0.2	(1.4)	(2.3)	5.1
Accumulated other comprehensive (loss) income, end of period (Note 11)	\$ (0.4)	\$ 2.2	\$ (0.4)	\$ 2.2

⁽¹⁾ Amounts are net of tax of \$0.2 million and \$1.2 million, respectively, for the three months and nine months ended September 30, 2009 (net of tax of \$0.3 million and \$1 million, respectively, for the three and nine months ended September 30, 2008).

⁽²⁾ Amount is net of tax of \$3.6 million for the nine months ended September 30, 2008.

⁽³⁾ Amounts are net of tax of \$0.1 million and \$0.3 million, respectively, for the three and nine months ended September 30, 2009 (net of tax of \$0.2 million and \$0.7 million, respectively, for the three and nine months ended September 30, 2008).

⁽⁴⁾ Amounts are net of tax of \$0.2 million and \$0.1 million, respectively, for the three and nine months ended September 30, 2009 (nominal future income tax impact for the three and nine months ended September 30, 2008).

See accompanying notes to the Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)
For the three and nine months ended September 30

(Cdn\$ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	\$ 68.9	\$ 311.7	\$ 157.3	\$ 450.3
Add items not involving cash:				
Non-controlling interest (Note 9)	0.7	4.0	1.6	6.0
Future income tax (recovery) expense	(5.7)	48.4	(30.9)	17.8
Depletion, depreciation and accretion	95.7	93.4	290.3	283.4
Non-cash loss (gain) on risk management contracts (Note 8)	0.7	(187.5)	7.9	(26.0)
Non-cash (gain) loss on foreign exchange	(34.9)	15.5	(60.2)	26.9
Non-cash trust unit incentive compensation (recovery) expense (Note 13)	(0.6)	(6.9)	(4.1)	5.1
Expenditures on site restoration and reclamation (Note 6)	(1.0)	(1.8)	(3.9)	(7.8)
Change in non-cash working capital	1.8	(25.4)	(3.8)	(20.9)
	125.6	251.4	354.2	734.8
CASH FLOWS FROM FINANCING ACTIVITIES				
Repayment of long-term debt under revolving credit facilities, net	(35.6)	(6.6)	(345.2)	(45.6)
Issue of Senior Secured Notes	-	-	152.9	-
Repayment of Senior Secured Notes	-	-	(12.6)	-
Issue of trust units	0.5	0.5	254.5	4.3
Trust unit issue costs	(0.2)	-	(13.3)	-
Cash distributions paid (Note 12)	(54.9)	(132.5)	(186.2)	(341.2)
Change in non-cash working capital	3.9	1.7	5.9	1.1
	(86.3)	(136.9)	(144.0)	(381.4)
CASH FLOWS FROM INVESTING ACTIVITIES				
Acquisition of petroleum and natural gas properties	(2.2)	(13.1)	(10.7)	(23.6)
Proceeds on disposition of petroleum and natural gas properties	32.3	-	32.3	0.2
Capital expenditures	(96.5)	(137.6)	(242.9)	(378.0)
Net reclamation fund contributions	(2.3)	(1.7)	(3.1)	(0.9)
Change in non-cash working capital	29.4	37.9	(25.8)	41.9
	(39.3)	(114.5)	(250.2)	(360.4)
DECREASE IN CASH AND CASH EQUIVALENTS	-	-	(40.0)	(7.0)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	-	-	40.0	7.0
CASH AND CASH EQUIVALENTS, END OF PERIOD	\$ -	\$ -	\$ -	\$ -

See accompanying notes to the Consolidated Financial Statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

September 30, 2009 and 2008
(all tabular amounts in Cdn\$ millions, except per unit amounts)

1. SUMMARY OF ACCOUNTING POLICIES

The unaudited interim Consolidated Financial Statements follow the same accounting policies as the most recent annual audited financial statements, except as highlighted in Note 2. The interim Consolidated Financial Statement note disclosures do not include all of those required by Canadian generally accepted accounting principles (“GAAP”) applicable for annual Consolidated Financial Statements. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with the audited Consolidated Financial Statements included in the Trust’s 2008 annual report.

2. NEW ACCOUNTING POLICIES

Current Year Accounting Changes

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

This standard was adopted prospectively.

Future Accounting Changes

A. Business Combinations

The CICA issued Handbook section 1582 “Business Combinations” that replaces the previous business combinations standard. Under this guidance, the purchase price used in a business combination is based on the fair value of shares exchanged at the market price at acquisition date. Under the current standard, the purchase price used is based on the market price of shares for a reasonable period before and after the date the acquisition is agreed upon and announced. In addition, the guidance generally requires all acquisition costs to be expensed. Current standards allow for the capitalization of these costs as part of the purchase price. This new Section also addresses contingent liabilities, which will be required to be recognized at fair value on acquisition, and subsequently remeasured at each reporting period until settled. Currently, standards require only contingent liabilities that are payable to be recognized. The new guidance requires negative goodwill to be recognized in earnings rather than the current standard of deducting from non-current assets in the purchase price allocation. This standard will be effective for the Trust on January 1, 2011, with prospective application.

B. Consolidated Financial Statements and Non-controlling Interest

The CICA issued Handbook Sections 1601 “Consolidated Financial Statements”, and 1602 “Non-controlling Interests”, which replaces existing guidance under Section 1600 “Consolidated Financial Statements”. Section 1601 establishes standards for the preparation of Consolidated Financial Statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in Consolidated Financial Statements subsequent to a business combination. These standards will be effective for the Trust for business combinations occurring on or after January 1, 2011.

C. Financial Instruments – Disclosures

The CICA issued amendments to Handbook Section 3862, Financial Instruments — Disclosures. The amendments include enhanced disclosures related to the fair value of financial instruments and the liquidity risk associated with financial instruments. The amendments will be effective for annual financial statements for fiscal years ending after September 30, 2009. The amendments are consistent with recent amendments to financial instrument disclosure standards in International Financial Reporting Standards “IFRS”. The Trust will include these additional disclosures in its annual Consolidated Financial Statements for the year ending December 31, 2009.

3. CASH AND CASH EQUIVALENTS

Cash equivalents are nil as at September 30, 2009 (\$40 million in Canadian Treasury Bills as at December 31, 2008).

4. FINANCIAL ASSETS AND CREDIT RISK

The majority of the credit exposure on accounts receivable at September 30, 2009 pertains to accrued revenue for September 2009 production volumes. The Trust 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 the Trust by the 25th day of the month following production. Joint interest receivables are typically collected within one to three months following production. At September 30, 2009, 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.

In the third quarter of 2009, the Trust recorded a recovery of \$0.4 million for amounts received on balances previously included in the Trust’s allowance for doubtful accounts. The Trust’s allowance for doubtful accounts was \$31.6 million as at September 30, 2009 and \$32 million as at December 31, 2008. During the first nine months of 2009 the Trust did not record any additional provision for non-collectible accounts receivable.

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 September 30, 2009, \$6.9 million of accounts receivable are past due, excluding amounts described above, all of which are considered to be collectable.

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

5. LONG-TERM DEBT

	September 30, 2009	December 31, 2008
Revolving credit facilities		
Syndicated credit facility – Cdn\$ denominated	\$ 213.4	\$ 399.5
Syndicated credit facility – US\$ denominated	54.7	240.6
Working capital facility	14.0	2.1
Senior secured notes		
5.42% US\$ Note	80.4	91.9
4.94% US\$ Note	12.9	14.7
4.62% US\$ Note	55.8	76.5
5.10% US\$ Note	67.0	76.5
7.19% US\$ Note	72.4	-
8.21% US\$ Note	37.5	-
6.50% Cdn\$ Note	29.0	-
Total long-term debt outstanding	\$ 637.1	\$ 901.8

Revolving Credit Facilities

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

Borrowings under the syndicated credit facility bear interest at bank prime (2.25 per cent at September 30, 2009, four per cent at December 31, 2008) or, at the Trust’s option, Canadian dollar bankers’ acceptances or U.S. dollar LIBOR loans, plus a stamping fee. At the option of the Trust, the lenders will review the syndicated credit facility each year and determine whether they will extend the revolving period for another year. In the event that the credit facility is not extended at any time before the maturity date, the loan balance will become repayable on the maturity date. The maturity date of the current syndicated credit facility is April 15, 2011. All drawings under the facility are subject to stamping fees. These stamping fees vary between a minimum of 60 basis points (“bps”) to a maximum of 110 bps.

As at September 30, 2009, the Trust had \$1.9 million in letters of credit (\$2 million in 2008), no subordinated debt, and was in compliance with all covenants.

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

Senior Secured Notes

The fair value of senior secured notes as at September 30, 2009, is \$349.3 million (\$289.9 million as at December 31, 2008), and is calculated as the present value of principal and interest payments discounted at the Trust's credit adjusted risk free rate.

Supplemental disclosures

Amounts of US\$16.4 million due under the senior secured notes and \$14 million due under the Trust's working capital facility in the next 12 months have not been included in current liabilities as Management has the ability and intent to refinance this amount through the syndicated credit facility.

Interest paid during the third quarter of 2009 was \$4.8 million less than interest expense (equal in the third quarter of 2008).

During the third quarter of 2009, the weighted-average interest rate under the credit facility was 0.9 per cent (3.6 per cent in 2008) and 1.2 per cent for the nine months ended September 30, 2009 (four per cent in 2008).

At September 30, 2009, the Trust had approximately \$680 million of total unused credit available.

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

6. ASSET RETIREMENT OBLIGATIONS

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

	Nine Months Ended September 30, 2009	Year Ended December 31, 2008
Balance, beginning of period	\$ 141.5	\$ 140.0
Increase in liabilities relating to development activities	0.5	2.0
Increase in liabilities relating to change in estimate	0.5	2.6
Settlement of reclamation liabilities during the period	(3.9)	(12.4)
Accretion expense	7.0	9.3
Balance, end of period	\$ 145.6	\$ 141.5

The Trust's weighted average credit adjusted risk free rate as at September 30, 2009 was 6.5 per cent (6.6 per cent as at December 31, 2008).

7. CAPITAL MANAGEMENT

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

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

The Trust manages the following capital:

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

When evaluating the Trust's capital structure, management's objective is to limit net debt to less than 2.0 times annualized cash flow from operating activities and 20 per cent of total capitalization. As at September 30, 2009 the Trust's net debt to annualized cash flow from operating activities ratio is 1.5 and its net debt to total capitalization ratio is 12.8 per cent.

	September 30, 2009	December 31, 2008
Long-term debt	637.1	901.8
Accounts payable and accrued liabilities	168.3	194.4
Distributions payable	23.6	32.5
Cash and cash equivalents, accounts receivable and prepaid expenses	(123.6)	(166.8)
Net debt obligations ⁽¹⁾	705.4	961.9
Trust units outstanding and issuable for exchangeable shares (millions)	238.1	219.2
Trust unit price ⁽²⁾	20.20	20.10
Market capitalization ⁽¹⁾	4,809.6	4,405.9
Net debt obligations ⁽¹⁾	705.4	961.9
Total capitalization ⁽¹⁾	5,515.0	5,367.8
Net debt as a percentage of total capitalization	12.8%	17.9%
Net debt obligations to annualized cash flow from operating activities	1.5	1.0

(1) Market capitalization, net debt obligations and total capitalization as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities.

(2) TSX close price as at September 30, 2009 and December 31, 2008 respectively.

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

In addition to internal capital management the Trust is subject to various covenants under its credit facilities. Compliance with these covenants is monitored on a quarterly basis and as at September 30, 2009 the Trust is in compliance with all covenants. Refer to Note 5 for further details.

8. MARKET RISK MANAGEMENT

The Trust is exposed to a number of market risks that are part of its normal course of business. The Trust has a risk management program in place that includes financial instruments as disclosed in 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 the Trust'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 the Trust'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 to the U.S. dollar and the West Texas Intermediate posting ("WTI") crude oil price.

Commodity price risk

The Trust's operational results and financial condition, and therefore the amount of distributions paid to unitholders, are largely dependent on the commodity prices received for 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 September 30, 2009. The sensitivity is based on a \$15 increase and \$15 decrease in the price of US\$ WTI crude oil and a \$2 increase and \$2 decrease in the price of Cdn\$ 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 September 30, 2009 and the Trust's next reporting date.

(\$ millions)	Increase in Commodity Price		Decrease in Commodity Price	
	Crude oil	Natural gas	Crude oil	Natural gas
Net income (decrease) increase	(12.2)	(8.1)	18.1	14.4

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 the Trust'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

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

If interest rates applicable to floating rate debt at September 30, 2009 were to have increased by 50 bps (0.5 per cent) it is estimated that the Trust's net income would decrease by \$1.1 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 the Trust has U.S. dollar denominated debt 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 significant positive or negative impact on distributions to unitholders.

As at September 30, 2009 no risk management contracts pertaining to foreign exchange were outstanding.

If foreign exchange rates applicable to U.S. denominated debt were to have increased or decreased by \$0.10Cdn\$/US\$ it is estimated that the Trust's net income for the period ended September 30, 2009 would decrease or increase by \$27 million, respectively. Increases and decreases in foreign exchange rates applicable to US\$ payables and receivables would have a nominal impact on the Trust's net income for the period ended September 30, 2009.

Risk Management Contracts

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

Following is a summary of all risk management contracts in place as at September 30, 2009 that do not qualify for hedge accounting:

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

Term	Contract	Volume bbl/d	Bought Put US\$/bbl	Sold Put US\$/bbl	Sold Call US\$/bbl	
1-Oct-09	31-Dec-09	Put Spread	2,500	\$55.00	\$40.00	-

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-Oct-09	31-Dec-09	Collar	3,000	\$70.00	-	\$82.50
1-Oct-09	31-Mar-10	Collar	1,000	\$65.00	-	\$80.00
1-Jan-10	31-Dec-10	Collar	4,000	\$70.00	-	\$90.00

(1) Monthly average

Financial Cdn\$ WTI Crude Oil Option Contracts ⁽²⁾

Term	Contract	Volume bbl/d	Bought Put Cdn\$/bbl	Sold Put Cdn\$/bbl	Sold Call Cdn\$/bbl	
1-Oct-09	31-Dec-09	Collar	2,000	\$65.00	-	\$75.00
1-Oct-09	31-Dec-09	Collar	1,000	\$70.00	-	\$80.00

(2) Monthly average

Financial AECO Natural Gas Option Contracts ⁽³⁾

Term	Contract	Volume GJ/d	Bought Put Cdn\$/GJ	Sold Put Cdn\$/GJ	Sold Call Cdn\$/GJ	
1-Oct-09	31-Oct-09	Collar	20,000	\$4.00	-	\$4.75
1-Oct-09	31-Oct-09	Collar	20,000	\$4.25	-	\$5.00
1-Oct-09	31-Dec-09	3-way collar	20,000	\$6.50	\$4.50	\$8.00
1-Nov-09	31-Dec-09	Collar	10,000	\$5.25	-	\$6.25
1-Nov-09	31-Dec-09	Collar	10,000	\$4.50	-	\$5.81
1-Nov-09	31-Dec-09	Collar	5,000	\$4.50	-	\$5.77
1-Nov-09	31-Dec-09	Collar	5,000	\$4.50	-	\$5.80

(3) AECO 7a monthly index

Financial AECO Natural Gas Swap Contracts ⁽⁴⁾

Term	Contract	Volume GJ/d	Swap Cdn\$/GJ	Bought Call Cdn\$/GJ	
1-Oct-09	31-Oct-09	Covered Swap	20,000	\$3.10	\$6.00 ⁽⁵⁾
1-Oct-09	31-Oct-09	Covered Swap	10,000	\$4.25	\$6.00
1-Oct-09	31-Dec-09	Swap	10,000	\$4.06	-
1-Nov-09	31-Dec-09	Swap	10,000	\$4.25	-
1-Nov-09	31-Dec-09	Swap	20,000	\$5.10	-
1-Jan-10	31-Dec-13	Swap	5,000	\$6.80	-

(4) AECO 7a monthly index

(5) AECO 5a monthly index

Energy Equivalent Swap

Term	Contract	Volume	Swap	
Financial AECO Natural Gas Sales Contract ⁽⁶⁾				
1-Oct-09	31-Dec-09	Swap	10,000 GJ/d	Cdn\$ 4.67/GJ
Financial Cdn\$ WTI Crude Oil Purchase Contract ⁽⁷⁾				
1-Oct-09	31-Dec-09	Swap	650 bbl/d	Cdn\$ 71.95/bbl

(6) AECO 5a monthly index

(7) Monthly average

Financial Basis Swap Contract ⁽⁸⁾				
Term		Contract	Volume mmbtu/d	Basis Swap US\$/mmbtu
1-Oct-09	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)

⁽⁸⁾ Receive Nymex Last Day (Ld) or Last 3 Day (L3d); pay AECO 7a monthly index

Financial Electricity Heat Rate Contracts ⁽⁹⁾							
Term		Contract	Volume MWh	AESO Power \$/MWh	AECO 5(a) \$/GJ	multiplied by	Heat Rate GJ/MWh
1-Jan-10	31-Dec-13	Heat Rate Swap	5	Receive AESO	Pay AECO 5(a)		x 9.0

⁽⁹⁾ Alberta Power Pool (monthly average 24x7), AECO 5a monthly index

Financial Electricity Contracts ⁽¹⁰⁾				
Term		Contract	Volume MWh	Bought Swap Cdn\$/MWh
1-Oct-09	31-Dec-12	Swap	5	\$72.495

⁽¹⁰⁾ Alberta Power Pool (monthly average 24x7)

Following is a summary of all risk management contracts in place as at September 30, 2009 that qualify for hedge accounting:

Financial Electricity Contracts ⁽¹¹⁾				
Term		Contract	Volume MWh	Bought Swap Cdn\$/MWh
1-Oct-09	31-Dec-09	Swap	15	\$59.33
1-Jan-10	31-Dec-10	Swap	5	\$63.00

⁽¹¹⁾ Alberta Power Pool (monthly average 24x7)

At September 30, 2009, the fair value of the contracts that were not designated as accounting hedges was a loss of \$4.5 million. The Trust recorded a gain on risk management contracts of \$13.2 million in the statement of income for the nine months ended September 30, 2009 (\$82.5 million loss in 2008). This amount includes the realized and unrealized gains and losses on risk management contracts that do not qualify as effective accounting hedges.

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

	Nine Months Ended September 30, 2009		Nine Months Ended September 30, 2008	
Fair value, beginning of period	\$	3.4	\$	(64.6)
Fair value, end of period ⁽¹⁾		(4.5)		(38.6)
Change in fair value of contracts in the period		(7.9)		26.0
Realized gain (loss) in the period		21.1		(108.5)
Gain (loss) on risk management contracts	\$	13.2	\$	(82.5)

(1) Intrinsic value of risk management contracts not designated as effective accounting hedges equals a loss of \$8.6 million at September 30, 2009 (\$24.7 million loss at September 30, 2008).

During 2007 the Trust entered into treasury rate lock contracts in order to manage the Trust's interest rate exposure on future debt issuances. During 2008 it was determined that the previously anticipated debt issuance was no longer expected to occur and the associated treasury rate lock contracts were unwound at a loss of \$13.6 million. The loss was reclassified from Other Comprehensive Income ("OCI"), net of tax \$10 million and recognized in net income.

The Trust's electricity contracts are intended to manage price risk on electricity consumption. Portions of the Trust's financial electricity contracts were designated as effective accounting hedges on their respective contract

dates. A realized loss of \$0.3 million and \$1.1 million for the three and nine months ended September 30, 2009 (gain of \$0.7 million and \$2.8 million respectively in 2008) has been included in operating costs on these electricity contracts. The accumulated unrealized fair value loss of \$0.3 million on these contracts has been recorded on the Consolidated Balance Sheet at September 30, 2009 with the movement in fair value recorded in OCI, net of tax. The fair value movement for the nine months ended September 30, 2009 is an unrealized loss of \$3.6 million. As at September 30, 2009 \$0.2 million of the 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 the Trust's financial risk management contracts that have been designated as effective accounting hedges:

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Fair value, beginning of period	\$ 3.3	\$ (3.4)
Change in fair value of financial electricity contracts	(3.6)	(0.4)
Change in fair value of treasury rate lock contracts prior to de-designation	-	(6.2)
Reclassification of loss on treasury rate lock contracts to net income	-	13.6
Fair value, end of period ⁽¹⁾	\$ (0.3)	\$ 3.6

(1) Intrinsic value of risk management contracts designated as effective accounting hedges equals a loss of \$0.3 million at September 30, 2009 (\$3.6 million gain at September 30, 2008).

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

9. EXCHANGEABLE SHARES

(units thousands)	Nine Months Ended September 30, 2009	Year Ended December 31, 2008
Balance, beginning of period	1,092	1,310
Exchanged for trust units ⁽¹⁾	(159)	(218)
Balance, end of period	933	1,092
Exchange ratio, end of period	2.67944	2.51668
Trust units issuable upon conversion, end of period	2,500	2,748

(1) During the first nine months of 2009, 159,291 ARL exchangeable shares were converted to trust units at an average exchange ratio of 2.55449, compared to 218,455 exchangeable shares at an average exchange ratio of 2.36901 during the year ended 2008.

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

	Nine Months Ended September 30, 2009	Year Ended December 31, 2008
Non-controlling interest, beginning of period	\$ 42.4	\$ 43.1
Reduction of book value for conversion to trust units	(6.2)	(7.6)
Current period net income attributable to non-controlling interest	1.6	6.9
Non-controlling interest, end of period	37.8	42.4
Accumulated earnings attributable to non-controlling interest	\$ 42.6	\$ 41.0

10. UNITHOLDERS' CAPITAL

(units thousands)	Nine Months Ended September 30, 2009		Year Ended December 31, 2008	
	Number of trust units	\$	Number of trust units	\$
Balance, beginning of period	216,435	2,600.7	210,232	2,465.7
Issued for cash	15,474	253.0	-	-
Issued on conversion of ARL exchangeable shares (Note 9)	407	6.2	517	7.6
Issued on exercise of employee rights	-	-	238	4.2
Distribution reinvestment program	3,335	51.7	5,448	123.2
Trust unit issue costs, net of tax ⁽¹⁾	-	(11.3)	-	-
Balance, end of period	235,651	2,900.3	216,435	2,600.7

(1) Amount is net of tax of \$2 million for the period ended September 30, 2009.

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

(units thousands)	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	2009	2008
Weighted average trust units ⁽¹⁾	235,182	213,859	231,976	212,480
Trust units issuable on conversion of exchangeable shares ⁽²⁾	2,500	2,727	2,500	2,727
Dilutive impact of rights ⁽³⁾	-	2	-	65
Diluted trust units and exchangeable shares	237,682	216,588	234,476	215,272

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

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

(3) There are no rights outstanding as of September 30, 2009 and therefore, no dilutive impact. Previously outstanding rights were dilutive and therefore were included in the diluted unit calculation for 2008.

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

11. DEFICIT AND ACCUMULATED OTHER COMPREHENSIVE (LOSS) INCOME

	September 30, 2009		December 31, 2008	
Accumulated earnings	\$	2,881.4	\$	2,724.1
Accumulated distributions		(3,454.6)		(3,227.0)
Deficit	\$	(573.2)	\$	(502.9)
Accumulated other comprehensive (loss) income		(0.4)		1.9
Deficit and accumulated other comprehensive (loss) income	\$	(573.6)	\$	(501.0)

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

	September 30, 2009		December 31, 2008	
Unrealized gains and losses on financial instruments designated as cash flow hedges	\$	(0.5)	\$	2.0
Net unrealized gains and losses on available-for-sale reclamation funds' investments		0.1		(0.1)
Accumulated other comprehensive (loss) income, end of period	\$	(0.4)	\$	1.9

12. 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 September 30		Nine Months Ended September 30	
	2009	2008	2009	2008
Cash flow from operating activities	\$ 125.6	\$ 251.4	\$ 354.2	\$ 734.8
Deduct:				
Cash withheld to fund current period capital expenditures	(52.7)	(78.4)	(123.5)	(291.1)
Net reclamation fund contributions	(2.3)	(1.7)	(3.1)	(0.9)
Distributions ⁽¹⁾	70.6	171.3	227.6	442.8
Accumulated distributions, beginning of period	3,384.0	2,928.5	3,227.0	2,657.0
Accumulated distributions, end of period	\$ 3,454.6	\$ 3,099.8	\$ 3,454.6	\$ 3,099.8
Distributions per unit ⁽²⁾	\$ 0.30	\$ 0.80	\$ 0.98	\$ 2.08
Accumulated distributions per unit, beginning of period	\$ 24.38	\$ 22.31	\$ 23.70	\$ 21.03
Accumulated distributions per unit, end of period ⁽³⁾	\$ 24.68	\$ 23.11	\$ 24.68	\$ 23.11

(1) Distributions include accrued and non-cash amounts of \$15.6 million and \$41.3 million for the three and nine months ended September 30, 2009 (\$39 million and \$102 million for the same periods in 2008).

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

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

13. WHOLE TRUST UNIT INCENTIVE PLAN

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

The Trust recorded non-cash compensation recovery of \$4million and \$0.1 million to general and administrative and operating expenses, respectively, and capitalized \$0.7 million to property, plant and equipment in the nine months ended September 30, 2009 for the estimated change in the Plan liability (\$4.6 million, \$0.5 million, and \$1.1 million for the nine months ended September 30, 2008). The non-cash compensation recovery was based on the September 30, 2009 unit price of \$20.20 (\$23.10 at September 30, 2008), accrued distributions, a performance multiplier, and the estimated number of units to be issued on maturity.

The following table summarizes the RTU and PTU movement for the nine months ended September 30, 2009:

	Number of RTUs (thousands)	Number of PTUs (thousands)
Balance, beginning of period	756	959
Granted	697	634
Vested	(355)	(262)
Forfeited	(43)	(24)
Balance, end of period	1,055	1,307

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

	September 30, 2009	December 31, 2008
Balance, beginning of period	\$ 31.9	\$ 30.3
Change in net liabilities in the period		
General and administrative expense	(4.0)	1.1
Operating expense	(0.1)	(0.1)
Property, plant and equipment	(0.7)	0.6
Balance, end of period ⁽¹⁾	\$ 27.1	\$ 31.9
Current portion of liability ⁽²⁾	19.3	18.8
Accrued long-term incentive compensation	\$ 8.3	\$ 14.2

⁽¹⁾ Includes \$0.5 million of recoverable amounts recorded in accounts receivable as at September 30, 2009 (\$1.1 million for 2008).

⁽²⁾ Included in Accounts payable and accrued liabilities on the Consolidated Balance Sheet.

During the first nine months of 2009, cash payments of \$16.6 million were made to employees relating to the Whole Unit Plan compared to \$18.3 million in 2008. In October 2008, vesting periods were revised from April and October to March and September of each year commencing in 2009.

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: the volumes and estimated value of ARC's oil and gas reserves; the life of ARC's reserves; the volume and product mix of ARC's oil and gas production; future oil and natural gas prices and ARC's commodity risk management programs; the amount of future asset retirement obligations; future liquidity and financial capacity; future results from operations and operating metrics; future costs, expenses and royalty rates; future interest costs; future development, exploration, acquisition and development activities (including drilling plans) and related capital expenditures, future tax treatment of income trusts and future taxes payable by ARC; and ARC's tax pools.

The forward-looking information and statements contained in this news release reflect several material factors and expectations and assumptions of ARC including, without limitation: that ARC will continue to conduct its operations in a manner consistent with past operations; the general continuance of current industry conditions; the continuance of existing (and in certain circumstances, the implementation of proposed) tax, royalty and regulatory regimes; the accuracy of the estimates of ARC's reserve 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.

ARC Energy Trust is one of Canada's largest conventional oil and gas royalty trusts with a current enterprise value of approximately \$5.4 billion. The Trust expects 2009 oil and gas production to average 63,000 to 64,000 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.

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