

MANAGEMENT DISCUSSION AND ANALYSIS

Basis of Presentation

The following is management's discussion and analysis ("MD&A") of Arsenal Energy Inc.'s ("Arsenal" or the "Company") unaudited operating and financial results for the three and six months ended June 30, 2010. It should be read in conjunction with the unaudited interim consolidated financial statements and related notes of the Company for the three and six months ended June 30, 2010 and the MD&A and the audited consolidated financial statements and related notes for the year ended December 31, 2009. This MD&A is dated August 10, 2010.

The financial data presented herein has in part been derived from the Company's annual audited consolidated financial statements prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP") and in accordance with accounting policies as set out in the Company's annual consolidated financial statements. The reporting currency is the Canadian dollar unless otherwise stated.

Additional information regarding Arsenal's financial and operating results may be obtained on the internet at www.sedar.com.

Forward-Looking Statements

Certain statements contained within the Management's Discussion and Analysis, and in certain documents incorporated by reference into this document, constitute forward looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward looking statements. Forward looking statements are often, but not always, identified by the use of words such as 'seek', 'anticipate', 'budget', 'plan', 'continue', 'estimate', 'expect', 'forecast', 'may', 'will', 'project', 'predict', 'potential', 'targeting', 'intend', 'could', 'might', 'should', 'believe' and similar expressions. These 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 statements.

In particular, this MD&A contains the following forward-looking statements pertaining to, without limitation, the following: Arsenal's production volumes and the timing of when additional production volumes will come on stream; Arsenal's realized price of commodities in relation to reference prices; future commodity prices; the Company's future royalty rates and the realization of royalty incentives; the impact of the New Royalty Framework on the Company's future royalties; Arsenal's expectation of reducing operating costs on a per unit basis; the relationship of Arsenal's interest expense and the Bank of Canada interest rates; increases in general and administrative expenses and recoveries; future development and exploration activities and the timing thereof; the future tax liability of the Company; the expected decrease in the depletion, depreciation and accretion rate; the estimated future contractual obligations of the Company and the amount expected to be incurred under its farm-in commitments; the future liquidity and financial capacity of the Company; and its ability to fund its working capital and forecasted capital expenditures. In addition, statements relating to 'reserves' or 'resources' are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future.

With respect to the forward-looking statements contained in the MD&A, Arsenal has made assumptions regarding: future commodity prices; the impact of royalty regimes and certain royalty incentives, the timing and the amount of capital expenditures; production of new and existing wells and the timing of new wells coming on-stream; future proved finding and development costs; future operating expenses including processing and gathering fees; the performance characteristics of oil and natural gas properties; the size of oil and natural gas reserves; the ability to raise capital and to continually add to reserves through exploration and development; the continued availability of capital, undeveloped land and skilled personnel; the ability to obtain equipment in a timely manner to carry out

exploration and development activities; the ability to obtain financing on acceptable terms; the ability to add production and reserves through exploration and development activities; and the continuation of the current tax and regulation.

We believe the expectations reflected in those forward looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward looking statements included in, or incorporated by reference into, this MD&A should not be unduly relied upon. These statements speak only as of the date of this MD&A or as of the date specified in the documents incorporated by reference into this Management's Discussion and Analysis, as the case may be. The actual results could differ materially from those anticipated in these forward looking statements as a result of the risk factors set forth below and elsewhere in this Management's Discussion and Analysis: volatility in market prices for oil and natural gas; counterparty credit risk; access to capital; changes or fluctuations in production levels; liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; stock market volatility and market valuation of Arsenal stock; geological, technical, drilling and processing problems; limitations on insurance; changes in environmental or legislation applicable to our operations, and our ability to comply with current and future environmental and other laws; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; and the other factors discussed under "Risk Factors" in the following annual MD&A. Readers are cautioned that the foregoing lists of factors are not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website. The forward looking statements contained in this MD&A and the documents incorporated by reference herein are expressly qualified by this cautionary statement. The forward-looking statements contained in this document speak only as of the date of this document and Arsenal does not assume any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable securities laws.

Boe Presentation

For the purpose of calculating unit costs, natural gas is converted to barrel of oil equivalent ("Boe" or "boe") using six thousand cubic feet ("Mcf") of natural gas to one barrel of oil unless otherwise stated. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of six Mcf to one barrel ("Bbl") is based on an energy equivalency method primarily at the burner tip and does not represent a value equivalency at the wellhead. (This conversion conforms to National Instrument 51-101). References to natural gas liquids ("NGLs") in this MD&A include condensate, propane, butane and ethane and one barrel of NGLs is considered to be equivalent to one barrel of crude oil equivalent (Boe).

Non-GAAP Measurements

Within the MD&A, references are made to terms having widespread use in the oil and gas industry in Canada. The measures discussed are widely accepted measures of performance and value within the industry, and are used by investors and analysts to compare and evaluate oil and gas exploration and producing entities. "Cash before non-cash working capital", "Funds from operations", "Funds from operations per share", "Netbacks" and "Netbacks per Boe" are not defined by GAAP in Canada and are regarded as non-GAAP measures. Funds from operations are determined by cash flow from operations before the change in non-cash operating working capital and asset retirement expenditures. Funds from operations should not be considered as an alternative to, or more meaningful than cash flow from operating activities as determined in accordance with GAAP as an indicator of the Company's performance. The Company's determination of funds from operations may not be comparable to that reported by other companies. Funds from operations per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of earnings per share.

Operating (or field) netbacks equal total revenue less royalties, operating costs and transportation, calculated on a commodity and Boe basis. Boe production per day is calculated by dividing total production for the period by the

number of days in the year or quarter as the case may be. Funds from operation netback is operating netback plus or minus gains or losses on commodity contracts less cash expenses for general and administrative, financing charges and other fees, interest on debentures and other expenses calculated on a Boe basis. Tables may not add due to rounding.

Funds from Operations

Funds from operations are not recognized by GAAP in Canada but it is used by analysts, bankers and others. The Company's lenders use funds from operations to measure debt to cash flow ratios that determine interest costs to the Company under its credit facility. Some 2009 amounts have been reclassified to conform to 2010 presentation.

The following table reconciles cash provided by operating activities to funds from operations which is used in the MD&A:

(\$Cdn.)	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	2010	2009	% Change
Cash provided by (used in) operating activities	(2,030,335)	3,996,635	(151)	3,394,375	10,974,620	(69)
Asset retirement obligations settled	394,940	101,322	290	628,552	354,464	77
Change in non-cash working capital	5,756,690	(2,066,235)	(379)	5,377,125	1,017,908	428
Funds from operations	4,121,295	2,031,722	103	9,400,052	12,346,992	(24)

Funds from operations netback for Q2 2010 totaled \$4.1 million or \$21.99 per Boe versus \$2.0 million or \$27.23 per Boe for Q1 2010 and \$9.98 per Boe for Q2 2009. A large portion of the comparative quarter decrease is related to production that declined 8% period over comparative period with a lesser portion attributed to higher operating expenses. The decrease was offset by an increase in the average price per Boe of 25% to \$59.37 per Boe. For the six month period ended June 30, 2010, funds from operations was \$9.4 million or \$24.65 per Boe versus \$12.3 million or \$29.88 per Boe in the 2009 comparative six month period. Average Boe prices increased in the 2010 six month period by 40% while production decreased 8%. The operations netback in the 2009 period includes \$9.1 or \$21.98 per Boe related to the monetization of commodity contracts.

2010 Financial and Operational Highlights

During Q1 2010, the Company completed a bought deal financing of 11.3 million common shares at \$0.85 per share and 3.0 million flow-through shares at \$1.00 per share for gross proceeds of \$12.6 million.

The Company's total debt (see Credit Facility) was reduced slightly during the current quarter to \$19.9 million at June 30, 2010 down from \$37.1 million at June 30, 2009 and \$28.7 million at December 31, 2009.

In Q2 2010, the 3 wells spud in Q1 2010 in North Dakota completed drilling. Two gross (0.49 net) wells at Stanley targeted the Bakken formation and one gross (0.16 net) well at Lindahl targeted the Three Forks formation. Two wells were completed using multi stage fractures and came on production during Q2 2010. The other well flowed and is expected to be frac'd in Q3 2010. In July, the Company spud one gross (0.125 net) partner operated second Three Forks well at Lindahl and has plans, subject to rig availability, to spud two gross (0.98 net) Company operated wells targeting the Bakken in Stanley.

Funds from operations for Q2 2010 totaled \$4.1 million or \$0.03 per share basic and diluted compared to \$5.3 million or \$0.04 per share basic and diluted in Q1 2010 and \$2.0 million or \$0.02 per share basic and diluted in Q2 2009. For the six month period, 2010 funds from operations totaled \$9.4 million or \$0.07 per share basic and diluted versus \$12.3 million or \$0.12 per share basic and diluted during 2009. The June 30, 2009 six month period included in funds from operations monetized commodity contracts totaling \$9.1 million.

Capital expenditures for Q2 2010 totaled \$2.4 million bringing the year to date capital expenditures for 2010 to \$11.0 million versus \$1.1 million for Q2 2009 and \$3.7 million for the six month 2009 period.

Arsenal's production for Q2 2010 averaged 2,060 Boe per day (82% crude oil and NGL's and 18% natural gas) versus a Q1 2010 average of 2,154 Boe per day (73% crude oil and NGL's and 27% natural gas) and a Q2 2009 average of 2,236 Boe per day (67% crude oil and NGL's and 33% natural gas). The percentage of crude oil production increased as result of Q1 2010 drilling in the US. Production declined in Q2 2010 versus Q1 2010 due to production declines, wet field conditions during the quarter, a facility turnaround and to the nature of the natural decline of the Company's production at Evi. Production from new drills in North Dakota was recorded for part of the quarter only.

Production for the 2010 six month period declined to average 2,107 Boe per day versus 2,283 Boe per day for the comparable 2009 six month period. Lower production was due to property sales, wet field conditions and natural production declines. No wells were drilled in Q2 2010.

In April 2010, the Company's bank increased the Company's Credit Facility from \$31.0 million to \$40.0 million.

On May 27, 2010, the Company announced its intention to make a normal course issuer bid ("NCIB") commencing May 31, 2010 and ending May 30, 2011. A total of 6,740,767 shares may be acquired under the bid. As of August 10, 2010, the Company has purchased 817,418 common shares under the bid.

Arsenal has 132,480,047 common shares and 12,804,500 stock options outstanding as of August 10, 2010. The Company's shares are listed and posted for trading on the Toronto Stock Exchange under the symbol "AEI" and on the Frankfurt Stock Exchange under the symbol "A1E".

The Company operates in the United States ("US") through its subsidiary; Arsenal Energy USA Inc. Production in the US averaged 681 Boe per day in Q2 2010 up from 482 in Q1 2010 and up from 440 Boe per day in Q2 2009. In Canada, the Company operates under Arsenal Energy Inc. Production in Canada averaged 1,379 Boe per day down from 1,672 Boe per day in Q1 2010 and down from 1,796 Boe per day in Q2 2009. The increase in the US relates to the added production from Bakken drilling in North Dakota that was completed in Q2 2010 with production commencing during Q2 2010 offset by natural declines and production adjustments. Canadian production declined in Q2 2010 due to property sales in 2009, natural declines, flush Evi production in Q1 2010 from recent drilling and due to an inactive capital program in Canada in Q2 2010.

OUTLOOK

Funds from operations in Q2 2010 increased to \$4.1 million, a 103% increase from \$2.0 million in Q2 2009. The Company has divested non-core low netback properties to focus on core properties in Canada and the US with a longer reserve life. Over the past eighteen months, the Company has dedicated an increasingly larger portion of its capital budget to development of its Stanley and Lindahl properties in North Dakota with the higher Company working interest wells still to be drilled.

The Bakken and Three Forks formations in these properties are developed utilizing horizontal drilling with ever improving multi stage fracturing technology. The wells produce light oil, are characterized by high initial production rates that decline rapidly (within six months) to approximately one third of the initial rate followed by a long low decline profile to recover (depending on the spacing unit and zone) between 500,000 and 750,000 barrels of light oil. Low operating costs result in high netbacks and very attractive economics. Future upside may included infill drilling (down spacing to 320 acres) to increase oil recovery.

In Q1 2010, the Company participated in the drilling of 3 gross (0.65 net) wells in North Dakota, being 2 gross (0.49 net) wells in Stanley targeting the Bakken formation and 1 gross (0.16 net) well in Lindahl targeting the Three Forks formation. Two of the wells were completed utilizing multi stage fracture technology and came on production during Q2 2010. The third well flowed during the quarter and is scheduled to be fracture stimulated in Q3 2010. The Company has spud a second well at Lindahl (0.125 net) targeting the Three Forks. Arsenal, subject to rig availability, hopes to spud the first of two (1.0 net) high working interest Company operated wells targeting the Bakken in Stanley in Q3 and to have the wells completed and on production in Q4 2010.

The \$12.6 million equity offering in February 2010 and the reduced Q2 2010 capital program provides the Company with a stronger balance sheet and increased financial flexibility. This financial strength and flexibility combined with the expected increase in production from the US wells drilled, and planned to be drilled, should allow the Company to undertake a higher, more aggressive, capital program in 2011.

Should future commodity prices, particularly for crude oil, remain near current levels, the Company expects to participate in drilling Bakken and Three Forks wells in North Dakota and to drill in Alberta at Evi, Princess and Wildmere to take advantage of the reduced royalty rates in the Province. Before year end, the Company hopes to participate in approximately 19 gross (12.1 net) wells of which two (1.0 net) are expected to be operated and drilled in North Dakota at Stanley targeting the Bakken. The Company's capital expenditure program for 2010 is planned to total from between \$30.0 and \$32.0 million of which \$11.0 million was expended in the first half of 2010. Total capital expenditures will, to some extent, depend on the number of Bakken and Three Forks wells drilled in North Dakota by Arsenal and its partners.

As a result of lower strip prices, non-core property sales and rig availability in North Dakota, the Company's original 2010 estimates have changed. Lower current strip prices and non-core property sales have reduced production and revenue estimates and the drilling, completion and on-stream estimated dates for North Dakota wells have been delayed. These factors have resulted in a lowering of the Company's 2010 guidance. The revised guidance is based on the assumption that Arsenal will secure, on a timely basis, a drilling rig and fracing services for its North Dakota drilling program.

Based on current strip prices and current plans, including the magnitude of capital expenditures, the expected timing of rigs, expected completions and on-stream dates, the Company is expected to average from between 2,100 and 2,200 Boe per day down from the earlier forecast of between 2,400 and 2,500 Boe per day for 2010. The exit rate for 2010 is estimated at approximately 2,750 Boe per day down from the earlier forecast of 3,000 Boe per day. Funds from operations for 2010 are estimated to be from between \$20.0 and \$21.0 million down from between \$26.0 and \$27.0 million originally estimated. Total debt at year end 2010 is estimated to be between \$25.0 and \$26.0 million unchanged from the prior forecast. The Company's 2010 budget utilizes the current 2010 WTI strip price of approximately \$77.50 US per barrel for oil, \$3.90 per mmbtu for natural gas and a Canadian/US exchange rate of \$0.97. Arsenal's current mix of oil (82%) and natural gas (18%) is expected increase over the year due to drilling activities and to generate revenue of approximately \$47.0 million (\$59.00 Cdn. per Boe) and an operating netback of approximately \$23.0 million (\$29.09 per Boe) for 2010 before overhead, interest any adjustments for commodity contracts.

FINANCIAL & OPERATING RESULTS

	Three Months Ended June 30		Six Months Ended June 30	
	2010	2009	2010	2009
FINANCIAL				
Petroleum and natural gas revenues	11,128,046	9,638,098	22,714,559	17,608,011
Funds from operations ¹	4,121,295	2,031,722	9,400,051	12,346,992
Pershare - basic and diluted	0.03	0.02	0.07	0.12
Net loss	(1,853,112)	(3,235,660)	(3,613,128)	(6,307,371)
Pershare - basic and diluted	(0.01)	(0.03)	(0.03)	(0.06)
Total debt (excluding derivatives)	19,886,286	37,104,499	19,886,286	37,104,499
Capital expenditures	2,405,406	1,139,845	11,039,356	3,714,906
Property dispositions	-	2,326,749	214,831	3,166,124
Wells drilled				
Oil	-	6.80	2.15	11.35
Gas	-	-	-	-
Dry	-	1.00	-	2.00
Shares outstanding - end of period	134,195,472	101,249,646	134,195,472	101,249,646
OPERATING				
Daily production				
Heavy oil (bbl/d)	646	737	646	815
Light oil and NGLs (bbl/d)	1,049	769	986	815
Natural gas (mcf/d)	2,189	4,386	2,849	3,916
Oil equivalent (boe @ 6:1) ²	2,060	2,236	2,107	2,283
Realized commodity prices (\$Cdn.)				
Heavy oil (bbl)	60.56	59.96	64.97	45.20
Light oil and NGLs (bbl)	70.44	60.07	71.30	53.56
Natural gas (mcf)	4.24	3.55	4.65	4.28
Oil equivalent (boe @ 6:1)	59.37	47.35	59.57	42.61
Reference pricing				
WTI Cushing, Oklahoma (\$U.S./bbl)	77.84	59.51	78.28	51.29
AECO (daily spot) (\$Cdn./mcf)	3.90	3.47	4.43	4.20
Foreign exchange (\$Cdn./\$U.S.)	0.97	0.86	0.97	0.83
Operating netback (\$ per boe)				
Revenue	59.37	47.35	59.57	42.61
Royalty	(11.32)	(8.80)	(10.03)	(8.69)
Operating expense	(20.88)	(16.62)	(19.94)	(17.03)
Transportation expense	(0.87)	(1.09)	(1.05)	(1.05)
Operating netback per boe	26.30	20.84	28.55	15.84

(1) "Funds from operations", "funds from operations per share", "netbacks" and "netbacks per boe" are not defined by Generally Accepted Accounting Principles ("GAAP") in Canada and are regarded as non-GAAP measures. Funds from operations and funds from operations per share are calculated as cash provided by operating activities before changes in non-cash working capital and asset retirement expenditures. Funds from operations is used to analyze the Company's operating performance, the ability of the business to generate the cash flow necessary to fund future growth through capital investment and to repay debt. Funds from operations does not have a standardized measure prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other companies. The Company also presents funds from operation per share whereby per share amounts are calculated using the weighted average number of common shares outstanding consistent with the calculation of net income or loss per share.

(2) The term barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet per barrel (6 mcf/bbl) of natural gas to barrels of oil equivalence is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in the report are derived from converting gas to oil in the ratio mix of six thousand cubic feet of gas to one barrel of oil.

PRODUCTION AND REVENUE

Average Daily Production

The Company produces in the provinces of British Columbia, Alberta and Saskatchewan in Canada (67% of total Q2 2010 production) and in the state of North Dakota in the US (33% of total Q2 2010 production). The percentage of production from Canada versus the US will fluctuate somewhat, depending on the timing of drilling and completions and the production rates from the drilling of US properties but is expected to increase over time as a percentage of total production as the Company continues to concentrate its drilling program on Bakken and Three Forks oil formations in North Dakota and as it disposes of non-core properties in Canada. Production from drilling in the Bakken and Three Forks formations is characterized by low operating costs and high initial production rates, followed by production declines within a few months, after which, production declines tend to level out.

Production for Q2 2010 averaged 2,060 Boe per day versus 2,154 Boe per day in Q1 2010 and 2,236 Boe per day in Q2 2009. Production from the Bakken and Three Forks wells drilled in 2010 increased production in the US while Evi wells drilled in Q4 2009 and Q1 2010 in Canada came off their initial high production rates and leveled out. Wet field conditions also affected Q2 2010 Canadian production and field operations. Production for the six month period ended June 30, 2010 averaged 2,107 Boe per day down from 2,283 Boe per day for the comparable period in 2009 due primarily to natural production declines and property sales during 2009.

Production of heavy oil has declined during the current quarter and current six month period when compared to their corresponding 2009 periods due to property sales and natural well declines.

Production of light oil and NGL's has increased during the current quarter and current six month period when compared to their corresponding 2009 periods as the Company has concentrated its drilling efforts and program on North Dakota light oil in the Bakken and Three Forks formations.

Production of natural gas declined during the current quarter and current six month period when compared to their corresponding 2009 periods due to no natural gas wells being drilled in 2009 or to date in 2010, to natural declines and to property sales. The Company has deemphasized natural gas drilling due to low prices and the opportunities and projects available for additional oil production. Over 2010, the percentage of production from natural gas should decline further.

Production Profile and Per Unit Prices

Production	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	2010	2009	% Change
Heavy oil (bbl/d)	646	737	(12)	646	815	(21)
Light oil and NGLs (bbl/d)	1,049	769	36	986	815	21
Natural gas (mcf/d)	2,189	4,386	(50)	2,849	3,916	(27)
Total (boe/d)	2,060	2,236	(8)	2,107	2,283	(8)

Production split

Heavy oil	31%	33%	(5)	31%	36%	(14)
Light oil and NGLs	51%	34%	48	47%	36%	31
Natural gas	18%	33%	(46)	22%	28%	(22)

Production Split - By Country

Canada	67%	80%	(16)	72%	80%	(9)
US	33%	20%	66	28%	20%	37

Production by Area

AREA	Three Months Ended June 30					Six Months Ended June 30			
	2010		2009		2010		2009		
	Boe/d	% of Total	Boe/d	% of Total	Boe/d	% of Total	Boe/d	% of Total	
Canada									
Maidstone (heavy oil)	-	-	151	8	87	4	182	10	
Galahad (light oil and solution gas)	118	6	317	17	204	10	212	12	
Wildmere (heavy oil)	71	3	127	7	115	5	126	7	
Chauvin/Ribstone	337	16	-	-	316	15	-	-	
West Current	62	3	-	-	133	6	-	-	
Evi (light oil)	261	12	354	19	149	7	278	15	
Others	531	23	582	30	821	39	632	35	
Total Canada	1,379	63	1,531	80	1,824	86	1,430	78	
US									
Stanley (light oil)	397	19	116	6	180	8	119	7	
Lindahl (light oil)	124	6	67	4	68	3	75	4	
Tioga (light oil)	43	2	46	2	47	2	40	2	
Others	186	8	149	8	164	7	159	9	
Total US	751	34	378	20	459	21	393	22	
Total boe/d production	2,130	97	1,909	100	2,283	107	1,823	100	

The Maidstone property was sold in 2009. The decrease in the Galahad production relates to wet field conditions and to a treater turnaround completed during the quarter. The Company added production from drilling in 2009 and Q1 2010 at Evi and from drilling in 2009 and Q1 2010 at Stanley and Lindahl. The other properties experienced normal production declines.

Revenue

Prices

(\$Cdn.)	Three Months Ended June 30			Six Months Ended June 30		
Prices - Before Commodity Contracts	2010	2009	% Change	2010	2009	% Change
Heavy oil (bbl)	6056	5996	1	6497	4520	44
Light oil and NGLs (bbl)	7044	6007	17	7130	5356	33
Natural gas (mcf)	424	355	20	465	428	9
Total (boe)	5937	4735	25	5957	4261	40

(\$Cdn.)	Three Months Ended June 30			Six Months Ended June 30		
Reference Pricing	2010	2009	% Change	2010	2009	% Change
WTI Cushing, Oklahoma (\$U.S./bbl)	77.84	59.51	31	78.28	51.29	53
Light Oil Edmonton Par 40 API (\$Cdn./bbl)	75.41	66.17	14	77.88	58.58	33
Hardisty Bow River 24.9 API (\$Cdn./bbl)	66.34	61.68	8	69.92	52.73	33
AECO (daily spot) (\$Cdn./mcf)	3.90	3.47	12	4.43	4.20	5
Foreign exchange (\$Cdn./\$U.S.)	0.97	0.86	13	0.97	0.83	17

The Company sells crude oil under 30-day evergreen contracts. Natural gas production is sold in the spot market. The commodity prices received by the Company are reflective of the movement in commodity prices over the comparative periods.

The Company received an average price per Boe during Q2 2010 of \$59.37 per Boe an increase of 25% from \$47.35 per Boe received in Q2 2009. During the six month period ended June 30, 2010, the Company received an average price of \$59.57 per Boe up \$42.61 received in the comparable 2009 period. Q1 2009 average per barrel prices for crude was the lowest for the year, steadily improving to current levels. Crude prices have exhibited a certain degree of stability and support with West Texas Intermediate ("WTI") at between \$70.00 and \$80.00 US per barrel.

Natural gas prices increased during Q1 2010 but thereafter have remained soft with AECO (daily spot) averaging \$3.90 per mmbtu in Q2 2010 versus \$5.40 per mmbtu in Q1 2010 and \$3.47 per mmbtu in Q2 2009.

Oil and Gas Revenue

(\$Cdn.)	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	2010	2009	% Change
Heavy oil	3,558,785	4,018,996	(11)	7,597,647	6,669,716	14
Light oil and NGLs	6,724,980	4,203,817	60	12,719,660	7,903,183	61
Natural gas	844,281	1,415,285	(40)	2,397,252	3,035,112	(21)
Oil and gas revenues	11,128,046	9,638,098	15	22,714,559	17,608,011	29
Gain (loss) on commodity contracts	1,396,726	(718,604)	294	2,067,208	(423,417)	588
Oil and gas revenue after commodity contracts	12,524,772	8,919,494	40	24,781,767	17,184,594	44
Per Boe before commodity contracts	59.37	47.35	25	59.57	42.61	40
Per Boe after commodity contracts	66.82	43.82	52	64.99	41.59	56

Oil and gas revenues for Q2 2010 increased 15% from Q2 2009 due to an increase of 25% in the average price received per Boe. This price increase offset an 8% decline in production and a 13% increase in the strength of the Canadian dollar. For the six month period in 2010, oil and gas revenues increased 29% due to a 40% increase in the average price received per Boe. Increased product prices offset an 8% production decline and a 17% increase in the strength of the Canadian dollar (as the Canadian dollar strengthens, US oil and gas revenues in Canadian dollars are reduced).

The Canadian dollar strengthened 13% during the current quarter versus Q2 2009 and 17% for the current six month period versus the prior comparative six month period. In spite of this strengthening of the Canadian dollar, oil and gas revenues generated from production in the US in Q2 2010 increased 30% to \$4.1 million from Q1 2010 and increased 94% from Q2 2009. For the six month period, US production revenues increased 94% in 2010 to total \$7.3 million up from \$3.7 million in 2009. Higher crude prices and higher production offset the stronger Canadian dollar.

Oil and gas revenues from Canadian production decreased 7% to \$7.0 million for the quarter and increased 11% to \$15.4 million for the six month period. Higher commodity prices were slightly offset by production declines and by 2009 property sales. Oil and gas revenues from US production increased 30% to \$4.1 million for the quarter and increased 11% to \$7.2 million for the six month period. Production from drilling commenced in Q1 2010 accounts for the increase.

In Q2 2010, the Company recorded a gain of \$1.4 million (\$7.45 per Boe) on its commodity contracts of which \$557,002 was realized in the current quarter. For the six month 2010 period, the Company has recorded a gain on its commodity contracts of \$2.1 million of which \$875,360 has been realized at June 30, 2010.

Over the six month 2010 period, the Canadian dollar strengthened closing at \$0.94 US, natural gas prices weakened and the price of crude fluctuated however the spot average monthly closing price did not consistently exceed the future price. These factors combined to generate hedging gains. The strengthening Canadian dollar reduced the value of the Company's crude commodity contracts whereas the weak crude prices and the weakening of the natural gas price increased the value of the Company's crude and natural gas contracts. The price the Company ultimately realizes on its commodity contracts fluctuates monthly with the movement in the price of WTI in Canadian dollars and the AECO gas price.

The Company has a policy of entering into commodity contracts to protect the metrics of significant acquisitions and to fix a portion of its funds from operations during periods when the balance sheet is highly leveraged or when there are significant capital expenditure budgeted.

The following table details the financial commodity contracts the Company has in-place as at June 30, 2010 and the fair value of those contracts recorded in the financial statements as at June 30, 2010.

Commodity Sold	Volume Sold	Remaining Term	Pricing \$	Fair Value \$
Natural Gas	1,000 GJ per day	July 1, 2010 - Dec 31, 2010	6.78 per GJ	497,989
Oil	100 bbl per day	July 1, 2010 - Apr 30, 2011	79.50 per bbl	(77,635)
Oil	200 bbl per day	July 1, 2010 - Dec 31, 2010	85.05 per bbl	139,025
Oil	300 bbl per day	July 1, 2010 - Dec 31, 2010	87.70 per bbl	354,342
Oil	100 bbl per day	Jan 1, 2011 - Dec 31, 2011	85.50 per bbl	38,193
Oil	100 bbl per day	Jan 1, 2011 - Dec 31, 2011	89.50 per bbl	182,207
Oil	100 bbl per day	May 1, 2011 - Dec 31, 2012	87.05 per bbl	61,105
				1,195,226

As of the date of this MD&A, the Company has added two financial commodity contracts selling 100 barrels of crude oil per day for the period January 1, 2011 to December 31, 2011 at \$88.00 Canadian per barrel and a financial commodity contract selling 100 barrels of crude oil per day for the period January 1, 2012 to December 31, 2012 at \$90.65 Canadian per barrel.

Royalties

(\$Cdn.)	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	2010	2009	% Change
Heavy oil	447,490	523,960	(15)	1,000,189	1,120,613	(11)
Light oil and NGLs	1,566,404	1,086,307	44	2,761,159	2,047,380	35
Natural gas	108,016	179,960	(40)	63,772	421,632	(85)
Total royalties	2,121,910	1,790,227	19	3,825,120	3,589,625	7
% of gross oil and gas revenue	19%	19%	3	17%	20%	(17)
Per boe	11.32	8.80	29	10.03	8.69	15

The Company's royalty rate for Q2 2010 averaged 19%, identical to the Q2 2009 rate. For the current six month period, the rate averaged 17% lower than the 20% average for the 2009 six month period. The reduced rate relates to adjustments for accruals in 2009, the reduced Alberta royalty rates and to clarification of the interests held by US leaseholders.

Royalty rates for 2010 are expected to average in the 18% - 22% range, the same as experienced over the comparative quarters of 2008 and 2009. The rate fluctuates due to the timing of royalty free and low royalty production, adjustments to the Company's gas cost allowance and to some degree commodity prices and production rates. Increases or decreases in the dollar value of royalties are commodity price related with higher commodity prices resulting in a higher dollar value and lower commodity prices resulting in a lower dollar value. Added production from the US will increase the corporate average royalty rate somewhat.

On a Boe basis, royalty rates increased to \$11.32 for Q2 2010 and to \$10.03 for the current six month period in line with the increase commodity prices over the respective periods. The increase in the per Boe rate is expected as a result of the higher percentage of total revenue from the US that generally has higher royalty rates than in Canada. As prices increase and royalty holiday periods expire and as higher royalty production is brought on-stream as is the case on our new US production, the rate per Boe is expected to increase.

In 2008, the Alberta government announced its New Royalty Framework and subsequent thereto a number of changes and revisions to the New Royalty Framework that took effect January 1, 2009 and a Transitional Royalty Plan. A Q1 2009 announcement by the Alberta government on a "three point incentive program" to encourage

additional drilling reduces royalty rates on new wells drilled to 5% (to a maximum 50,000 barrels of oil or 500,000 mcf of natural gas) for a period of one year and provides a credit of \$200.00 per meter drilled. In Q1 2010, as a result of the Alberta governments "Competitive Review" further changes were announced that take effect January 1, 2011 that make the current 5% royalty rate (subject to the maximum production limits) on the first year of production on new natural gas or conventional oil wells permanent, reduced the maximum royalty on conventional oil production from 50% to 40% and adjusted the maximum rate for conventional natural gas well at higher price levels from 50% to 36%. In addition, further review is to be done on royalty curves which determine rates at certain price levels.

The Company's royalty rate in Canada should decline slightly as a result new drilling and the Alberta government's announcement in 2008 of its New Royalty Framework and subsequently thereto in 2009 and 2010 a number of changes and revisions thereto but will be offset by slightly higher royalty rates on new production in the US.

Operating Expenses

(\$Cdn.)	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	2010	2009	% Change
Heavy oil	1,504,572	881,219	71	2,960,573	2,344,629	26
Light oil and NGLs	1,678,972	1,710,518	(2)	3,183,911	3,159,650	1
Natural gas	729,297	791,626	(8)	1,456,753	1,534,648	(5)
Total operating expenses	3,912,841	3,383,363	16	7,601,237	7,038,927	8
Per boe	20.88	16.62	26	19.94	17.03	17

Operating costs in Q2 2010 have increased 10% to \$20.88 per Boe from \$19.03 in Q1 2010 and from \$16.62 per Boe in Q2 2009. The increase relates to lower Q2 2010 average production, processing fees and thirteenth month adjustments (adjustments of estimated monthly costs to actual yearly costs that are made yearly by the facility operator) relating to prior years received in the quarter from a partner, down time due to facility turnaround and upgrades and due to wet field conditions during the current quarter.

For the first six months of 2010, operating costs increased 17% to \$19.94 per Boe from \$17.03 from the comparable 2009 period. This increase relates primarily to the 8% decrease in production over the comparable period, to some prior year processing adjustments and inclement (cold or wet) weather conditions during the period.

Transportation Expenses

(\$Cdn.)	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	2010	2009	% Change
Heavy oil	119,695	119,182	-	223,999	241,300	(7)
Light oil and NGLs	(15,548)	38,355	(141)	60,027	78,658	(24)
Natural gas	58,845	64,597	(9)	117,718	113,550	4
Total transportation expenses	162,992	222,134	(27)	401,744	433,508	(7)
Per boe	0.87	1.09	(20)	1.05	1.05	-

Transportation expenses reflect the cost of delivering production to the custody transfer point of the purchaser and are incurred in British Columbia, Alberta and Saskatchewan and include gathering, processing and transmission costs, gas service costs (firm and interruptible) and costs to truck clean oil. In Q2 2010, no transportation costs are recorded on the Company's US properties as the sale of commodities in the US occurs at the lease and therefore costs to transport, truck or gather products sold are for the account of the purchaser. Transportation costs during the quarter, decreased by 27% on a dollar basis and 20% on a Boe basis. In prior

periods, the Company was accruing fees to transport new non operated US production. This was reversed in Q2 2010 resulting in a current period reversal (credit).

Operating Netback

(\$Cdn.)	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	%Change	2010	2009	%Change
Heavy						
Revenue	60.56	59.96	1	64.97	45.20	44
Royal ty	7.61	7.82	(3)	8.55	7.59	13
Operating	25.60	13.15	95	25.32	15.89	59
Trans portati on	2.04	1.78	15	1.92	1.64	17
Netback per barrel	25.30	37.22	(32)	29.19	20.08	45
Light oil and NGL's						
Revenue	70.44	60.07	17	71.30	53.56	33
Royal ty	16.41	15.52	6	15.48	13.87	12
Operating	17.59	24.44	(28)	17.85	21.41	(17)
Trans portati on	(0.16)	0.55	(130)	0.34	0.53	(37)
Netback per barrel	36.61	19.56	87	37.64	17.74	112
Gas						
Revenue	4.24	3.55	20	4.65	4.28	9
Royal ty	0.54	0.45	20	0.12	0.59	(79)
Operating	3.66	1.98	85	2.82	2.16	30
Trans portati on	0.30	0.16	83	0.23	0.16	42
Netback per mcf	(0.26)	0.95	(127)	1.47	1.36	8
Boe						
Revenue	59.37	47.35	25	59.57	42.61	40
Royal ty	11.32	8.80	29	10.03	8.69	15
Operating	20.88	16.62	26	19.94	17.03	17
Trans portati on	0.87	1.09	(20)	1.05	1.05	-
Netback per Boe	26.30	20.84	26	28.55	15.84	80

Heavy oil operating expenses per barrel increased 95% to \$25.60 per barrel due to declining well production and cold and wet weather.

Light oil transportation expenses per barrel have decreased as a Q1 2010 accrual for US oil production was not required and reversed in Q2 2010.

Gas operating and transportation expenses per mcf increased as a result of recording adjustments related to prior years.

The operating netback per Boe (before commodity price contracts) for all products increased 26% in Q2 2010 due to a 25% increase in revenue and a 20% reduction in transportation expenses that offset a 29% per Boe increase in royalties and a 26% increase in operating costs. For the six month period ended June 30, 2010, revenue per Boe increased 40% over the prior year six month period while royalties increased 15% and operating costs increased 17%. The revenue increase offset increases in royalties and operating expenses increasing the current year six month operating netback by 80% to \$28.55 per Boe.

Realized hedging gains add \$2.97 per Boe to the current quarter operating netback and \$2.30 per Boe to the current six month operating netback.

General and Administrative Expenses

(\$Cdn.)	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	2010	2009	% Change
Gross expenditures	1,265,067	1,263,914	0	2,384,611	2,399,626	(1)
Overhead recovery	(124,388)	(103,797)	20	(334,790)	(197,843)	69
Capitalized overhead	(105,000)	(87,900)	19	(210,000)	(175,800)	19
Net general and administrative expense	1,035,679	1,072,217	(3)	1,839,821	2,025,983	(9)
Net general and administrative per boe	5.53	5.27	5	4.83	4.90	(2)

For Q2 2010, general and administrative expenditures on a gross basis were approximately equal to Q2 2009. On a net basis, general and administrative expenditures declined 3%. Higher overhead recovery and slightly higher capitalized overhead were factors in the reduced net expenditures.

On a Boe basis, quarter general and administrative costs were up 5% or \$0.26 per Boe to \$5.53 per Boe in Q2 2010 versus \$5.27 per Boe in Q2 2009 as a result of production for Q2 2010 being down 8% from Q2 2009.

For the six month period ended June 30, 2010, expenditures were comparable but overhead recovery and capitalized overhead increased thereby reducing net expenses by 9% to \$4.83 per Boe. Lower net costs, the result of higher overhead recovery and capitalized costs, more than offset lower Q1 2010 production thereby reducing the Boe number.

In Q2 2010, the Company incurred higher costs related to salaries and bonuses due to the number of employees increasing and to implementing the normal course issuer bid but experienced reduced consulting and legal fees and lower office occupancy costs due to the subletting of a portion of its office space.

Overhead recovery increased as overhead related to capital expenditures and operated wells increased over prior comparative periods.

The Company capitalizes overhead directly related to exploration and development activities. For Q2 2010, the Company's capitalized overhead, excluding stock based compensation, increased as a result of the higher salaries and bonus over the comparative quarter.

Finance Charges and Fees

(\$Cdn.)	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	2010	2009	% Change
Financing charges and fees	357,052	546,665	(35)	615,707	783,964	(21)
Per boe	1.90	2.69	(29)	1.61	1.90	(15)

Financing charges include interest, bank charges and fees and other charges paid on the Company's credit facility, interest paid on the Company's unspent flow-through share obligation and other government and vendor charges.

Financing charges and fees decreased 35% in Q2 2010 from Q2 2009 and by 21% for the current six month period versus the comparative 2009 six month period. This reduction relates to lower average borrowings during the periods and to lower year over year fees offset by slightly higher interest rates. The Company maintained a lower average borrowing balance in the current quarter (\$18.8 million) and for the current six month period (\$18.9 million) when compared to the comparative second quarter (\$34.9 million) and to the comparative six month period (\$37.7 million) in 2009. This reduction was offset by higher interest rates paid by the Company. Credit facility fees paid in Q2 2010 totaled \$107,000 versus \$335,000 in the prior comparative quarter. The reduction in prime rates over the past year has been offset by increases in the spread charged to the Company by its lending institution resulting in slightly higher interest rates.

Interest on the Company's current credit facility is at rates ranging from Canadian or US prime plus 1.25% to 2.25% on prime based loans and from the base rate plus 2.75% to 3.75% on guaranteed notes and on Libor based loans. The interest rate is set based on the Company's debt, as calculated for this purpose to include bank debt plus working capital and excludes asset retirement obligations and risk management contracts (whether an asset or an obligation) and the income taxes related thereto, to trailing funds flow ratio (funds flow for the last quarter annualized).

During Q1 2010, the Company had a non-revolving reducing term loan facility of \$1.6 million with interest at Canadian or US prime plus 3.00% on prime based loans and from the base rate plus 4.50% on guaranteed notes and Libor based loans. The term loan was repaid January 29, 2010

Other Expense

(\$Cdn.)	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	2010	2009	% Change
Other expense	-	590,000	-	-	590,000	-
Per boe	-	2.90	-	-	1.43	-

Other expense in Q2 2009 represents an assessment by Canada Revenue Agency of a tax return for a company acquired by Arsenal and relates to a period prior to the acquisition of the company by Arsenal.

Interest on Convertible Debentures

(\$Cdn.)	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	2010	2009	% Change
Interest on debentures	-	-	-	-	34,323	-
Per boe	-	-	-	-	0.08	-

The Company paid interest semi-annually on June 30 and December 31 at 8% per annum on the \$3,480,000 of convertible debentures acquired in a corporate acquisition. The debentures were redeemed on February 15, 2009.

In Q1 2009, the Company paid \$34,323 of interest on the debentures and recorded \$16,911 of accretion expense relating to the amortization of the discount on the debentures.

Depletion, Depreciation and Accretion Expense

(\$Cdn.)	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	2010	2009	% Change
Depletion, depreciation and accretion	6,899,560	6,741,852	2	14,762,562	13,325,100	11
Per boe	36.81	33.12	11	38.72	32.25	20

Despite a decrease of 8% in production quarter over comparative quarter, depletion, depreciation and accretion for Q2 2010 increased 2% on a dollar basis and 11% on a Boe basis over Q2 2009. On a Boe basis depletion, depreciation and accretion increased to \$36.81 per Boe in Q2 2010 from \$33.12 per Boe in Q2 2009. This increase relates primarily to the Canadian cost centre and results from the sale during 2009 of properties with a low depletion and depreciation rate, a negative 2009 year end proven reserve adjustment in British Columbia and to a lesser degree, to an increase in the US cost centre of estimated future development costs required to develop proven reserves.

In Q2 2010, depletion and depreciation totaled \$35.25 per Boe versus a Q1 2010, rate of \$39.11 per Boe. The decrease from Q1 to Q2 2010 stems from higher US production that carries a lower depletion and depreciation

rate. The depletion and depreciation rate for Q2 2010 in Canada is \$47.54 per Boe (Q1 2010 - \$47.20 per Boe) and in the US is \$10.31 per Boe (Q1 2010 - \$10.15 per Boe).

Accretion is the increase for the reporting period in the present value of the Company's asset retirement obligation, which is discounted using an interest factor of 8%. Accretion increased slightly for the six month period in 2010 to \$1.48 per Boe from \$1.46 per Boe due to the increase in the Company's estimated liability at December 31, 2009.

Stock-based Compensation

	2010	2009	% Change	2010	2009	% Change
Stock-based Compensation expense	162,854	273,634	(40)	279,273	538,559	(48)

The Company accounts for its stock-based compensation program using the fair-value method. Under this method, compensation expense related to this program is recorded in the statement of operations over the vesting period of the options.

During the six month period ended June 30, 2010, the Company granted 4,140,000 options (Q2 2010 – 3,700,000 options) at a weighted average price of \$0.88 per share to employees. These options vest annually over three years and expire five years from date of grant. In addition, during the six month period ended June 30, 2010, 96,500 options (Q2 2010, 68,000 options) were exercised at a weighted average price of \$0.49 per share and 561,000 (Q2 2010 561,000) options at a weighted average price of \$1.16 per share were cancelled or expired unexercised.

Stock-based compensation expense for Q2 2010 decreased 40% from Q2 2009 and increase 40% from Q1 2010. For the 2010 six month period, stock-based compensation decreased 48% over that recorded in Q2 2009. Increases and decreases during the various reporting periods result from the timing of issue, valuation and vesting of options issued in 2008, 2009 and during 2010.

During Q2 2010 the Company capitalized to property plant and equipment \$23,021 (Q1 2010 - \$21,076) bringing the current six month period total to \$44,097 of stock based compensation representing stock based compensation relating to exploration overhead capitalized.

Future Income Tax

For the quarter ended June 30, 2010, the Company recorded a net future income tax reduction of \$849,681. The net future income tax reduction consists of a future income tax provision relating to the US operations of \$819,457 and a future income tax reduction of \$1,669,138 relating to Canadian operations. High depletion and depreciation charges in Canada for the quarter were primarily responsible for the loss before income taxes and the resultant reduction of future income taxes.

At June 30, 2010, \$309,583 has been recorded as a current future income tax liability and relates to the current portion of the unrealized risk management contract recorded in the financial statements. A future income tax liability of \$7,783,779 has been recorded as at June 30, 2010 relatively unchanged from \$7,860,589 recorded at December 31, 2009.

Arsenal does not expect to pay current tax in Canada or the US in 2010 or 2011 based on current commodity price forecasts and expected capital expenditures. The availability and deductibility of existing tax pools will offset income from oil and gas operations, and any realized commodity contract gains.

Cash and Funds from Operations and Net Loss

(\$Cdn.)	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	Change	2010	2009	Change
Cash provided by operating activities before changes in non-cash working capital	3,726,355	1,930,400	93	8,771,500	11,992,528	(27)
Funds from operations	4,121,295	2,031,722	103	9,400,052	12,346,992	(24)
Per share						
Basic	0.03	0.02	52	0.07	0.12	(41)
Diluted	0.03	0.02	52	0.07	0.12	(41)
Net loss	(1,853,112)	(3,235,660)	43	(3,613,128)	(6,307,371)	43
Per share						
Basic	(0.01)	(0.03)	57	(0.03)	(0.06)	56
Diluted	(0.01)	(0.03)	57	(0.03)	(0.06)	56

Funds from operations for Q2 2010 were \$4.1 million (\$0.03 per share basic and diluted) up 103% from \$2.0 million (\$0.02 per share basic and diluted) for Q2 2009. The increase relates to higher prices that increased 25% on a Boe basis. On a year to date basis funds from operations were down 24% to \$9.4 million (\$0.07 per share basic and diluted) for the six month ended June 30, 2010 from \$12.3 million (\$0.12 per share basic and diluted) for June 30, 2009. The June 30, 2009 period included \$9.1 million on monetized commodity contracts.

The reduction in the net loss for Q2 2010 of \$1.9 million (\$0.01 per share basic and diluted) from a loss of \$3.2 million (\$0.03 per share basic and diluted) in Q2 2009 was primarily the result of higher prices offset by slightly higher operating expenses, no current period "Other expenses" and a lower income tax reduction due to the recording of a provision in the US and reduced tax rates in Canada on the loss recorded.

For the six months ended June 30, 2010, the Company recorded a loss of \$3.6 million (\$0.03 per share basic and diluted) versus a loss of \$6.3 million (\$0.06 per share basic and diluted) in the comparable 2009 six month period. Although production was down 8%, average prices per Boe were up 40% in 2010 resulting in a 29% increase in revenues and there were no "other expenses" recorded in the current six month period versus \$590,000 incurred in the comparative period. In addition, the future income tax recovery recorded currently was lower than in the prior comparative period due to lower tax rates in Canada.

Comprehensive Loss

The Company's comprehensive loss includes unrealized foreign exchange gains and losses resulting from the translation into Canadian dollars of the Company's US subsidiary. For 2010, net loss was decreased for translation gains on foreign operations by \$150,626 for Q2 2010 (loss of \$348,948 for Q2 2009) and increased by \$2,374 for the current six month period (loss of \$348,948 six month 2009 due to date of adoption). Comprehensive loss therefore for Q2 2010 totaled \$1.7 million versus \$3.6 million for Q2 2009 and for the current six month period ended June 30, 2010 totaled \$3.6 million versus \$6.7 million for the 2009 six month period.

Summary of Quarterly Results

(\$Cdn.)	2010		2009				2008	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Oil and gas revenue	11,128,046	11,586,513	11,043,957	9,252,597	9,638,098	7,969,913	10,724,915	15,766,815
Net income (loss)	(1,853,112)	(1,760,016)	(2,845,384)	(1,897,761)	(3,235,660)	(3,071,711)	6,974,803	10,028,193
Per share - basic	(0.01)	(0.01)	(0.03)	(0.02)	(0.03)	(0.03)	0.08	0.11
Per share - diluted	(0.01)	(0.01)	(0.03)	(0.02)	(0.03)	(0.03)	0.08	0.11
Funds from operations	4,121,295	5,278,757	3,471,910	2,887,826	2,031,722	10,315,270	11,316,461	8,093,159
Per share - basic	0.03	0.04	0.03	0.03	0.02	0.10	0.13	0.09
Per share - diluted	0.03	0.04	0.03	0.03	0.02	0.10	0.13	0.09
Total assets	115,025,590	119,087,098	116,880,416	118,244,383	122,486,146	131,477,316	143,723,628	78,546,339
Total debt (1)	19,886,286	20,318,893	28,739,421	33,285,548	37,104,499	40,124,195	48,479,097	13,384,766
Shares outstanding	134,195,472	134,773,390	120,461,890	109,961,890	101,249,646	101,249,646	101,249,646	90,786,148

(1) Includes working capital and convertible debentures outstanding but excludes risk management contracts and future income taxes whether current or long term assets or liabilities.

Arsenal's quarterly results have fluctuated significantly in the past eight quarters due to a variety of factor including the GEOCAN acquisition, commodity price swings and the rationalization of properties. Arsenal has been and expects to continue to rationalize its asset base focusing on properties with high netbacks where the Company has a strategic, technical or financial advantage. Quarterly results therefore will continue to fluctuate somewhat and will depend on property dispositions, the movement in commodity prices particularly for oil, the differentials in heavy oil and the timing of drilling programs in North Dakota and Canada. With the establishment and maintenance of a core property base coupled with the continuing implementation of operational efficiencies, a more stable commodity market and continued drilling success in North Dakota, the Company expects its established production base to increase steadily and to lead to more comparative and stable results going forward.

Contractual Obligations

In the ordinary course of business, the Company enters into various contractual obligations, including the following:

- purchase of services
- royalty agreements
- operating agreements
- processing and treating agreements
- right-of-way and road use agreements
- lease obligations for office space and equipment
- flow-through share agreements

All such contractual obligations reflect market conditions at the time of contract and do not involve related parties. Obligations at June 30, 2010 with a fixed term are as follows:

(\$Cdn.)	2010	2011	2012	2013	2014
Flow-through share commitments	700,000	3,000,000	-	-	-
Lease of office premises	247,376	494,752	288,605	-	-
Equipment lease	8,675	-	-	-	-
Total	956,051	3,494,752	288,605	-	-

Based on current plans and projects, the Company is confident it will meet its flow-through share commitments as required under the various flow-through share arrangements.

The Company entered into a sublease with a subtenant for a term that commenced February 1, 2010 and ends on July 30, 2012. The sublease has reduced the Company's total commitment under its head lease by \$88,412 for the remainder of 2010, \$168,824 for 2011 and \$98,481 for 2012.

The Company has no off balance sheet arrangements.

Select Financial Information by Country

2010 (\$ Cdn.)	Canada	U.S	Total
Oil and gas revenue	15,448,102	7,266,457	22,714,559
Net income (loss) for the period	(5,004,945)	1,391,817	(3,613,128)
Operating income	6,989,766	3,896,692	10,886,458
Property, plant and equipment	92,321,376	12,703,498	105,024,874
Capital expenditures	8,041,612	2,997,744	11,039,356

2009 (\$ Cdn.)	Canada	U.S	Total
Oil and gas revenue	13,869,115	3,738,896	17,608,011
Net income (loss) for the period	(7,526,968)	1,219,597	(6,307,371)
Operating income	5,481,861	1,064,090	6,545,951
Property, plant and equipment	104,960,294	8,466,099	113,426,393
Capital expenditures	1,649,688	2,065,218	3,714,906

Segmented Statement of Operations By Country

Six Months Ended June 30, 2010

(\$Cdn.)	Canada	United States	Total Company
Revenue			
Oil and gas	15,448,102	7,266,457	22,714,559
Gain (loss) on risk management contracts	1,746,712	320,496	2,067,208
Royalties	(2,030,041)	(1,795,079)	(3,825,120)
	15,164,773	5,791,874	20,956,647
Other income	3,793	755	4,548
	15,168,566	5,792,629	20,961,195
Expenses			
Operating	5,923,713	1,677,524	7,601,237
Transportation	504,582	(102,838)	401,744
General and administrative	1,169,466	670,355	1,839,821
Finance charges and fees	476,482	139,225	615,707
Foreign exchange gain	(76,340)	-	(76,340)
Depletion, depreciation, and accretion	13,565,473	1,197,089	14,762,562
Stock-based compensation	279,273	-	279,273
	21,842,649	3,581,355	25,424,004
Income (loss) before income taxes	(6,674,083)	2,211,274	(4,462,809)
Future income tax (reduction)	(1,669,138)	819,457	(849,681)
Net income (loss)	(5,004,945)	1,391,817	(3,613,128)

As the Company focuses its capital program on drilling Bakken and Three Forks oil prospects in North Dakota, it is expected that the US operations will generate a more significant portion of the Company's production, revenues and profits.

Bank Loan, Liquidity and Capital Resources

Capital Management

In order to continue the Company's ongoing exploration and development program, the Company must maintain a strong capital base. A strong capital base results in increased market confidence, an essential factor in maintaining existing shareholders and in attracting new investors. The Company is committed to establishing and maintaining a strong capital base to ensure the Company has access to the equity and debt markets when deemed advisable. In order to maintain a strong capital base, the Company continually monitors the risk reward profile of its exploration and development projects and the economic indicators in the market including commodity prices, interest rates and foreign exchange rates. It then determines increases or decreases to its capital budget.

The Company considers shareholder's equity, bank debt and working capital as components of its capital base. The Company can access or increase its capital base through the issuance of shares and through bank borrowings that are based on reserves. The Company can safeguard its capital base by stabilizing its funds from operations, by fixing commodity prices on a portion of the Company's production by closely monitoring expenses and by closely monitoring and scrutinizing the results of its capital expenditure program and adjusting capital expenditures as required based on economic conditions and drilling results.

The Company monitors its capital base based primarily on its debt to annualized funds flow ratio and its debt to equity ratios. Debt includes bank borrowings, plus or minus working capital. Annualized funds flow is calculated as cash flow from operations before changes in non-cash working capital and asset retirement expenditures from the Company's most recent quarter multiplied by four adjusted, if required, by increasing or decreasing commodity price expectations, future production profiles and other non-recurring items. The Company's goal is to target this ratio at 1 : 1 but the ratio can and will fluctuate based on the timing of property transactions, commodity prices and on the mix of exploratory and development drilling. During periods of extreme commodity price declines, high drilling activity or after large property or corporate acquisitions, it is expected that the ratio would increase and during periods of high commodity prices and low activity levels, it is expected that the ratio would decrease. The Company's focus in these instances is to concentrate on bringing the ratio back into the target range. The Company prepares an annual operating and capital expenditure budget. The budget is updated when critical factors change and when actual results are realized and compared to budget. Critical factors include economic factors such as the state of equity markets, changes to commodity prices, interest rates and foreign exchange rates and non economic factors such as drilling results and production profiles. The Company's board of directors approves the budget and reviews changes thereto. The Company has targeted a debt to equity ratio of 0.5 : 1. This ratio will also fluctuate over time depending on the state of equity markets and the results of operations.

At June 30, 2010, the Company's debt to annualized funds flow ratio was 1.21 : 1 and its debt to equity ratio was 0.31 : 1. An equity issue generating net proceeds of approximately \$11.6 million in February 2010 reduced debt thereby improving the debt to annualized funds flow ratio and the debt to equity ratio. The debt to forward funds from operations ratio at June 30, 2010 is 1.21 : 1, within reach of the target range of the corporate goal of 1 : 1 as established in the management strategy goals and guidelines.

	June 30, 2010
Bank loan	\$ 19,823,000
Working capital <i>(excluding risk management contracts and future income taxes)</i>	<u>63,286</u>
Total debt	19,886,286
Annualized funds flow	\$ 16,485,180
Net debt to annualized funds flow ratio	<u>1.21</u>

The Company expects to focus the greater part of its remaining capital budget in the US in North Dakota on Bakken drilling at Stanley and on Three Forks drilling at Lindahl and in Canada at Princess and Evi, both in Alberta

Key factors that will determine if the Company will be able to maintain within its established guidelines are production rates from expected drilling, commodity (particularly crude) prices and the magnitude and timing of capital requirements to drill wells in the Bakken and Three Forks plays in North Dakota. The Company is continuing with its commodity risk management program to lock in a portion of future funds from operations and maintains a portion of its debt in US dollars as a hedge against the foreign exchange fluctuations affecting certain elements of its business. During the current quarter, the Company reduced its US dollar borrowings from \$10.0 million to \$5.0 million due to its lower overall debt level and due to the appreciation of the Canadian dollar versus the US dollar (this results in reduced equivalent Canadian borrowings).

The Company's share capital is not subject to external restrictions.

There were no changes in the Company's approach to capital management during the period.

Credit Facility

In April 2010, based on the bank's review of the Company's December 31, 2009 engineering report, the Company's credit facility was increased from \$31.0 million to \$40.0 million. The credit facility can be utilized in either Canadian or US dollars. Interest on the Company's credit facility is at rates ranging from Canadian or US prime plus 1.25% to 2.25% on prime based loans and from the base rate plus 2.75% to 3.75% on guaranteed notes and on Libor based loans. The interest rate is set based on the Company's debt, as calculated for this purpose to include bank debt plus working capital and excludes asset retirement obligations and risk management contracts (whether an asset or an obligation) and the income taxes related thereto, to trailing funds flow ratio (funds flow for the last quarter annualized).

The credit facility is secured by a fixed and floating charge debenture providing a fixed charge over all present and after acquired petroleum and natural gas interests and a floating charge over all lands, a limited liability guarantee from the Company's US subsidiary in the form of a Mortgage Security Agreement, Financing Statement and Assignment and Letter of Undertaking in the amount of \$20,400,000. Under the credit facility, the Company is able to sell or dispose of assets or property having a fair aggregate value not exceeding 10% of the borrowing base with no adjustment to the borrowing base.

At June 30, 2010, debt under the facility amounted to \$19.9 million. Included in debt under the facility is US \$5,000,000 (CAD - \$5,323,000) Libor based loan. At December 31, 2009, the Company had a non-revolving reducing term loan facility in the amount of \$4.08 million requiring reductions of \$820,000 per month. The non-revolving term facility was repaid in its entirety January 29, 2010.

The Company's credit facility has a financial covenant that, without the written consent of the lender, would result in a breach of the agreement. The Company cannot permit:

the working capital ratio (as defined in the agreement to include the unutilized portion of the facility) to fall to below 1 : 1.

At June 30, 2010, the Company is in compliance with this covenant.

The next annual review date has been set for May 31, 2011 but may be set earlier or later date at the sole discretion of the lender.

Liquidity

During the early part of 2009, commodity prices were low and due to the unpredictable timetable of the economic recovery, unstable. In addition, there was limited access to equity markets. As a result of this environment and the Company's high debt (due to the GEOCAN acquisition), management's approach and operating strategy during most of 2009 was guarded. The Company was focused on weathering the economic storm, reducing operating

costs and capital expenditures (except expenditures on the Company's Bakken and Three Forks plays in North Dakota), the sale of non-core properties and paying down its debt.

With the apparent economic recovery in late 2009 and 2010, crude prices improved and stabilized and access to equity markets is better. Increased commodity prices have led to an improvement in the Company's funds from operations and its access to capital. In late 2009, the Company completed two equity issues generating gross proceeds of \$9.0 million. In Q1 2010, the Company completed another equity issue for gross proceeds of \$12.6 million and in Q2 2010 had its credit facility increased to \$40.0 million. The Company has the financial resources necessary to undertake a 2010 capital program that approximates its 2010 funds from operations and remain within an acceptable level of debt and within its targeted range of its debt to annualized funds flow from operations ratio. In the event that commodity prices, interest or exchange rates, or other factors negatively impact funds flow from operations, the Company anticipates that it will reduce the remaining 2010 capital program to safeguard its capital base and to ensure that debt stays not only within the Company's credit facility but also within its targeted debt to forward annualized funds flow from operations.

In order to further ensure that funds are available to assist in the financing of the Company's 2010 capital program, the Company has in place certain commodity hedges. At June 30, 2010 the Company had the following commodity contracts in place:

Commodity Sold	Volume Sold	Remaining Term	Pricing \$	Fair Value \$
Natural Gas	1,000 GJ per day	July 1, 2010 - Dec 31, 2010	6.78 per GJ	497,989
Oil	100 bbl per day	July 1, 2010 - Apr 30, 2011	79.50 per bbl	(77,635)
Oil	200 bbl per day	July 1, 2010 - Dec 31, 2010	85.05 per bbl	139,025
Oil	300 bbl per day	July 1, 2010 - Dec 31, 2010	87.70 per bbl	354,342
Oil	100 bbl per day	Jan 1, 2011 - Dec 31, 2011	85.50 per bbl	38,193
Oil	100 bbl per day	Jan 1, 2011 - Dec 31, 2011	89.50 per bbl	182,207
Oil	100 bbl per day	May 1, 2011 - Dec 31, 2012	87.05 per bbl	61,105
				1,195,226

Commodity contracts may be monetized or additional commodity contracts may be put in place, depending on changes in commodity prices and the expected level of the Company's capital expenditure program, production and cash flow and the Company's financial position.

Share Capital

In February 2010, the Company issued 11,283,000 common shares at \$0.85 per share and 3,000,000 flow-through shares at \$1.00 per share for gross proceeds of \$12,590,550.

In May 2010, the Company announced it had received approval for a normal course issuer bid ("NCIB") commencing May 31, 2010 and ending May 30, 2011. A total of 6,740,767 common shares may be acquired under the bid representing 5% of the 134,815,340 common shares outstanding as of May 20, 2010. As at June 30, 2010, the Company had acquired 645,918 common shares under the bid at an average price of approximately \$0.84 per share plus acquisition costs.

During the six month period ended June 30, 2010, 4,140,000 stock options at a weighted average price of \$0.88 per share were issued, 96,500 options at a weighted average exercise price of \$0.49 were exercised for proceeds of \$47,650 and 561,000 options at a weighted average price of \$1.16 per share were forfeited or expired unexercised.

At June 30, 2010, the Company has 134,195,472 common shares and 12,804,500 options at a weighted average price of \$0.63 outstanding.

As of the date of this MD&A, the Company has 132,480,047 common shares and 12,804,500 options outstanding. The Company purchased 171,500 additional common shares under its NCIB since June 30, 2010.

Common shares	Six Months Ended June 30		Year Ended December 31	
	Shares	2010 Amount (\$)	Shares	2009 Amount (\$)
Balance - beginning of period	120,461,890	100,955,986	101,249,646	93,515,925
Tax effect of flow-through shares	-	(1,250,000)	-	(1,040,000)
Issued on exercise of options	96,500	47,650	-	-
Allocated from contributed surplus	-	40,666	-	-
Issue of common shares	11,283,000	9,590,550	8,000,000	4,000,000
Issue of flow-through shares	3,000,000	3,000,000	11,250,000	5,000,000
Share issue costs	-	(1,033,910)	-	(665,580)
Tax effect of share issue costs	-	261,827	-	180,125
Unclaimed share returned to treasury	-	-	(37,756)	(34,484)
Purchases under normal course issuer bid	(645,918)	(534,182)	-	-
Balance - end of period	134,195,472	111,078,587	120,461,890	100,955,986

In March 2009, the board of directors adopted a shareholder rights plan which is designed to ensure fair treatment of the Company's shareholders by providing shareholders more time than is afforded under existing Canadian legislation to properly evaluate any unsolicited takeover bid and to seek possible alternatives to maximize value for all shareholders. The Company is not aware of any pending or contemplated takeover bids.

Related Party Transactions

An officer of the Company is a partner in a law firm that provides legal services to the Company. During the six month period ended June 30, 2010, the Company recorded a total of \$132,812 (June 30, 2009 - \$44,783) for legal fees and disbursements.

All related party transactions have been recorded at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Capital Expenditures

(\$ Cdn.)	Three Months	Three Months	Year to Date	Year to Date
	Ended June 30 2010	Ended March 31 2010	2010	2009
Land	294,937	2,303,886	2,598,823	293,302
Seismic	39,018	1,449,067	1,488,085	108,287
Drilling and completions	1,513,233	2,831,150	4,344,383	2,564,277
Capitalized general and administrative	105,000	105,000	210,000	175,800
Production equipment, facilities and tie-ins	401,425	1,944,847	2,346,272	568,840
Other	87,036	28,558	115,594	153,911
Total property plant and equipment additions	2,440,649	8,662,508	11,103,157	3,864,417
Non-cash additions	(35,243)	(28,558)	(63,801)	(149,511)
Capital expenditures	2,405,406	8,633,950	11,039,356	3,714,906
Property dispositions	-	214,831	214,831	(3,166,124)

Capital expenditures for Q2 2010 totaled \$2.4 million or 111% higher than \$1.1 million expended in Q2 2009. For the current six month period ended June 30, 2010, the Company spent \$11.0 million on capital of which \$6.7 million was spend on drilling, completions and production facilities and \$4.1 million was expended on land and seismic. During the current six month period, \$3.0 million was expended in the US to drill three wells in North Dakota and to complete and equip two of these wells (the third well is waiting on completion equipment). The Company spent \$8.0 million in Canada to drill and complete three gross (1.5 net) wells at Evi, to acquire land and seismic and to tie in production at Galahad.

After quarter end, the Company reached an agreement to sell its noncore low netback NE BC natural gas property for gross proceeds of \$2.7 million. Production from the property is less than 100 Boe per day. In addition to proceeds received on the sale of the property, the Company will reduce its asset retirement obligations on the property.

Asset Retirement Obligation

The Company's asset retirement obligation represents the present value of estimated future costs to be incurred to abandon and reclaim the Company's wells and facilities. Increases in the obligation year over year result from the obligations arising from drilling activities, acquisitions, increases in estimated costs or changes to timing to abandon and reclaim wells and from the quarterly increase in the present value of the obligation (accretion). Decreases in the obligation year over year result from property dispositions, decreases in estimated costs or changes to timing to abandon and reclaim wells and costs incurred in settlement of abandonment obligations. At June 30, 2010, the Company has recorded an asset retirement obligation of \$13,871,993 (December 31, 2009 - \$14,044,639).

Commitments and Contingencies

Outstanding lawsuits

Various lawsuits have been filed against the Company for incidents which arose in the ordinary course of business. In the opinion of management and legal counsel, the outcome of the lawsuits, now pending, is not material to the Company's operations. Should any loss result from the resolution of these claims, such loss will be charged to operations in the period of resolution.

Risk Factors

Arsenal is subject to multiple business risks that are similar to other entities involved in the conventional energy sector. Arsenal's financial position, results of operations and funds from operations are directly impacted by the following factors:

Commodity price risk

Commodity price risk is defined as fluctuations in crude oil, natural gas, and natural gas liquid prices. The Company uses derivative instruments as part of its risk management approach to manage commodity price fluctuations and stabilize funds from operations available for future development programs. The Company does not enter into derivative contracts for speculative purposes. During 2008, the Company entered into four crude oil derivative contracts and one natural gas derivative contract. These contracts were monetized during late 2008 and Q1 2009. In 2009, the Company entered into additional derivative contract covering various periods in 2009 and 2010 for both oil and natural gas. At June 30, 2010, the Company had in place six crude oil derivative contracts covering 2010, 2011 and 2012 and one natural gas derivative contract for 2010 (see Liquidity section of this MD&A).

See "Liquidity" for the Company's current commodity contracts.

Production risk

Production risk relates to the Company's ability to produce, process and transport crude oil and natural gas. To manage this risk to an acceptable level, the Company performs regular and proactive maintenance on its wells, facilities and pipelines. The Company operates approximately 80% of its production, which affords greater control over operations. Approximately 33% of the Company's Q2 2010 (20% of Q1 2010) production is in the United States.

Natural Decline and Reserve Replacement Risk

Natural decline risk relates to the Company's ability to replace reserves in excess of annual production declines through development activities such as drilling, well completions, well workovers and other capital activities. The Company manages its business using a portfolio approach whereby capital is allocated across a number of areas so that significant capital is not risked on any one activity. Capital is spent only after strict economic criteria for production and reserve additions are assessed.

The Company's reserves are evaluated on an annual basis by independent third-party consultants reporting to the Company's Reserves Committee of the Board of Directors. The Company's approach is to invest in mature, long-life properties with a high proved producing component combined with low-risk development opportunities where the reserve risk is generally lower and cash flows are more stable and predictable. The Company will engage in wildcat exploration activities only after considerable due diligence has been completed on the play, including geological, geophysical and total capital required.

Environmental Health and Safety Risk

Environment, health and safety risks relate primarily to field operations associated with oil and gas assets. To mitigate this risk, a preventative environmental, health and safety program is in place as well as operational loss insurance coverage. Arsenal employees and contractors adhere to the Company's environment, health and safety program, which is routinely reviewed and updated to ensure that the Company operates in a manner consistent with best practices in the industry. The Board of Directors oversees the risk assessment and risk mitigation process.

Regulation, Tax and Royalty Risk

Regulation, tax and royalty risk relates to changing government royalty regulations, income tax laws and incentive programs impacting the Company's financial and operating results. Management, with the assistance of legal and accounting professionals, stay informed of proposed changes in laws and regulations and proactively responds to and plan for the effects of these changes.

Capital Market Risk

The Company's ability to maintain its financial strength and liquidity is dependent upon its ability to access Canadian capital markets. If Canadian debt or equity markets were to become less accessible to the Company, it may affect the ability of Arsenal to continue to replace production.

For a more detailed discussion of the Risk Factors, refer to the Company's Annual Information Form dated March 17, 2010 filed on SEDAR at www.sedar.com.

Critical Accounting Estimates and Policies

The significant accounting estimates and policies used by Arsenal are disclosed in note 1 to the Consolidated Financial Statements for the years ended December 31, 2009 and 2008. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstances may result in actual results or changes to estimate amounts that differ materially from current estimates.

Financial Instruments

Cash and cash equivalents are designated as "held-for-trading" and are measured at carrying value, which approximates fair value due to the short-term nature of these instruments. Accounts receivable are designated as "loans and receivables." Accounts payable and accrued liabilities and revolving demand loan are designated as "other liabilities."

The Company uses financial instruments for non-trading purposes to manage fluctuations in commodity prices. All unrealized derivative financial instruments that either do not qualify as hedges, or are not designated as hedges, are recorded as a derivative asset or a derivative liability on the consolidated balance sheet with any changes in fair value during the period recognized in income.

All financial instruments are required to be measured at fair value on initial recognition of the instrument, except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as "held-for trading," "available-for-sale," "held-to-maturity," "loans and receivables" or "other financial liabilities" as defined by the standard.

Financial assets and financial liabilities classified as "held-for-trading" are measured at fair value, with changes in those fair values recognized in net earnings. Financial assets classified as "available-for-sale" are measured at fair

value, with changes in those fair values recognized in other comprehensive income. Financial assets classified as "held-to-maturity," "loans and receivables" and "other financial liabilities" are measured at amortized cost using the effective interest method of amortization. The methods used by the Company in determining fair value of financial instruments are unchanged as a result of implementing the new standard.

International Financial Reporting Standards ("IFRS")

In February 2008, the CICA Accounting Standards Board ("AcSB") confirmed the changeover to IFRS from Canadian GAAP will be required for publicly accountable enterprises interim and annual financial statements effective for fiscal years beginning on or after January 1, 2011. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by Arsenal for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2011. The eventual changeover to IFRS represents a change due to new accounting standards. Although IFRS is principles-based and uses a conceptual framework similar to Canadian GAAP, there are significant differences and choices in accounting policies, as well as increased disclosure requirements under IFRS. The transition from current Canadian GAAP to IFRS is a significant undertaking that may materially affect the Company's reported financial position and results of operations.

In July 2009, the International Accounting Standards Board ("IASB") has approved amendments and exemptions to IFRS 1 "First-time adoption of IFRS" in order to make it more useful to Canadian entities adopting IFRS for the first time. One such exemption relating to full cost oil and gas accounting reduces the administrative burden in the transition from the current Canadian Accounting Guideline 16 (related to the full cost method of accounting for oil and gas activities) to IFRS. The amendment will permit the Company to apply IFRS prospectively to their full cost pool, rather than the retrospective assessment of capitalized exploration and development expenses, with the provision that an impairment test, under IFRS standards, be conducted at the transition date.

Arsenal is executing its project plan for the transition from current Canadian GAAP to IFRS. Internal staff continues to implement the conversion project and all IFRS requirements will be met with internal employees supplemented with consultants as required. The project team regularly provides updates to senior management and the Audit Committee. We will provide the key elements of our plan and progress on the project as information becomes available during the transition period.

In 2009, our project team completed the scoping and diagnostic phase of our project. This phase involved performing a high level analysis to identify key differences between Canadian GAAP and IFRS. We have started the solution development phase. This phase involves analysis of policy choices allowed under IFRS and their impact on the financial statements. In addition, certain potential differences are being further investigated to assess whether there may be a broader impact to the Company's debt agreement. The conclusion of the solution development phase will require the Audit Committee of the Board of Directors to review and approve all accounting policy choices as proposed by management. Once the solution development phase is complete, the Company will move into the implementation phase which will involve the implementation of all changes approved in the solution development phase and will also include changes to IT systems and accounting processes.

Management has identified the following significant accounting differences between our current accounting policies under Canadian GAAP and expected accounting policies under IFRS include the following:

- Property, Plant and Equipment ("PP&E") - Under Canadian GAAP, the Company applies full cost accounting in which all costs directly associated with the acquisition of, the exploration for, and the development of natural gas and crude oil reserves are capitalized on a country-by-country cost centre basis. Costs accumulated within each country cost centre are depleted using the unit-of production method based on total proved reserves determined using estimated future prices and costs. Upon transition to IFRS, Arsenal will be required to adopt new accounting policies for pre-exploration costs, exploration and evaluation ("E&E") costs and development costs.

Pre-exploration costs are expenditures incurred prior to obtaining the legal right to explore and will be required to be expensed under IFRS. Under Canadian GAAP, Arsenal capitalizes and depletes such costs within the full cost pool.

E&E costs are expenditures incurred at a property where technical feasibility and commercial viability of extracting oil and gas from the property has not been yet determined. Upon transition to IFRS, Arsenal will re-classify all E&E expenditures that are currently included in the PP&E balance on the consolidated balance sheet. E&E assets may not be depleted and must be assessed for impairment when indicators suggest the possibility of impairment.

Development costs are expenditures incurred at a property where technical and commercial feasibility have been determined. Arsenal will continue to capitalize these costs. Under Canadian GAAP, these costs are depleted on a unit-of-production basis at a country cost centre level. Under IFRS development costs will be depleted on a unit-of-production basis over an area level. IFRS provides the option to calculate depletion using a reserve base of total proved reserves or both total proved and total probable reserves, as compared to the Canadian GAAP method of calculating depletion using only proved reserves. Arsenal has chosen to calculate depletion using a reserve base of proved and probable reserves.

Divestitures of an oil and gas property under IFRS will generally result in a gain or loss recognized in earnings. Under Canadian GAAP, proceeds of divestitures are deducted from the full cost pool without recognition of a gain or loss unless the divestiture results in a change to the depletion rate of 20 percent.

- Share-based payments - Under IFRS share based payment are expensed using graded vesting and is based on the estimated number of options expected to vest (forfeitures are estimated). Graded vesting will result in a greater portion of the compensation expense to be recognized sooner.

- Asset Retirement Obligations – Under IFRS any change in the discount rate must be applied to the entire obligation liability and not just the prospective additions to the obligation, which is the current method under Canadian GAAP. IFRS 1 requires that an entity adopting the full cost accounting deemed cost exemption must also measure the decommissioning liability (ARO) associated with PP&E as at the date of transition to IFRS with any impact recorded to retained earnings on adoption.

We are currently in the process of evaluating the impact of the above noted accounting policy choices as well as potential IFRS 1 exemptions and the effect they will have on our financial statements. We will disclose additional information on the impact of the changes throughout 2010. Any amendments to existing IFRS standards or implementation of new IFRS standards could lead to additional changes.

In addition to accounting changes, the transition to IFRS will impact internal controls over financial reporting (“ICFR”), the disclosure controls and procedures and other areas of Arsenal’s business. This will involve disclosure and explanations in investor presentations and in shareholder publications explaining the differences between the current GAAP and the IFRS statements. As the evaluation process proceeds, Arsenal will assess the changes required for ICFR and to stakeholder’s requirements as a result of the accounting policies and requirements under IFRS. In addition, Arsenal has had discussions with its counterparties, particularly its bankers to ensure there are no unforeseen agreement issues as a result of conversion to IFRS.

Disclosure Controls and Procedures

The Company has established disclosure controls and procedures for the timely and accurate preparation of financial and other reports. Disclosure controls and procedures are designed to provide reasonable assurance that material information required to be disclosed is recorded, processed, summarized and reported within the periods specified by applicable securities regulations and that information required to be disclosed is accumulated and communicated to the appropriate members of management and properly reflected in the Company’s filings. Consistent with the concept of reasonable assurance, the Company recognizes that the relative cost of maintaining

these disclosure controls and procedures should not exceed their expected benefits. As such, the Company's disclosure controls and procedures can only provide reasonable assurance, and not absolute assurance, that the objectives of such controls and procedures are met. The Chief Executive Officer and the Chief Financial Officer oversee this evaluation process and have concluded that the design and operation of these disclosure controls and procedures are not effective in providing reasonable assurance that material information required to be disclosed by the Company in reports filed with Canadian securities regulators is accurate and complete and filed within the periods required due to the material weaknesses identified in internal controls over financial reporting as noted below. The Chief Executive Officer and the Chief Financial Officer have individually signed certifications to this effect. There were no changes during the six month ended June 30, 2010 in disclosure controls and procedures.

Internal Controls over Financial Reporting

The Chief Executive Officer and Chief Financial Officer of Arsenal are responsible for designing internal controls over financial reporting or causing them to be designed and their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. Arsenal's management has assessed the design of internal controls over financial reporting.

While Arsenal's Chief Executive Officer and Chief Financial Officer believe the Company's internal controls and procedures provide a reasonable level of assurance that they are reliable, an internal control system cannot prevent all errors and fraud. It is management's belief that any control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

During the design assessment certain material weaknesses in internal controls over financial reporting were identified, as follows:

- Management is aware that there is a lack of segregation of duties due to the small number of employees dealing with general administrative and financial matters. However, management believes that at this time the potential benefits of adding employees to clearly segregate duties do not justify the costs associated with such increase;
- Many of Arsenal's information systems are subject to general control deficiencies including a lack of effective controls over spreadsheets, access and documentation. The Company expects that these deficiencies will continue into the future; and
- Arsenal does not have full-time in-house personnel to address all complex and non-routine financial and tax issues that may arise. It is not deemed as economically feasible at this time to have such personnel. Arsenal relies on external experts for review and advice on complicated financial and tax issues and for tax planning, tax provision and compilation of corporate tax returns.

These weaknesses in internal controls over financial reporting result in a more than remote likelihood that a material misstatement would not be prevented or detected. Management and the Board of Directors work to mitigate the risk of material misstatement; however, management and the Board do not have reasonable assurance that this risk can be reduced to a remote likelihood of a material misstatement. There were no changes during the six months ended June 30, 2010 to material weaknesses in internal controls over financial reporting.