MANAGEMENT DISCUSSION AND ANALYSIS

2011 Financial and Operational Highlights

SUMMARY OF FINANCIAL AND OPERATIONAL RESULTS						
	Three Months Ended June 30			Six Months Ended June 30		
	2011	2010	% Change	**2011**	2010	% Change
FINANCIAL						
Oil and gas revenue	**12,729,872**	11,128,046	**14**	**24,349,016**	22,714,559	**7**
Cash provided by operation activities	**4,096,938**	3,581,654	**14**	**8,364,894**	7,080,205	**18**
Funds from operations	**4,301,767**	4,007,438	**7**	**9,407,402**	9,196,842	**2**
Per share - basic	**0.03**	0.03	**(10)**	**0.06**	0.07	**(15)**
-diluted	**0.03**	0.03	**(9)**	**0.06**	0.07	**(15)**
Net income (loss)	**3,011,927**	574,690	**424**	**(4,927,929)**	505,623	**(1,075)**
Per share - basic	**0.02**	nil	**-**	**(0.03)**	nil	**-**
-diluted	**0.02**	nil	**-**	**(0.03)**	nil	**-**
Total debt	**9,931,680**	19,886,286	**(50)**	**9,931,680**	19,886,286	**(50)**
Capital expenditures	**6,104,750**	2,260,705	**170**	**18,255,491**	9,348,061	**95**
Property dispositions	**-**	-	**-**	**598,509**	(214,831)	**(379)**
Wells drilled (net)						
Oil	**-**	-	**-**	**1.03**	2.15	**(52)**
Gas	**-**	-	**-**	**-**	-	**-**
Dry	**-**	-	**-**	**2.00**	-	**-**
Total net wells drilled	**-**	-	**-**	**3.03**	2.15	**41**
Shares outstanding - end of period	**161,761,062**	134,195,472	**21**	**161,761,062**	134,195,472	**21**
OPERATIONAL						
Daily production						
Heavy oil (bbl/d)	**504**	644	**(22)**	**526**	643	**(18)**
Light oil and NGLs (bbl/d)	**1,004**	1,051	**(5)**	**1,051**	989	**6**
Natural gas (mcf/d)	**1,908**	2,189	**(13)**	**2,017**	2,849	**(29)**
Oil equivalent (boe @ 6:1)	**1,826**	2,060	**(11)**	**1,913**	2,107	**(9)**
Realized commodity prices ($Cdn.)						
Heavy oil (bbl)	**79.08**	**60.51**	**31**	**73.15**	64.96	**13**
Light oil and NGLs (bbl)	**92.27**	**70.44**	**31**	**84.18**	71.23	**18**
Natural gas (mcf)	**3.88**	**4.24**	**(8)**	**3.75**	4.65	**(19)**
Oil equivalent (boe @ 6:1)	**76.62**	**59.37**	**29**	**70.31**	59.55	**18**
Operating netback ($ per boe)						
Revenue	**76.62**	**59.37**	**29**	**70.31**	59.55	**18**
Royalty	**(15.42)**	**(11.32)**	**36**	**(13.22)**	(10.03)	**32**
Operating cost	**(20.34)**	**(21.48)**	**(5)**	**(17.99)**	(20.46)	**(12)**
Transportation cost	**(2.42)**	**(0.87)**	**178**	**(1.82)**	(1.05)	**73**
Operating netback per boe	**38.45**	**25.70**	**50**	**37.28**	28.01	**33**
General and administrative	**(7.54)**	**(5.53)**	**36**	**(6.68)**	(4.82)	**38**
Finance expenses	**(1.95)**	**(1.90)**	**2**	**(1.30)**	(1.61)	**(19)**
Other	**(0.06)**	**0.13**	**(144)**	**0.09**	0.24	**(61)**
Realized hedging gains (losses)	**(3.01)**	**2.97**	**(201)**	**(2.23)**	2.29	**-**
Funds flow per Boe	**25.89**	**21.38**	**21**	**27.16**	**24.11**	**13**

In Q2 2011, the Company set a new quarterly high for revenue of $12.7 million, a 9% increase over Q1 record revenue of $11.6 million. Funds flow before the effect of commodity contracts totaled $4.8 million, down from $5.4 million in Q1 2011 due to lower production resulting from of wet field conditions and road closures. The Company continues to increase its operating netback, realizing an operating netback of $38.45 per Boe for the quarter.

Funds from operations (after realized losses on commodity contracts) for Q2 2011 totaled $4.3 million or $0.03 per share basic and diluted compared to $5.1 million or $0.03 per share basic and diluted in Q1 2011 and $4.0 million or $0.03 per share basic and diluted in Q2 2010. For the six month period ended June 30, 2011, funds from operations totaled $9.4 million or $0.06 per share basic and diluted compared to $9.2 million or $0.07 per share basic and diluted in the comparative 2010 six month period. Funds from operations for 2011 were reduced by lower production due to severe weather and lease flooding and realized losses on commodity contracts.

For Q2 2011, the Company's operating netback per Boe (revenues less royalties, operating and transportation expenses) increased 6% to $38.45 per Boe from $36.20 in Q1 2011 and by 50% from $25.70 in Q1 2010. Cash netback per Boe (funds from operations per Boe) decreased 9% to $25.89 per Boe from $28.34 in Q1 2011 and increased by 21% from $21.38 in Q2 2010. The decrease in Q2 2011 from Q1 2011 is due to lower production and higher transportation and general and administrative expenses. The increase in Q2 2011 from Q2 2010 was due to increased crude prices, improved operating initiatives, the sale of high cost operating properties and a higher proportion of low cost production from the US.

In June 2011, the Company's approved credit facility was increased 50% from $40.0 million to $60.0 million. The Company's total debt (see Credit Facility) was $9.9 million at June 30, 2011 down from $18.8 million at December 31, 2010. The Company's debt decreased in 2011 primarily due to an equity financing in February 2011 that generated gross proceeds of $21.1 million.

During Q2 2011, the Company initiated completion operations on two high interest operated Bakken wells in North Dakota. These wells (1.4 net) should add significantly to US and corporate production revenue and cash flow in Q3 2011 and onward.

Arsenal's production for Q2 2011 averaged 1,826 Boe per day (83% crude oil and NGL's and 17% natural gas) versus a Q1 2011 average of 2,002 Boe per day (82% crude oil and NGL's and 18% natural gas) and a Q2 2010 average of 2,060 Boe per day (82% crude oil and NGL's and 18% natural gas). One North Dakota Bakken well was shut in for the quarter due to access difficulties and waiting on equipment for remedial work. The percentage of crude oil production should increase due to added production from the two Bakken North Dakota wells and the shut in well now being back on production.

Capital expended to June 30, 2011 totaled $18.3 million versus $9.3 million for the six month 2010 period. Capital expenditures in Canada were to drill at Evi, to purchase land and construct facilities at Princess and to shoot seismic at Edgerton. In the US, capital was expended drilling two Bakken wells. In 2011, the Company disposed of three non-core property for proceeds of $598,509.

On June 16, 2011, the Company announced its intention to make a normal course issuer bid ("NCIB") that commenced June 20, 2011 and ends June 19, 2012. A total of 8,128,724 common shares may be acquired under the bid representing 5% of the common shares outstanding as of June 14, 2011. To date, the Company has purchased 831,743 common shares at an average cost of $0.65 per share plus expenses.

Arsenal has 161,761,062 common shares and 14,543,670 stock options outstanding as of August 9, 2011. The Company's shares are listed and posted for trading on the Toronto Stock Exchange under the symbol "AEI".

In Canada, the Company operates under Arsenal Energy Inc. Production in Canada averaged 1,245 Boe per day for the current quarter. In the US, the Company operates under its 100% owned subsidiary Arsenal Energy USA Inc. Production from the US averaged 581 Boe per day for the current quarter.

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 months ended March 31, 2011. 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, 2011 and the audited consolidated financial statements and related notes and MD&A for the year ended December 31, 2010. This MD&A is dated August 9, 2011.

The condensed interim consolidated financial statements and comparative information has been prepared in accordance with International Financial Reporting Standards ("IFRS") and International Accounting Standard 34 "Interim Financial Reporting". Previously the Company prepared its interim and annual consolidated financial statements in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). These previously reported consolidated financial statements were adjusted to be in compliance with IFRS on January 1, 2010, the "date of adoption". Previously reported results and balances subsequent to the date of adoption have been restated to IFRS. The adoption of IFRS has not had a material impact on the Company's operations, strategic decisions or cash flow from operations before changes in non-cash working capital.

Unless otherwise specified, all dollar amounts are stated in Canadian dollars, and all references to "dollars" or "$" are to Canadian dollars.

Tables may not add due to rounding.

Certain prior period amounts have been reclassified to conform to the current period's presentation.

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, constitute forward looking statements. These statements relate to future events or 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', 'propose', 'project', 'predict', 'potential', 'targeting', 'intend', 'could', 'might', 'should', 'believe' and similar expressions or the negative of these terms or other comparable terminology and are generally intended to identify forward looking statements. 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 this MD&A should not be unduly relied upon. These statements speak only as of the date of this MD&A. 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 MD&A: 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 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 equivalent unless otherwise stated. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of six Mcf to one barrel of oil equivalent 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.

“Funds from operations”, “Funds from operations per share”, “Operating Netbacks per unit or per Boe”, “Netbacks per unit or per Boe”, “Net Debt”, “Total Debt” or “Bank Debt” are not defined by IFRS in Canada and are regarded as non-IFRS measures.

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 year or quarter 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 realized gains or losses on commodity contracts less cash expenses for general and administrative, financing charges and other fees and other expenses calculated on a Boe basis.

Total debt is defined as bank borrowings plus working capital (excess or deficiency) and excludes decommissioning obligations and the value of risk management contracts (whether an asset or an obligation).

Funds from Operations

Funds from operations are not recognized by IFRS in Canada but it is used by the Company, investors, analysts, bankers and others to evaluate and compare oil and gas exploration and producing entities.

Funds from operations are determined by cash flow from operations before the change in non-cash operating working capital, seismic expenses and decommissioning obligations settled. The Company's banker uses funds from operations to measure debt to funds flow ratios that determine interest costs to the Company under its credit facility. Funds from operations are used to analyze the Company's performance, the ability of the business to generate the cash flow necessary to fund growth through capital investment and to repay bank debt. Funds from operations should not be considered as an alternative to, or more meaningful than cash provided from operating activities as determined in accordance with IFRS 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 basic is calculated based on the weighted average number of common shares outstanding consistent with the calculation of earnings per share. Funds from operations per diluted share are calculated based on the weighted average number of common shares outstanding adjusted for dilutive instruments which in Arsenal's case are only stock options.

The following tables compare cash provided by operating activities to funds from operations, funds from operations by country and funds from operations netback per Boe for Q2 2011 to Q2 2010 and for the six month period ended June 30, 2011 and June 30, 2010. These numbers are referred to in this MD&A:

Funds from Operations	**Three Months Ended June 30**			**Six Months Ended June 30**		
($Cdn.)	**2011**	2010	% Change	**2011**	2010	% Change
Cash provided by operations	**4,096,938**	3,581,654	14	**8,364,894**	7,080,205	18
Seismic expenses	**3,793**	30,844		**735,841**	1,488,085	
Decommissioning obligations settled	**201,036**	394,940	(49)	**306,667**	628,552	(51)
Funds from operations	**4,301,767**	4,007,438	7	**9,407,402**	9,196,842	2

Funds From Operations By Country	**Three Months Ended June 30**			**Six Months Ended June 30**		
($Cdn.)	**2011**	2010		**2011**	2010	
Canada	**2,684,082**	2,152,748	25	**6,011,413**	6,219,084	(3)
US	**1,617,685**	1,854,690	(13)	**3,395,989**	2,977,758	14
Funds from operations	**4,301,767**	**4,007,438**	7	**9,407,402**	**9,196,842**	2

Funds From Operations Netback per Boe	**Three Months Ended June 30**			**Six Months Ended June 30**		
($Cdn.)	**2011**	2010	% Change	**2011**	2010	% Change
Canada	**23.70**	17.16	38	**25.80**	22.52	15
US	**30.59**	29.94	2	**29.97**	28.30	6
Total	**25.89**	21.38	21	27.16	24.11	13

The following table compares the quarterly 2011 to date and 2010 funds from operations and the funds from operations per boe both before and after the effect of commodity contracts.

Funds From Operations	**2011**		2010				**2009**
($Cdn.)	**Q2**	**Q1**	Q4	Q3	Q2	Q1	Q4
Before commodity contracts	**4,802,027**	**5,376,546**	**4,774,831**	**2,987,571**	**3,450,436**	**4,871,046**	**3,447,852**
Effect of realized comodity contracts	**(500,260)**	**(271,011)**	**267,123**	**646,141**	**557,002**	**318,358**	**24,058**
After commodity contracts	**4,301,767**	**5,105,535**	**5,041,954**	**3,633,712**	**4,007,438**	**5,189,404**	**3,471,910**
Per Boe							
Before commodity contracts	**28.90**	**29.84**	**24.34**	**16.03**	**18.41**	**25.13**	**20.02**
After commodity contracts	**25.89**	**28.34**	**25.70**	**19.50**	**21.38**	**26.77**	**20.16**

The increase over the above periods relate to increasing crude prices, higher operating netbacks as a result of operating cost efficiencies, the disposition of high operating cost properties and lower finance expenses.

OUTLOOK AND 2011 GUIDANCE

Despite reduced production due to inclement weather, flooding and road closures in western Canada and North Dakota and a pipeline break somewhat curtailing production in Alberta, the Company generated revenues from oil and gas production of $12.7 million. The Company increased its operating netback during Q2 2011, despite higher operating and trucking costs, to $38.45 per Boe. With a favourable pricing regime, increased production from recent completions and upcoming drilling and normal weather and ground conditions, the Company should realize further increases in its revenues and netbacks during the remainder of 2011 and during 2012.

The Company’s current debt position combined with the Company’s expected funds flow for 2011 and increased credit facility provides the Company with a strong balance sheet and financial strength and flexibility. This financial strength has given the Company the flexibility to plan an aggressive capital program in 2011.

The Company will now focus on core properties in Canada and the US with a longer reserve life. Over the past two years, the Company has dedicated a large portion of its capital budget to development of its Stanley and Lindahl properties in North Dakota. The Company has a working interest in a number of high working interest operated wells in Stanley, North Dakota, two of which have been recently completed and a number more scheduled to be drilled later in 2011. As well, the Company is expecting to participate in a number of non-operated lower working interest wells in early 2012. At Lindahl, the Company expects the operator in the area (Continental) to drill on our lands from a common drilling pad. The Company is expecting to participate at an approximate 6% - 8% working interest in these 4 gross non operated wells in 2012.

New prospects to be drilled this summer at Chauvin, Princess and Edgerton, should provide the Company with a more balanced, capital expenditure program. Arsenal has three play concepts that will be tested in the latter part of 2011. At Edgerton, Alberta, Arsenal, in Q1 2011, shot and interpreted a 3D seismic program and identified a large Leduc subcrop structure. A horizontal well is scheduled to be drilled in late Q3 2011. At Princess, Alberta, Arsenal is installing high volume lift and upgrading facilities to test the productive capability of its 5 Detrital formation wells. Also at Princess, Arsenal plans to drill horizontal wells in Q3 2011 into the Glauconitic formation to test multi fracturing technology to increase production. Each of these has the potential to prove up material oil development opportunities for Arsenal going forward. At Chauvin, the Company has developed both a Leduc reef prospect and a Rex channel project scheduled for testing (by drilling) later this year.

Volumes in the second quarter were negatively impacted by weather conditions in Alberta and North Dakota where localized flooding, power outages and road closures resulted in significant production downtime for all operators in Alberta and North Dakota, including Arsenal. Volumes are now near full capacity and in should fact increase in Q3 due to recent well completions in North Dakota.

In North Dakota, smaller operators like Arsenal generally rely on windows to execute operations. The tight equipment environment in North Dakota has been exacerbated by bad weather. Fracs on Arsenal’s two wells are now complete. One well is now on production while the other requires some clean up prior to being turned over to production.

The Company’s capital expenditure program for 2011 is planned to total from between $45.0 and $50.0 million. Total expenditures will depend on the timing of the fracs in North Dakota and on the number of Bakken and Three Forks wells drilled in North Dakota by Arsenal.

Based on current strip prices and current plans, including the magnitude of capital expenditures, the expected timing of completion services, the on-stream dates and rates of new production and spud dates for new wells the Company is expected to average from between 2,100 and 2,200 Boe per day for 2011. The exit rate for 2011 is estimated at approximately 2,500 Boe per day. Funds from operations for 2011 are estimated to be approximately $25.0 million and total debt at year end 2011 is estimated to be approximately $25.0 million.

PRODUCTION AND REVENUE

Average Daily Production

Production for Q2 2011 averaged 1,826 Boe per day versus 2,002 Boe per day in Q1 2011 and 2,060 Boe per day in Q2 2010. For the six month period ended June 30, 2011, production averaged 1,913 Boe per day versus 2,107 Boe per day in the comparative six month 2010 period. Production for Q1 and Q2 2011 was reduced due to the extremely wet conditions in Western Canada and in North Dakota that limited the ability of the Company to access leases to empty tanks and to service wells and due to a pipeline break in Alberta. These extremely wet conditions have improved but production in some areas is just being restored with a minor amount still offline. Current production, including the Company's share of the recently completed Brenlee well in North Dakota, is estimated at approximately 2,400 Boe per day. Production should increase once the second North Dakota well is on production.

The Company produces in the provinces of Alberta and Saskatchewan in Canada (68% of total Q2 2011 production) and in the state of North Dakota in the US (32% of total Q2 2011 production). The percentage of production from the US dropped slightly in Q2 2011 from Q1 2011 (34%) due to extremely wet ground conditions that hampered the Company's ability to haul crude off leases and to service wells. US production is expected to increase over time as a percentage of total production as the Company commences production from its high rate, high working interest Bakken wells in North Dakota.

Production from the Bakken formation is characterized by high initial production followed by production declines within a few months, after which, production declines and tends to level out. In addition, the production is characterized by low operating costs.

Production Profile

Average Daily Production	Three Months Ended June 30			Six Months Ended June 30		
	2011	2010	% Change	**2011**	2010	% Change
Canada						
Heavy oil	504	644	(22)	526	643	(18)
Light oil and NGL's	481	428	12	500	453	10
Natural gas	1,557	1,842	(15)	1,567	2,582	(39)
Total Boe	1,245	1,379	(10)	1,287	1,526	(16)
US						
Heavy oil	-	-	-	-	-	-
Light oil and NGL's	523	623	(16)	551	537	3
Natural gas	351	347	1	450	267	68
Total Boe	581	681	(15)	626	581	8
Corporate						
Heavy oil	504	644	(22)	526	643	(18)
Light oil and NGL's	1,004	1,051	(5)	1,051	989	6
Natural gas	1,908	2,189	(13)	2,017	2,849	(29)
Total Boe	1,826	2,060	(11)	1,913	2,107	(9)

Percentage Split - By Commodity	**Three Months Ended June 30**			**Six Months Ended June 30**		
Heavy oil	**28%**	31%	(12)	**27%**	30%	(10)
Light oil and NGLs	**55%**	51%	8	**55%**	47%	17
Natural gas	**17%**	18%	(2)	**18%**	23%	(22)

Production Split - By Country	Three Months Ended June 30			Six Months Ended June 30		
Canada	**68%**	**67%**	2	**67%**	72%	(7)
US	**32%**	**33%**	(4)	**33%**	28%	19

Production by Area

	Three Months Ended June 30				**Six Months Ended June 30**			
	2011		2010		**2011**		2010	
AREA	**Boe/d**	**% of Total**	Boe/d	% of Total	**Boe/d**	**% of Total**	Boe/d	% of Total
Canada								
Galahad (light oil and solution gas)	245	13	118	6	269	14	193	9
Wildmere (heavy oil)	-	-	71	3	-	4	80	4
Chauvin/Ribstone (medium oil and gas	314	17	337	16	316	16	346	16
West Current (BC gas)	-	-	62	3	-	4	67	3
Evi (light oil)	253	14	261	11	248	13	242	11
Others	433	24	530	26	454	24	598	28
Total Canada	**1,245**	68	1,379	67	**1,287**	67	1,526	72
US								
Stanley (light oil)	287	16	397	19	314	16	332	16
Lindahl (light oil)	182	10	187	9	210	11	164	8
Rennie Lake (light oil)	44	2	29	2	51	3	35	2
Others	68	4	68	3	51	3	50	2
Total US	**581**	32	681	33	**626**	33	581	28
Total	**1,826**	100	2,060	100	**1,913**	100	2,107	100

In Q3 2010, the Company sold its interests at Wildmere and West Current. The increase in the Galahad production results from production of a solution gas cap that started in Q3 2010 and that has subsided over the past few quarters and been replaced by higher crude production from the wells. New Evi production has not offset declines over the quarters. The Company typically drills at Evi in Q1 and Q4 adding high initial rate production. Evi wells typically decline substantially during their first few months of production. Production was added from drilling at Stanley and Lindahl where high initial rate production declines quickly and stabilizes in 6 – 9 months. The current production rates at Stanley and Lindahl have a lower decline rate than when new wells are first put on production. Production at Stanley will increase substantially with the two newly completed wells at Stanley. Arsenal's other properties experienced normal production declines.

Revenue

Prices

Prices - Before Commodity Contracts	Three Months Ended June 30			Six Months Ended June 30		
($Cdn.)	**2011**	2010	% Change	**2011**	2010	% Change
Canada						
Heavy oil per barrel	79.08	60.51	31	73.15	64.96	13
Light oil and NGL's per barrel	94.86	70.93	34	86.02	69.77	23
Natural gas per mcf	3.72	4.27	(13)	3.62	4.64	(22)
Total per Boe	73.35	55.98	31	67.72	55.93	21
US						
Heavy oil per barrel	-	-	-	-	-	-
Light oil and NGL's per barrel	89.88	70.11	28	82.50	72.45	14
Natural gas per mcf	4.61	4.09	13	4.20	4.69	(10)
Total per Boe	83.62	66.24	26	75.64	69.06	10
Total						
Heavy oil per barrel	79.08	60.51	31	73.15	64.96	13
Light oil and NGL's per barrel	92.27	70.44	31	84.18	71.22	18
Natural gas per mcf	3.88	4.24	(8)	3.75	4.65	(19)
Total per Boe	76.62	59.37	29	70.31	59.55	18

Reference Prices	Three Months Ended June 30			Six Months Ended June 30		
	2011	2010	% Change	**2011**	2010	% Change
WTI Cushing, Oklahoma ($U.S./bbl)	**102.55**	77.89	32	**98.08**	78.28	25
Light Oil Edmonton Par 40 API ($Cdn./bl	**103.59**	75.44	37	**96.05**	77.87	23
Hardisty Bow River 24.9 API ($Cdn./bbl	**83.29**	66.40	25	**86.93**	74.39	17
AECO (daily spot) ($Cdn./MMBtu)	**3.97**	3.90	2	**3.84**	4.43	(13)
Henry Hub NYMEX Close ($U.S./MMBu)	**4.32**	4.09	6	**4.21**	4.70	(10)
Foreign exchange ($Cdn./$U.S.)	**1.03**	0.97	6	**1.02**	0.97	5

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 price of heavy oil and light oil and NGL's increased 31% and 34% respectively in Canada in the current quarter and 13% and 23% for the current six month period. The current quarter increase in the price of light oil over the previous quarter was 37% and the current period to date increased 23% over the 2010 six month period. The increase in the Hardisty Bow River stream, that represents a reference price of the average price the Company receives for its heavy oil, increased 25% in the current quarter over Q2 2010 and 17% in the current six month period over the 2010 comparative period.

In the US, the increase in WTI (25% over the previous quarter and 25% over the previous six month period) was somewhat negated by the strengthening of the Canadian dollar (up 6% over prior comparative quarter and 5% over prior six month period) and the higher North Dakota differentials. Light oil price received was 28% higher in the 2011 current quarter than in Q2 2010 and 14% higher than the prior six month comparative period. The price received for natural gas during the current quarter was up 13% from the prior year comparable quarter in line with the 6% increase at Henry Hub while the current year six month price declined 10% in the US consistent with a decline in natural gas prices in North America over this period.

The Company received an average price per Boe during Q2 2011 of $76.62 per Boe an increase of 29% from $59.37 per Boe received in Q2 2010. For the six month 2011 period, the average price received was $70.31 per Boe up 18% from the six month period ended June 30, 2010. This increase is primarily attributed to a higher price for light oil and NGL's and is consistent with the upward movement in crude prices over these periods.

Oil and Natural Gas Revenue

	Three Months Ended June 30			Six Months Ended June 30		
($Cdn.)	**2011**	2010	% Change	**2011**	2010	% Change
Canada						
Heavy oil	3,627,205	3,544,020	2	6,968,246	7,563,149	(8)
Light oil and NGL's	4,153,046	2,765,468	50	7,784,507	5,714,645	36
Natural gas	527,014	714,928	(26)	1,026,760	2,170,308	(53)
Total	8,307,265	7,024,416	18	15,779,513	15,448,102	2
US						
Heavy oil	-	-	-	-	-	-
Light oil and NGL's	4,275,412	3,974,275	8	8,227,594	7,039,517	17
Natural gas	147,195	129,355	14	341,909	226,940	51
Total	4,422,607	4,103,630	8	8,569,503	7,266,457	18
Total						
Heavy oil	3,627,205	3,544,020	2	6,968,246	7,563,149	(8)
Light oil and NGL's	8,428,458	6,739,743	25	16,012,101	12,754,162	26
Natural gas	674,209	844,283	(20)	1,368,669	2,397,248	(43)
Oil and natural gas revenues	**12,729,872**	11,128,046	14	**24,349,016**	22,714,559	7
Gain (loss) on realized commodity contracts	**(500,260)**	557,002	(190)	**(771,271)**	875,360	(188)
Oil and gas revenue after commodity contracts	**12,229,612**	11,685,048	5	**23,577,745**	23,589,919	(0)
Per boe before commodity contracts	**76.62**	59.37	29	**70.31**	59.55	18
Per boe after commodity contracts	**73.61**	62.34	18	**68.08**	61.84	10

Total oil and natural gas revenues for Q2 2011 increased 14% when compared to Q2 2010 due to an increase in the average price per Boe of 29%. Increased prices offset a production decreased of 11% and an increase in the Canadian dollar of 6% (thereby reducing US revenues in Canadian dollars).

For the 2011 six month period, total oil and gas revenues increased 7%. An 18% increase in the average price received to $70.31 per Boe was offset by a production decrease over the comparable period of 9% and a 5% increase in the Canadian dollar.

Commodity Price Risk Management

Financial instrument contracts are recorded in the consolidated financial statements at fair value at each reporting period with the change in fair value being recognized as an unrealized gain or loss in the consolidated statements of income (loss) and comprehensive income (loss). In Q1 2011, the Company recorded a loss of $3.2 million on its commodity contracts. In Q2 2011, because of a drop in future commodity prices from March 31, 2011, the Company recorded a gain of $2.3 million resulting in a 2011 six month loss of $878,735. The six month loss is a combination of a realized loss of $771,271 ($2.23 per Boe) and an unrealized loss of $107,464 ($0.31 per Boe). The unrealized loss of $107,464 relates to contracts whose settlement dates are in the future and is based on a June 30, 2011 WTI forward strip price in Canadian dollars (based on the settlement dates of the Company's contracts) of approximately $95.25. The prices can and do change with changes to the WTI forward strip prices and to the Canadian/US exchange rate as demonstrated by the change from March 31, 2011 to June 30, 2011. As some of the

Company's commodity contracts were put in place in early and mid 2010 when the forward strip price of WTI in Canadian dollars was not as high as it is currently, it is expected that, based on current prices, the Company's gain or losses on these contracts will be affected by market volatility and continue to fluctuate.

The price the Company ultimately realizes on its commodity contracts fluctuates monthly with the movement in the price of WTI in Canadian dollars.

The Company has a policy of entering into commodity contracts to stabilize funds from operations against volatile commodity prices in order to ensure a certain level of capital reinvestment and to protect the metrics of significant acquisitions.

The following table details the financial commodity contracts the Company has in place as at June 30, 2011 and the fair value of those contracts recorded in the financial statements as at June 30, 2011.

($Cdn.)

Commodity Sold	Volume Sold	Remaining Term	Price	Fair Value
Oil	100 bbl per day	July 1, 2011 - Dec 31, 2011	85.50 per bbl	(150,502)
Oil	100 bbl per day	July 1, 2011 - Dec 31, 2012	89.50 per bbl	(77,234)
Oil	100 bbl per day	July 1, 2011 - Dec 31, 2012	87.05 per bbl	(497,593)
Oil	100 bbl per day	July 1, 2011 - Dec 31, 2011	88.00 per bbl	(104,710)
Oil	100 bbl per day	Jan 1, 2012 - Dec 31, 2012	90.65 per bbl	(245,896)
Oil	100 bbl per day	July 1, 2011 - Dec 31, 2011	93.30 per bbl	(7,629)
Oil	300 bbl per day	Jan 1, 2012 - Dec 31, 2012	95.15 per bbl	(251,747)
Oil	200 bbl per day	July 1, 2011 - Dec 31, 2013	96.33 per bbl	(192,666)
				(1,527,977)

In August 2011, the Company entered into an additional crude oil commodity price contract as follows:

($Cdn.)

Commodity Sold	Volume Sold	Term	Pricing
Oil	300 bbl per day	January 1, 2013 - Dec 31, 2013	95.10 per bbl

In August 2011, the Company monetized all of the above commodity contracts for proceeds of $4.5 million.

Royalties

	Three Months Ended June 30			Six Months Ended June 30		
($Cdn.)	**2011**	2010	% Change	**2011**	2010	% Change
Canada						
Heavy oil	621,434	450,228	38	1,154,547	996,075	16
Light oil and NGL's	681,249	602,305	13	1,145,171	998,642	15
Natural gas	34,790	44,558	(22)	18,504	36,561	(49)
Total	1,337,473	1,097,091	22	2,318,222	2,031,278	14
US						
Heavy oil	-	-	-	-	-	-
Light oil and NGL's	1,193,260	1,000,713	19	2,191,069	1,767,889	24
Natural gas	31,186	24,106	29	69,565	25,953	168
Total	1,224,446	1,024,819	19	2,260,634	1,793,842	26
Total						
Heavy oil	621,434	450,228	38	1,154,547	996,075	16
Light oil and NGL's	1,874,509	1,603,018	17	3,336,240	2,766,531	21
Natural gas	65,976	68,664	(4)	88,069	62,514	41
Royalties	**2,561,919**	2,121,910	21	**4,578,856**	3,825,120	20

Percentage By Product	Three Months Ended June 30			Six Months Ended June 30		
	2011	2010	% Change	**2011**	2010	% Change
Heavy oil	17	13	34	17	13	26
Light oil and NGL's	22	24	(6)	21	22	(4)
Natural gas	10	-	-	6	-	-
Total	20	19	6	19	17	12

Percentage By Country	Three Months Ended June 30			Six Months Ended June 30		
	2011	2010	% Change	**2011**	2010	% Change
Canada	16	15	4	15	13	12
US	28	25	11	26	25	7
Total	20	19	6	19	17	12

The Company's royalty rate for Q2 2011 averaged 20% versus a rate of 17% in Q1 2011 and 19% in Q2 2010. For the 2011 six month period, the royalty rate averaged 19% versus 17% in the prior six month period in 2010. The higher Q2 2011 rate when compared to the Q1 2011, the Q2 2010 and the higher current six month period rate relate to higher royalties on new US production (US royalty rates increased 11% in current quarter and 7% in current six month period) slightly higher royalties on Alberta production as low royalty rate production at Evi declines and the low royalty period expires.

Royalty rates going forward are expected to average in the 20% - 22% range. The rate fluctuates due to adjustments to the Company's gas cost allowance and to some degree commodity prices, the start and expiry of low royalty rate periods and production rates. Increases or decreases in the dollar value of royalties are production and commodity price related. Continued added production from the US will increase the corporate average royalty rate as US royalty rates paid by the Company are higher than those in Canada.

Per Boe	**Three Months Ended June 30**			**Six Months Ended June 30**		
($Cdn.)	**2011**	2010	% Change	**2011**	2010	% Change
Canada						
Heavy oil per barrel	13.55	7.69	76	12.12	8.56	42
Light oil and NGL's per barrel	15.56	15.45	1	12.65	12.19	4
Natural gas per mcf	0.25	0.27	8	0.07	0.08	17
Total per Boe	11.81	8.74	35	9.95	7.35	35
US						
Heavy oil per barrel	-	-	-	-	-	-
Light oil and NGL's per barrel	25.09	17.65	42	21.97	18.20	21
Natural gas per mcf	0.98	0.76	28	0.85	0.54	59
Total per Boe	23.15	16.54	40	19.95	17.05	17
Total						
Heavy oil per barrel	13.55	7.69	76	12.12	8.56	42
Light oil and NGL's per barrel	20.52	16.75	22	17.54	15.45	14
Natural gas per mcf	0.38	0.34	-	0.24	0.12	99
Royalties per Boe	15.42	11.32	36	13.22	10.03	32

On a Boe basis, the Q2 2011 royalty was $ 15.42 per Boe versus $11.19 per Boe for Q1 2011 and $11.32 per Boe for Q2 2010. For the 2011 six month period, the Company paid $13.22 per Boe in royalties versus $10.03 per Boe in the 2010 six month period. These rates are in line with the changes to commodity prices over the respective periods and the royalty rates on new production from drilling. An increase in the per Boe rate is expected as a result of the higher percentage of revenue from the US that generally has higher royalty rates than in Canada. As royalty holiday periods expire and as higher US royalty production is brought on-stream, the rate per Boe is expected to increase and rates are expected to average the higher side of the expected range.

Operating Expenses

($Cdn.)	Three Months Ended June 30			Six Months Ended June 30		
	2011	2010	% Change	**2011**	2010	% Change
Canada						
Heavy oil	1,096,778	1,544,218	(29)	2,143,343	3,178,622	(33)
Light oil and NGL's	923,973	1,085,588	(15)	1,611,584	2,150,377	(25)
Natural gas	566,630	515,145	10	1,069,578	797,925	34
Total	2,587,381	3,144,951	(18)	4,824,505	6,126,924	(21)
US						
Heavy oil	-	-	-	-	-	-
Light oil and NGL's	791,256	881,748	(10)	1,406,833	1,677,524	(16)
Natural gas	-	-	-	-	-	-
Total	791,256	881,748	(10)	1,406,833	1,677,524	(16)
Total						
Heavy oil	1,096,778	1,544,218	(29)	2,143,343	3,178,622	(33)
Light oil and NGL's	1,715,229	1,967,336	(13)	3,018,417	3,827,901	(21)
Natural gas	566,630	515,145	10	1,069,578	797,925	34
Operating expenses	**3,378,637**	4,026,699	(16)	**6,231,338**	7,804,448	(20)

Per Boe	Three Months Ended June 30			Six Months Ended June 30		
($Cdn.)	**2011**	2010	% Change	**2011**	2010	% Change
Canada						
Heavy oil per barrel	23.91	26.37	(9)	22.50	27.30	(18)
Light oil and NGL's per barrel	21.11	27.84	(24)	17.81	26.25	(32)
Natural gas per mcf	4.00	3.07	30	3.77	1.71	121
Total per Boe	22.84	25.06	(9)	20.70	22.18	(7)
US						
Heavy oil per barrel	-	-	-	-	-	-
Light oil and NGL's per barrel	16.63	15.55	7	14.11	17.27	(18)
Natural gas per mcf	-	-	-	-	-	-
Total per Boe	14.96	14.23	5	12.42	15.94	(22)
Total						
Heavy oil per barrel	23.91	26.37	(9)	22.50	27.30	(18)
Light oil and NGL's per barrel	18.78	20.56	(9)	15.87	6,588.47	(100)
Natural gas per mcf	3.26	2.59	-	2.93	1.55	-
Operating expenses per Boe	20.34	21.48	(5)	17.99	20.46	(12)

Operating costs in Q2 2011 averaged $20.34 per Boe versus $15.83 in Q1 2011 and $21.48 in Q2 2010. The increase from Q1 2011 relates to lower production and higher field costs due to cold wet weather. Comparative quarter operating costs are down due to the sale of high operating cost properties, operational efficiencies and the addition of lower cost US production. On a year to date basis in 2011, operating costs are $17.99 per Boe down from the 2010 six month period of $20.46. The decrease over the six month period relates to 2010 field initiatives to lower field operating costs and to the sale during Q3 2010 of two high operating cost properties along with higher production from low operating cost properties in Canada at Evi and from the Bakken in North Dakota.

It is expected that as field conditions return to a more normal environment and the Company is able to access wells and low cost Bakken production is added in North Dakota, operating costs will decrease from the Q2 2011 level.

Transportation Expenses

Transportation expenses in Alberta and Saskatchewan reflect the cost of delivering production to the custody transfer point of the purchaser and in the US and include costs to truck clean oil. Generally no transportation costs to deliver production to the custody transfer point 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. For some of the Company's US wells, however, the operator, in order to receive a better price must transport the clean crude to the delivery (sales) point by truck or rail.

	Three Months Ended June 30			Six Months Ended June 30		
($Cdn.)	**2011**	2010	% Change	**2011**	2010	% Change
Canada						
Heavy oil	108,214	119,697	(10)	211,605	224,001	(6)
Light oil and NGL's	276,442	84,803	226	382,682	163,766	134
Natural gas	-	58,422	-	-	116,816	-
Total	384,656	262,922	46	594,287	504,583	18
US						
Heavy oil	-	-	-	-	-	-
Light oil and NGL's	17,079	(100,352)	117	35,511	(103,738)	134
Natural gas	-	422	-	-	899	-
Total	17,079	(99,930)	117	35,511	(102,839)	135
Total						
Heavy oil	108,214	119,697	(10)	211,605	224,001	(6)
Light oil and NGL's	293,521	(15,549)	(1,988)	418,193	60,028	597
Natural gas	-	58,844	-	-	117,715	-
Transportation expenses	**401,735**	162,992	146	**629,798**	401,744	57

Per Boe	Three Months Ended June 30			Six Months Ended June 30		
($Cdn.)	**2011**	2010	% Change	**2011**	2010	% Change
Canada						
Heavy oil per barrel	2.36	2.04	15	2.22	1.92	15
Light oil and NGL's per barrel	6.31	2.18	190	4.23	2.00	112
Natural gas per mcf	-	0.35	-	-	0.25	-
Total per Boe	3.40	2.10	62	2.55	1.83	40
US						
Heavy oil	-	-	-	-	-	-
Light oil and NGL's	0.36	(1.77)	120	0.36	(1.07)	133
Natural gas	-	0.01	-	-	0.02	-
per Boe	0.32	(1.61)	-	0.31	(0.98)	-
Total						
Heavy oil	2.36	2.04	15	2.22	1.92	15
Light oil and NGL's	3.21 -	0.16	(2,077)	2.20	0.34	556
Natural gas	-	0.30	-	-	0.23	-
Transportation expenses per Boe	2.42	0.87	178	1.82	1.05	73

Transportation costs during the current quarter increased by 146% on a dollar basis and 178% on a Boe basis to $ 401,735 and $2.42 per Boe. On a year to date basis in 2011, costs increased 57% on a dollar basis and 73% on a Boe basis to $629,798 and $1.82 per Boe. Higher costs were incurred in both Canada and the US due to additional trucking required due to wet weather and road load restrictions and due to a pipeline break at Evi, Alberta requiring the Company to truck oil to market. Natural gas transportation costs in 2010 represent costs in BC on a property sold in Q3 2010. The Company recorded an adjustment to its gas transportation costs in 2010.

Operating Netback

	Three months Ended June 30			Three months Ended June 30			
		2011			2010		Corporate
($Cdn.)	Canada	US	Corporate	Canada	US	Corporate	% Change
Heavy oil							
Revenue	**79.08**	-	**79.08**	60.51	-	60.51	**31**
Royalty	**(13.55)**	-	**(13.55)**	(7.69)	-	(7.69)	**76**
Operating	**(23.91)**	-	**(23.91)**	(26.37)	-	(26.37)	**(9)**
Transportation	**(2.36)**	-	**(2.36)**	(2.04)	-	(2.04)	**16**
Operating netback per barrel	**39.26**	-	**39.26**	24.41	-	24.41	**61**
Light oil and NGL's							
Revenue	**94.86**	**89.88**	**92.27**	70.93	70.11	70.44	**31**
Royalty	**(15.56)**	**(25.09)**	**(20.52)**	(15.45)	(17.66)	(16.75)	**23**
Operating	**(21.11)**	**(16.63)**	**(18.78)**	(27.88)	(15.53)	(20.56)	**(9)**
Transportation	**(6.31)**	**(0.36)**	**(3.21)**	(2.18)	1.77	0.16	**-**
Operating netback per barrel	**51.88**	**47.80**	**49.76**	25.42	38.69	33.29	**49**
Natural gas							
Revenue	**3.72**	**4.61**	**3.88**	4.27	4.09	4.24	**(8)**
Royalty	**(0.25)**	**(0.98)**	**(0.38)**	(0.27)	(0.76)	(0.34)	**12**
Operating	**(4.00)**	-	**(3.26)**	(3.07)		(2.59)	**26**
Transportation	-	-	-	(0.35)	(0.01)	(0.30)	**-**
Operating netback per mcf	**(0.53)**	**3.63**	**0.24**	0.58	3.32	1.01	**(76)**
Boe							
Revenue	**73.35**	**83.62**	**76.62**	55.98	66.24	59.37	**29**
Royalty	**(11.81)**	**(23.15)**	**(15.42)**	(8.74)	(16.54)	(11.32)	**36**
Operating	**(22.84)**	**(14.96)**	**(20.34)**	(25.07)	(14.21)	(21.48)	**(5)**
Transportation	**(3.40)**	**(0.32)**	**(2.42)**	(2.10)	1.61	(0.87)	**178**
Operating netback per Boe	**35.30**	**45.19**	**38.45**	20.07	37.10	25.70	**50**

The netback from heavy oil increased 61% from Q2 2010 to $39.26 per barrel for Q2 2011 due to higher prices and lower operating costs. The netback from light oil increased in Q2 2011 by 49% to $49.76 per barrel due to higher prices and lower operating costs. Natural gas netbacks declined 76% due to a lower price and various adjustments to royalties, operating and transportation expenses.

Arsenal's corporate operating netback increased 50% from Q2 2010 to $38.45 per Boe in Q2 2011 due to increased prices and slightly lower operating costs. These positive factors offset higher royalties and transportation expenses on a Boe basis.

Realized commodity contract losses reduced the operating netback by $3.01 in Q2 2011 while realized commodity contracts added $2.97 per Boe to the operating netback for Q2 2010.

	Six Months Ended June 30			Six Months Ended June 30			
	2011			2010			Corporate
	Canada	US	Corporate	Canada	US	Corporate	% Change
Heavy oil							
Revenue	**73.15**	**-**	**73.15**	64.96	-	64.96	**13**
Royalty	**(12.12)**	**-**	**(12.12)**	(8.56)	-	(8.56)	**42**
Operating	**(22.50)**	**-**	**(22.50)**	(27.30)	-	(27.30)	**(18)**
Transportation	**(2.22)**	**-**	**(2.22)**	(1.92)	-	(1.92)	**16**
Operating netback per barrel	**36.31**	**-**	**36.31**	27.18	-	27.18	**34**
Light oil and NGL's							
Revenue	**86.02**	**82.51**	**84.18**	69.76	72.46	71.23	**18**
Royalty	**(12.65)**	**(21.97)**	**(17.54)**	(12.19)	(18.20)	(15.45)	**14**
Operating	**(17.81)**	**(14.11)**	**(15.87)**	(26.25)	(17.27)	(21.38)	**(26)**
Transportation	**(4.23)**	**(0.36)**	**(2.20)**	(2.00)	1.07	(0.34)	**547**
Operating netback per barrel	**51.33**	**46.07**	**48.57**	29.32	38.06	34.06	**43**
Natural gas							
Revenue	**3.62**	**4.20**	**3.75**	4.64	4.69	4.65	**(19)**
Royalty	**(0.07)**	**(0.86)**	**(0.24)**	(0.08)	(0.54)	(0.12)	**100**
Operating	**(3.77)**	**-**	**(2.93)**	(1.70)	-	(1.55)	**89**
Transportation	**-**		**-**	(0.25)	(0.02)	(0.23)	**-**
Operating netback per mcf	**(0.22)**	**3.34**	**0.58**	2.61	4.13	2.75	**(79)**
Boe							
Revenue	**67.72**	**75.63**	**70.31**	55.93	69.05	59.55	**18**
Royalty	**(9.95)**	**(19.95)**	**(13.22)**	(7.35)	(17.05)	(10.03)	**32**
Operating	**(20.71)**	**(12.42)**	**(17.99)**	(22.18)	(15.94)	(20.46)	**(12)**
Transportation	**(2.55)**	**(0.31)**	**(1.82)**	(1.83)	0.98	(1.05)	**73**
Operating netback per Boe	**34.51**	**42.95**	**37.28**	24.57	37.04	28.01	**33**

The netback from heavy oil increased 34% for the 2011 six month period to $36.31 per barrel due primarily to lower operating costs. The netback from light oil increased in 2011 to date by 43% to $48.57 per barrel due to higher prices and lower operating costs particularly in the US as lower cost Bakken production was added to the production mix offset by higher transportation expenses. Transportation expenses for light oil increased due to trucking of crude due to an oil pipeline break at Evi, Alberta and should return to normal levels once the break is repaired. Natural gas netbacks declined 79% due to a lower price and various adjustments to royalties, operating and transportation expenses.

Arsenal’s corporate operating netback increased 33% from the 2010 six month period to $37.28 in 2011 due to increased prices and lower operating costs. These positive adjustments partially offset by higher royalties and transportation expenses on a Boe basis.

Realized commodity contract losses for the first six months of 2011 reduced the operating netback by $2.23 in 2011 while realized commodity contracts added $2.29 per Boe to the operating netback for the 2010 six month period.

General and Administrative Expenses

	Three Months Ended June 30			Six Months Ended June 30		
($Cdn.)	**2011**	2010	% Change	**2011**	2010	% Change
Gross expenditures	**1,613,977**	1,265,067	28	**3,060,383**	2,384,611	28
Overhead recovery	**(200,477)**	(124,388)	61	**(426,362)**	(334,790)	27
Capitalized overhead	**(161,000)**	(105,000)	53	**(322,000)**	(210,000)	53
Net general and administrative expense	**1,252,500**	1,035,679	21	**2,312,021**	1,839,821	26
Net general and administrative per boe	**7.54**	5.53	36	**6.68**	4.82	38

For Q2 2011, gross general and administrative expenditures were higher by $348,910 or 28% when compared to Q2 2010. On a net basis, the general and administrative expenditures increased by $216,821. For the six month period ended June 30, 2011, gross general and administrative expenditures increased by $675,772 when compared to the 2010 six month period. Net expenditures for 2011 to date increased by $472,200 when compared to 2010.

General and administrative increased due to a higher number of employees, a severance paid to a terminated employee, higher audit fees related to IFRS, higher filing fees due a higher number of shares outstanding and higher consulting fees related to increased activity.

Overhead recovery increased due to the increase in the dollar value of operated capital projects and the number of operated wells increased over the prior comparative quarter**.**

The Company capitalizes overhead directly related to exploration and development activities. For Q2 2011, the Company's capitalized overhead, excluding share based compensation, increased as a result of an additional employee whose salary and related benefits are capitalized.

On a Boe basis, general and administrative costs for the current six month period were up 38% or $1.86 per Boe to $6.68 per Boe due to higher costs as outlined above and lower production for the six month period over the comparative six month period.

Exploration and Evaluation Expenses

	Three Months Ended June 30			Six Months Ended June 30		
($Cdn.)	**2011**	2010	% Change	**2011**	2010	% Change
Exploration and evaluation	**(11,249)**	30,843	-	**4,406,155**	1,488,085	196

Under IFRS, Arsenal expenses all pre-license costs, all seismic expenditures and all dry hole costs. In 2011 to date, the Company expensed costs recorded at December 31, 2010 as "Exploration and Evaluation" assets as their status had yet to be determined. These costs related primarily to drilling costs on wells that were drilling over year end or on wells that had been drilled and required further evaluation. Subsequent to year end, it was determined that some of the wells were unproductive and therefore abandoned. Accordingly the related costs were expensed. In addition, during Q1 2011 additional expenses were incurred in the drilling of three (2.0 net) dry holes. In Q1 2011, the Company incurred seismic expenditures primarily on the Edgerton prospect that have been expensed. In Q2 2011, the Company incurred some minor additional exploration expenses and reversed an accrual made in the previous quarter

Property, Plant and Equipment Impairment

	Three Months Ended June 30			Six Months Ended June 30		
($Cdn.)	**2011**	2010	% Change	**2011**	2010	% Change
Property, plant and equipment impairment	**-**	-	-	**2,500,000**	-	-

The carrying amounts of the Company's property, plant and equipment is reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU"). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGU's reduce the carrying amounts of the other assets in the unit (group of units) on a pro rata basis.

On March 31, 2011, Arsenal completed an impairment test on its Canadian and U.S. CGU's to assess if the property, plant and equipment costs are recoverable. It was determined that the costs recorded in one CGU exceeded the estimated recoverable amount and accordingly, an impairment provision of $2.5 million was recognized. No impairment was required when the test was conducted on the Company's CGU's at June 30, 2011.

Depletion and Depreciation Expense

	Three Months Ended June 30			Six Months Ended June 30		
($Cdn.)	**2011**	2010	% Change	**2011**	2010	% Change
Depletion and depreciation	**2,599,131**	3,147,792	(17)	**5,386,925**	6,555,026	(18)
Per boe	**15.64**	16.79	(7)	**15.55**	17.18	(9)

As a result of the conversion to IFRS, the Company now depletes and depreciates its property, plant and equipment based on its total proved plus probable reserves as opposed to proved reserves that were used under previous GAAP.

On a dollar basis, depletion and depreciation declined 17% in Q2 2011 over Q2 2010 and for the current six month period, depletion and depreciation declined 18% over the 2010 six month period. These reductions were due to an 11% decline in average production in the current quarter and 9% reduction for the current six month period and to property impairments recorded under IFRS in Q4 2010 and in Q1 2011.

On a Boe basis, depletion and depreciation decreased to $15.55 per Boe for the six month 2011 period from $17.18 per Boe in the comparable 2010 period. This decrease is primarily attributable to the addition of proven and probable reserves primarily in the US and to a lesser extent to an increased weighting of lower depletion rate US production and the impairment recorded in Q4 2010 and Q1 2011.

Share-based Compensation

	Three Months Ended June 30			Six Months Ended June 30		
($Cdn.)	**2011**	2010	% Change	**2011**	2010	% Change
Share-based compensation expense	**343,297**	206,315	66	**635,197**	313,739	102

The Company uses the fair value method for valuing share based compensation. Under this method, the compensation cost attributed to stock options granted is measured at the fair value at the grant date and expensed over the vesting period with a corresponding increase in contributed surplus.

For the six months ended June 30, 2011, the Company granted 4,040,000 (June 30, 2010 – 4,280,000) options at a weighted average price of $0.68 (June 30, 2010 - $0.88) per share to a directors, officers and 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, 2011, 1,192,833 (June 30, 2010 – 171,500) options were exercised at a weighted average price of $0.42 (June 30, 2010 - $0.46) per share and 868,000 (June 30, 2010 – 676,000) options at a weighted average price of $0.90 (June 30, 2010 - $1.18) per share were forfeited or expired unexercised.

For the 2011 six month period, share-based compensation increased 102% over that recorded in the comparable 2010 period. Increases and decreases during the various reporting periods result from the number of options issued, the timing of issue and the valuation and vesting of options issued in 2009, 2010 and during 2011.

During 2011, the Company has capitalized to property plant and equipment $160,168 (June 30, 2010 - $44,097) of stock based compensation representing share based compensation relating to exploration overhead capitalized.

At June 30, 2011, the Company has 14,633,667 stock options outstanding at a weighted average price of $0.64 per share.

Finance Expenses

Financing expenses 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 and accretion of the decommissioning obligations. Accretion is the increase or decrease in the reporting period in the present value of the Company's decommissioning obligation, which is discounted using a risk free interest factor of 3.5%.

Finance expense	**Three Months Ended June 30**			**Six Months Ended June 30**		
($Cdn.)	**2011**	2010	% Change	**2011**	2010	% Change
Cash						
Interest on bank loan and other charges	**323,380**	357,052	(9)	**450,351**	615,707	(27)
Non-cash						
Acretion of decomissioning obligations	**169,735**	208,831	(19)	**341,584**	417,852	(18)
Finance expenses	**493,115**	**565,883**	(13)	**791,935**	**1,033,559**	(23)

Per Boe	**Three Months Ended June 30**			**Six Months Ended June 30**		
($Cdn.)	**2011**	**2010**	% Change	**2011**	**2010**	% Change
Cash	**1.95**	**1.90**	2	**1.30**	**1.61**	(19)
Non-cash	**1.02**	**1.11**	(8)	**0.99**	**1.10**	(10)
Total	**2.97**	**3.02**	(2)	**2.29**	**2.71**	(16)

Interest on bank loan and other charges decreased 27% in the six month 2011 period from the comparative 2010 period. This reduction relates to lower average borrowings during the comparative periods offset by higher interest rates. The equity financing completed in February 2011 eliminated debt for part of the period while capital spending, in excess of cash flow, increased borrowing. The average borrowing balance for Q2 2011 was $3.1 million versus $5.7 million for Q1 2011 and $18.8 million for Q2 2010. On a year to date basis, the average borrowings for the six month 2011 period was 4.4 million versus $18.9 million for the 2010 comparative period.

In June 2011 as a result of a review of the Company's independent engineering report, the Company's credit facility was syndicated and increased to $60.0 million at rates ranging from Canadian or US prime plus 1.00% to 2.50% on prime based loans and from the base rate plus 2.00% to 3.50% on bankers' acceptances and on Libor based loans.

With the change of the credit facility and the increase in the Company's credit facility from $40.0 million to $60.0 million, the Company incurred higher bank and legal fees related to the credit facility than the fees paid in 2010. In addition, the higher prime rate of interest this year offset any further decrease in the Company's borrowing costs to date in 2011.

Income Tax Expense

	Three Months Ended June 30			Six Months Ended June 30		
($Cdn.)	**2011**	**2010**	% Change	**2011**	2010	% Change
Income tax expense (reduction)	**1,013,594**	558,722	81	**762,544**	1,095,490	(30)

For the six months ended June 30, 2011, the Company recorded income tax expense of $762,544. This income tax expense consists of income tax expense for the US operations of $939,781 and a future income tax reduction of $177,237 relating to Canadian operations. For the current six month period, earnings in the US resulted in the income tax expense and expenses relating to exploration and evaluation, property, plant and equipment impairment and depletion and depreciation charges in Canada for the six month period were primarily responsible for the reduction of future income taxes.

At June 30, 2011, a deferred income tax liability related to US operations of $2,366,773 million has been recorded down slightly from $1.5 million recorded at December 31, 2010. In Canada, a deferred tax asset of $1.8 million has been recorded as at June 30, 2011 unchanged from December 31, 2010.

Arsenal does not expect to pay current tax in Canada or in the US in 2011 or 2012 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.

Funds from Operations and Loss and Comprehensive Loss

Funds from Operations	**Three Months Ended June 30**			**Six Months Ended June 30**		
($Cdn.)	**2011**	2010	% Change	**2011**	2010	% Change
Cash provided by operations	**4,096,938**	3,581,654	14	**8,364,894**	7,080,205	18
Seismic expenses	**3,793**	30,844		**735,841**	1,488,085	
Decommissioning obligations settled	**201,036**	394,940	(49)	**306,667**	628,552	(51)
Funds from operations	**4,301,767**	4,007,438	7	**9,407,402**	9,196,842	2

Funds from operations (defined as cash provided by operating activities before exploration and evaluation expenses and settlement of decommissioning obligations) for the six month period ended June 30, 2011 totaled $9.4 million or $0.06 per share basic and diluted compared to $9.2 million or $0.07 per share basic and diluted for the six month comparative period of 2010.

For Q2 2011, funds from operations totaled $4.3 million or $0.03 per share basic and diluted versus $5.1 million or $0.03 per share basic and diluted in Q1 2011 and $4.0 million or $0.03 per share basic and diluted in Q2 2010.

Funds from operations for 2011 were reduced by lower production due to severe weather and lease flooding, higher transportation expenses due to trucking required due to pipeline breaks and realized losses on commodity contracts of $500,260 in Q2 2011 and $271,011 in Q1 2011 versus realized gains of $557,002 in Q2 2010 and $318,358 in Q1 2010.

For the six month period ended June 30, 2011, the Company reported a loss of $4.9 million ($0.03 per share basic and diluted) versus a profit of $505,623 ($nil per share basic and diluted) for the comparative six month period in 2010.

The Company recorded income for Q2 2011 of $3.0 million ($0.02 per share basic and diluted) versus income of $574,690 ($nil per share basic and diluted) in Q2 2010. The Q2 2011 income was related to higher commodity prices, commodity contract gains, lower depletion and depreciation expenses, operating and transportation expenses and financing costs offset partially by higher royalties. The Company had no exploration and evaluation expenses or property, plant and equipment impairment in the quarter.

The Company's comprehensive loss includes gains and loss on translation of foreign operations. During 2011, because of the strengthening of the Canadian dollar over the quarter, the Company recorded a loss of $210,421 on the translation of the US operations. The Company's loss and comprehensive loss therefore for the six month period ended June 30, 2011 totaled $5.1 million versus a net income and comprehensive income of $481,723 for the six months ended June 30, 2010.

Summary of Quarterly Results

	IFRS						Former Canadian GAAP			
	2011		2010				2009			
($Cdn.)	**Q2**	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Oil and gas revenue	**12,729,872**	11,619,144	11,250,143	9,701,018	11,128,046	11,586,513	10,759,516	8,975,159	9,383,636	7,823,551
Net income (loss)	**3,011,927**	(7,939,855)	(6,443,517)	(353,424)	574,690	(69,068)	(2,845,384)	(1,897,761)	(3,235,660)	(3,071,711)
Per share - basic	**0.02**	(0.05)	(0.05)	(0.00)	0.00	(0.00)	(0.03)	(0.02)	(0.03)	(0.03)
Per share - diluted	**0.02**	(0.05)	(0.05)	(0.00)	0.00	(0.00)	(0.03)	(0.02)	(0.03)	(0.03)
Funds from operations	**4,301,767**	5,105,635	5,041,954	3,633,712	4,007,438	5,189,404	3,471,910	2,887,826	2,031,722	10,315,270
Per share - basic	**0.03**	0.03	0.04	0.03	0.03	0.04	0.03	0.03	0.02	0.10
Per share - diluted	**0.03**	0.03	0.04	0.03	0.03	0.04	0.03	0.03	0.02	0.10
Total assets	**97,040,147**	101,005,848	92,595,917	87,035,956	92,271,525	92,871,950	116,880,416	118,244,383	122,486,146	131,477,316
Total debt (1)	**9,931,680**	6,871,378	18,787,775	15,061,052	19,886,286	20,318,893	28,739,421	33,285,548	37,104,499	40,124,195
Shares outstanding	**161,761,062**	163,314,306	140,812,472	133,734,472	134,195,472	134,773,390	120,461,890	109,961,890	101,249,646	101,249,646

(1) Includes bank debt, working capital and convertible debentures outstanding but excludes risk management contracts

Arsenal's quarterly results have fluctuated significantly in the past quarters due to a variety of factors that include the conversion to IFRS at January 1, 2010, commodity price and production swings, the timing of drilling and completions particularly in the US and in Alberta at Evi and the rationalization of properties and operating costs. Arsenal will focus on properties with a long reserve life, high netbacks in areas where the Company has a strategic, technical or financial advantage. Quarterly results therefore will continue to fluctuate somewhat and will depend on the results of exploration and evaluation activities, property dispositions, the movement in commodity prices particularly for oil, the differentials in heavy oil, the transportation discount in the US 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 which should 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, 2011 with a fixed term are as follows:

($Cdn.)	2011	2012	2013	2014	2014
Flow-through share commitments	**1,500,000**	-	-	-	-
Lease of office premises	**247,376**	288,605	-	-	-
Equipment lease	**24,258**	48,516	40,430	-	-
Total	**1,771,634**	337,121	40,430	-	-

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 agreements.

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 $167,858 for 2011 and by $97,917 for 2012.

The Company has no off balance sheet arrangements other than operating leases for office space and equipment as disclosed above**.**

In order to ensure rig availability for the Company's operated wells in the state of North Dakota, the Company has committed to moving a rig and to utilize the rig for a 200 day term commencing approximately on November 15, 2010. The Company will charge joint venture partners with their proportionate share of these costs. The Company estimates, that based on rig mobilization costs and drilling day rates, its commitment to be approximately $750,000.

Segmented Statement of Operations by Country

Six Months Ended June 30, 2011	Canada	United States	Total Company
Revenue			
Petroleum and natural gas	15,779,513	8,569,503	**24,349,016**
Royalties	(2,318,222)	(2,260,634)	**(4,578,856)**
	13,461,291	6,308,869	**19,770,160**
Realized gain (loss) on risk management contracts	(319,241)	(452,030)	**(771,271)**
Unrealized gain (loss) on risk management contracts	(149,541)	42,077	**(107,464)**
Other income	6,053	318	**6,371**
	12,998,562	5,899,234	**18,897,796**
Expenses			
Operating	4,824,505	1,406,833	**6,231,338**
Transportation	594,287	35,511	**629,798**
General and administrative	1,546,298	765,723	**2,312,021**
Exploration and evaluation	4,406,155	-	**4,406,155**
Property, plant and equipment impairment	2,500,000	-	**2,500,000**
Depletion and depreciation	4,595,164	791,761	**5,386,925**
Share-based compensation	635,197	-	**635,197**
Foreign exchange loss	200,953	-	**200,953**
Gain on property sale	(31,141)	-	**(31,141)**
	19,271,418	2,999,828	**22,271,246**
Finance expenses	451,223	340,712	**791,935**
Loss before income taxes	(6,724,079)	2,558,694	**(4,165,385)**
Income taxes			
Deferred tax (reduction)	(177,237)	939,781	**762,544**
	(177,237)	939,781	**762,544**
Net loss	(6,546,842)	1,618,913	**(4,927,929)**

Six Months Ended June 30, 2010	Canada	United States	Total Company
Revenue			
Petroleum and natural gas	15,448,102	7,266,457	**22,714,559**
Royalties	(2,030,041)	(1,795,079)	**(3,825,120)**
	13,418,061	5,471,378	**18,889,439**
Realized gain (loss) on risk management contracts	985,469	(110,109)	**875,360**
Unrealized gain (loss) on risk management contracts	1,231,290	(39,442)	**1,191,848**
Other income	3,793	755	**4,548**
	15,638,613	5,322,582	**20,961,195**
Expenses			
Operating	6,126,924	1,677,524	**7,804,448**
Transportation	504,582	(102,838)	**401,744**
General and administrative	1,169,466	670,355	**1,839,821**
Exploration and evaluation	1,434,654	53,431	**1,488,085**
Property, plant and equipment impairment	-	-	**-**
Depletion and depreciation	5,747,001	808,025	**6,555,026**
Share-based compensation	313,739	-	**313,739**
Foreign exchange gain	(76,340)	0	**(76,340)**
	15,220,026	3,106,497	**18,326,523**
Finance expenses	802,441	231,118	**1,033,559**
Income (loss) before income taxes	(383,854)	1,984,967	**1,601,113**
Income taxes			
Deferred tax (reduction)	155,471	940,019	**1,095,490**
	155,471	940,019	**1,095,490**
Net income (loss)	(539,325)	1,044,948	**505,623**

Select Financial Information by Country

For Six Months Ended June 30, 2011 ($ Cdn.)	Canada	U.S	Total
Oil and gas revenue	15,779,513	8,569,503	24,349,016
Income (loss) before income taxes	(6,724,079)	2,558,694	(4,165,385)
Operating income	8,042,499	4,866,525	12,909,024
Exploration and evaluation assets (as at June 30, 2011)	6,413,055	-	6,413,055
Property, plant and equipment (as at June 30, 2011)	53,812,079	25,954,322	79,766,401
Capital expenditures	2,673,669	9,029,334	11,703,003
Exploration and evaluation expenditures	6,552,488	-	6,552,488
Property dispositions	(598,509)	-	(598,509)

For Six Months Ended June 30, 2010 ($ Cdn.)	Canada	U.S	Total
Oil and gas revenue	15,448,102	7,266,457	22,714,559
Income (loss) before income taxes	(853,901)	2,455,014	1,601,113
Operating income	6,786,555	3,896,692	10,683,247
Exploration and evaluation assets (as at June 30, 2010)	2,336,342	-	2,336,342
Property, plant and equipment (as at June 30, 2010)	65,328,656	12,960,356	78,289,012
Capital expenditures	2,494,455	2,944,313	5,438,768
Exploration and evaluation expenditures	3,855,862	53,431	3,909,293
Property dispositions	(214,831)	-	(214,831)

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 and what, if any, additional initiatives may need to be implemented.

The Company considers shareholder’s equity, bank loan and working capital (excess or deficiency) 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, or reviewing the advisability of fixing, interest rates and commodity prices on all or a portion of the Company’s debt and 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 ratio. Debt includes bank borrowings, plus or minus working capital and excludes decommissioning obligations and risk management contracts (whether an asset or an obligation). Annualized funds flow is calculated as cash flow from operations before changes in non-cash working capital, decommissioning obligations settled and exploration and evaluation expenses from the Company’s most recent quarter multiplied by four adjusted, if required, by increasing or decreasing commodity price expectations, future production profiles, the Company’s risk management position and other non-recurring items. The Company’s goal is to target this ratio at 1.00 : 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 ratio represents the time period it would take to pay off the debt if no further capital expenditures were incurred and if funds from operations remained constant. 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, 2011, the Company's net debt to annualized funds flow ratio was 0.58 : 1 and its debt to equity ratio was 0.18 : 1. Conversion to IFRS reduced equity by approximately $28.1 million primarily as a result of the fair value assessment by CGU and the adjustment to decommissioning obligations. An equity issue generating net proceeds of approximately $19.8 million in February 2011 increased equity and reduced debt improving the debt to annualized funds flow ratio and the debt to equity ratio at year end. At June 30, 2011, both the net debt to annualized funds flow ratio and the debt to equity ratio are lower than the target range as established in management's strategic goals and guidelines.

($Cdn.)	**June 30, 2011**
Bank loan	6,671,904
Working capital deficiency *(excluding risk management contracts)*	3,259,776
Total debt	9,931,680
Annualized funds from operations	17,207,068
Net debt to annualized funds flow ratio	0.58
Shareholders' Equity	54,652,380
Debt to equity	0.18

The Company expects to focus its 2011 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, Provost and Edgerton all in Alberta.

Key factors that will determine if the Company will be able to remain within its established guidelines are production rates from drilling, commodity (particularly crude) prices, interest and foreign exchange rates and the magnitude and timing of capital expenditures particularly as they relate to acquisitions and drilling and completions in North Dakota. In 2010, Company maintained a portion of its debt in US dollars as a hedge against the foreign exchange fluctuations affecting certain elements of its business. The Company reduced its US dollar borrowings to nil in February 2011 but has recently borrowed US dollars and at June 30, 2011, held $3,050,000 of its debt was denominated in US dollars.

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

At June 30, 2011, the Company's credit facility was reviewed, syndicated and increased from $40.0 million to $60.0 million based on the independent engineering report as at December 31, 2010. The credit facility is available in

Canadian and/or US dollar prime loans or in Bankers Acceptances' and/or Libor borrowings. Interest on the Company's credit facility is at rates ranging from Canadian or US prime plus 1.00% to 2.50% on prime based loans and from the base rate plus 2.00% to 3.50% on Bankers Acceptances' and on Libor based loans. The interest rate is set based on the Company's debt, as calculated for this purpose to include bank loan plus working capital (excess or deficiency), outstanding letters of credit and other miscellaneous items but excludes decommissioning obligations and risk management contracts (whether an asset or an obligation) to trailing funds flow ratio (funds flow for the last two quarters annualized) adjusted for any unusual or non-recurring items.

The credit facility has a revolving period of 364 days plus one year and is extendible annually. If not extended, the credit facility will automatically convert to a one year non-revolving term loan and all obligations under the credit facility shall be repaid or paid at the end of the one year period.

The credit facility is secured by an unlimited liability guarantee to the lenders, a ISDA Master Agreement, a demand debenture in the amount of $300,000,000 granting a first priority security interest over all present and after acquired personal property and a first floating charge over all present and after acquired petroleum and natural gas interests and mortgages creating specific fixed charges on some of the oil and gas properties of the Company in North Dakota.

The credit facility is also subject to certain positive and negative covenants including a covenant not to dispose of assets or property having a fair aggregate value not exceeding 5% of the borrowing base with no adjustment to the borrowing base.

At June 30, 2011, debt under the credit facility amounted to $6,671,904 and includes $3,050,000 of US dollar denominated borrowings.

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 adjusted working capital ratio (as defined in the agreement to include the unutilized portion of the facility and to exclude the value of any risk management contracts) to fall to below 1 : 1.

At June 30, 2011, the Company was in compliance with this covenant.

Liquidity

Crude prices have improved over the past year or so and until just recently had stabilized in the $90.00 - $100.00 US range. Natural gas prices have fallen over the past year or so and seem to have stabilized in the $3.25 Canadian $4.00 US range. In addition, access to equity markets has been restored. Increased commodity prices have led to an improvement in the Company's funds from operations and its access to capital. In February 2011, the Company completed an equity issue for net proceeds of $19.8 million. The Company has available the financial resources necessary to undertake an aggressive 2011 capital expenditure program that is expected to be higher than its 2011 projected funds from operations. Even with an aggressive capital program, it is expected that the Company will remain within an industry acceptable level of debt and within its targeted range of its debt to annualized funds flow from operations ratio of 1.00 : 1. 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 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 2011 and 2012 capital program and to ensure positive returns from the Company's capital development and acquisition program, the Company has in place certain commodity price contracts. At June 30, 2011 the Company had eight commodity contracts in place with the fair value at June 30, 2011 as follows:

($Cdn.)				
Commodity Sold	Volume Sold	Remaining Term	Price	Fair Value
Oil	100 bbl per day	July 1, 2011 - Dec 31, 2011	85.50 per bbl	(150,502)
Oil	100 bbl per day	July 1, 2011 - Dec 31, 2012	89.50 per bbl	(77,234)
Oil	100 bbl per day	July 1, 2011 - Dec 31, 2012	87.05 per bbl	(497,593)
Oil	100 bbl per day	July 1, 2011 - Dec 31, 2011	88.00 per bbl	(104,710)
Oil	100 bbl per day	Jan 1, 2012 - Dec 31, 2012	90.65 per bbl	(245,896)
Oil	100 bbl per day	July 1, 2011 - Dec 31, 2011	93.30 per bbl	(7,629)
Oil	300 bbl per day	Jan 1, 2012 - Dec 31, 2012	95.15 per bbl	(251,747)
Oil	200 bbl per day	July 1, 2011 - Dec 31, 2013	96.33 per bbl	(192,666)
				(1,527,977)

In August 2011, the Company entered into an additional crude oil commodity price contract as follows:

($Cdn.)			
Commodity Sold	Volume Sold	Term	Pricing
Oil	300 bbl per day	January 1, 2013 - Dec 31, 2013	95.10 per bbl

In August 2011, the Company monetized all of the above commodity contracts for proceeds of $4.5 million.

Share Capital

In February 2011, the Company, pursuant to a short for prospectus, issued 22,158,500 common shares at $0.95 per share for gross proceeds of $21.1 million (net proceeds of $19.8 million).

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. Under the bid, the Company acquired 2,974,918 common shares under the bid at an average price of approximately $0.80 per share plus acquisition costs.

On June 16, 2011, the Company announced its intention to make a normal course issuer bid (“NCIB”) that commenced June 20, 2011 and ends June 19, 2012. A total of 8,128,724 common shares may be acquired under the bid representing 5% of the common shares outstanding as of June 14, 2011. To date, the Company has purchased 831,743 common shares at an average cost of $0.65 per share plus expenses.

Common shares

	Quarter Ended June 30, 2011	Period Ended August 9, 2011
Balance - beginning of period	**140,812,472**	**140,812,472**
Issued under prospectus offering	**22,158,500**	**22,158,500**
Issued on exercise of options	**1,192,833**	**1,192,833**
Purchases under normal course innuer bid	**(2,402,743)**	**(2,402,743)**
Balance - end of period	**161,761,062**	**161,761,062**

Options

	Quarter Ended June 30, 2011	Period Ended August 9, 2011
Balance - beginning of period	**12,754,500**	**12,754,500**
Exercise of options	**(1,192,833)**	**(1,192,833)**
Options issued	**4,040,000**	**4,540,000**
Options forfeited or expired	**(868,000)**	**(1,557,997)**
Balance - end of period	**14,733,667**	**14,543,670**

Related Party Transactions

An officer of the Company is a partner in a law firm that provides legal services to the Company. During the first six months in 2011, the Company incurred a total of $145,198 (2010 - $ 132,812) for legal fees and disbursements. As at June 30, 2011, accounts payable include $30,000 (December 31, 2010 - $35,000) relating to these payments.

A Director of the Company is a partner in a law firm that provides legal services to the Company. During the first three months in 2011, the Company recorded a total of $2,362 (2010 - $3,484) for legal fees and disbursements. As at June 30, 2011 accounts payable include $nil (December 31, 2010 - $nil) relating to these payments.

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

Exploration and Evaluation

($ Cdn.)	Three Months Ended March 31 2011	Three Months Ended June 30 2011	Six Months Ended June 30 2011
Land	1,522,821	1,747,215	3,270,036
Drilling and completions	3,343,643	(61,191)	3,282,452
Total Exploration and Evaluation Expenditures	4,866,464	**1,686,024**	**6,552,488**

Property, Plant and Equipment

($ Cdn.)	Three Months Ended March 31 2011	Three Months Ended June 30 2011	Six Months Ended June 30 2011
Land	475,300	9,593	484,893
Drilling and completions	5,541,670	3,560,597	9,102,267
Capitalized general and administrative	250,999	231,169	482,168
Production equipment, facilities and tie-ins	1,106,297	683,762	1,790,059
Other	282,432	3,784	286,216
Total property plant and equipment additions	7,656,698	4,488,905	12,145,603
Non-cash additions	(372,421)	(70,179)	(442,600)
Total Property, Plant and Equipment Expenditure	7,284,277	**4,418,726**	**11,703,003**

Property Dispositions

($ Cdn.)	Three Months Ended March 31 2011	Three Months Ended June 30 2011	Six Months Ended June 30 2011
Total Property Dispositions	(472,591)	**(125,918)**	**(598,509)**

Seismic

($ Cdn.)	Three Months Ended March 31 2011	Three Months Ended June 30 2011	Six Months Ended June 30 2011
Total Seismic	732,048	**3,793**	**735,841**

Capital expenditures for the first six months of 2011 totaled $18.3 million increasing 95% over $9.3 million expended during the first half of 2010. During 2011, the Company participated in the drilling of 5 gross (3.03 net) wells. Three (2.0 net) of the wells were dry and abandoned and written off to exploration and evaluation expense. At Stanley, North Dakota, the Company completed drilling and rig released the two (1.4 net) Company operated wells, participated at a 3.13% working interest in a partner operated well and completed a partner operated well drilled in Q4 2010. During Q2 2011, completion operations commenced on the two Company operated wells in North Dakota. At Evi, Alberta four wells were drilled, three resulted in dry holes and one (1.00 net well) was completed and is productive.

During the first six months of 2011, the Company closed the sale of three noncore low netback properties netting $598,509.

Decommissioning Obligations

The Company's decommissioning obligations represents the Company's accounting estimate of the present value of 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, 2011, the Company has recorded a decommissioning obligation of $19.4 million (December 31, 2010 - $19.7 million).

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligations associated with the retirement of oil and gas properties:

($Cdn.)	**Six Months Ended June 30, 2011**	Year Ended December 31, 2010
Balance at beginning of period	**19,667,331**	21,182,129
Liabilities settled	**(306,667)**	(1,083,837)
Liabilities acquired	**-**	20,216
Liabilities dosposed of	**(415,898)**	(2,726,393)
Liabilities incurred	**282,432**	683,760
Change in estimated future cash outflows	**-**	1,109,054
Foreign currency translation	**(154,196)**	(273,639)
Accretion expense	**341,584**	756,041
Balance at end of period	**19,414,586**	19,667,331

The total undiscounted amount of estimated cash flows required to settle the obligation is $29.7 million, which has been discounted for in the financial statements using a risk free rate of 3.5% and an inflation factor of 1.5%.

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 several risk factors and uncertainties. For a detailed discussion of the risks and uncertainties associates with the Company's business and operations, refer to Arsenal's Annual Information Form, dated March 22, 2011 and the MD&A for the year ended December 31, 2010 each of which may be accessed on SEDAR at www.sedar.com.

Critical Accounting Estimates and Policies

The significant accounting policies used by the Company are outlined in note 3 to the interim consolidated financial statements for the three and six months ended June 30, 2011 and 2010. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported statement 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 estimates that differ materially from current estimates.

Critical Accounting Estimates

Management is often required to make judgments, assumptions and estimates in the application if IFRS that may have a significant impact on the financial results of the Company. The preparation of financial information in accordance with IFRS requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. The following is a summary of key areas where critical accounting estimates are made:

Financial statement item	Critical accounting estimates
Depletion and depreciation expense	Quantities of proved and probable reserves; future development costs related to proved and probable reserves; residual values
Impairment of property, plant and equipment	Future commodity prices; volumes of production and reserves; operating, capital and other costs; discount rates
Exploration and evaluation assets	Likelihood of future benefits before proved or probable reserves have been established
Decommissioning liabilities and related accretion expense	Timing and amount of cash flows required to settle the liabilities; risk free interest rate
Share-based compensation expense	Expected life of stock options; expected forfeiture rate; expected share price volatility; risk-free interest rate
Fair value of derivative instruments	Amount and timing of future cash flows; discount rates
Deferred income taxes	Interpretations of current tax legislation; future taxable income; timing of reversal of temporary difference and related tax rates in effect

Change in Accounting Policies

International Financial Reporting Standards ("IFRS")

On January 1, 2011, IFRS became the generally accepted accounting principles in Canada for profit-oriented publicly accountable enterprises. Arsenal adopted IFRS for financial reporting purposes using a transition date of January 1, 2010. The adoption of IFRS required restatement of comparative amounts reported by the Company for the three and six months ended June 30, 2010. As a result, the Company's financial results for the second quarter ended June 30, 2010 and comparative periods are reported under IFRS while selected historical data continues to be reported under former Canadian GAAP.

The adoption of IFRS did not have a material impact on net cash flows. It did have a material impact on certain accounting policies and Arsenal's reported financial position and results of operations. The most significant areas of impact for Arsenal include property plant and equipment, asset retirement obligations, accounting for share-based payments and deferred taxes (formerly "future taxes").

IFRS 1: First Time Adoption of IFRS 1

The adoption of IFRS requires the application of IFRS 1 – First-time Adoption of International Financial Reporting Standards ("IFRS1") which provides guidance for the initial adoption of IFRS. IFRS 1 generally requires that an entity retrospectively apply IFRS policies in its entirety effective at the end of its first IFRS reporting period except where specific IFRS 1 optional and mandatory exemptions permit an alternative treatment. Arsenal applied the following optional exemptions to its opening IFRS statement of financial position of January 1, 2010.

Property, Plant and Equipment

The Company elected to apply the IFRS 1 exemption to deem the opening net book value of its property, plant and equipment recorded under the full cost oil and natural gas accounting pool under Canadian GAAP at the date of transition (January 1, 2010) as the deemed cost for its property, plant and equipment under IFRS. The Company had not recognized any exploration and evaluation assets under Canadian GAAP and accordingly did not recognize any exploration and evaluation assets under IFRS. The net book value was allocated to producing and development assets based on proven plus probable reserves. The Company was required to conduct an impairment test, under IFRS standards at the transition date.

Decommissioning Obligations

In accordance with IFRS 1, if the exemption for full cost oil and natural gas accounting is taken, then the decommissioning obligations must be remeasured at the date of transition with any difference charged to deficit.

Share-based Payments

As provided in IFRS 1, Arsenal elected not to apply IFRS 2 - Share-Based Payments for share-based payments which vested before January 1, 2010.

IFRS allows certain other optional exemptions; however, such exemptions were assessed to be either not applicable or not significant to Arsenal's adoption of IFRS.

The following discussion uses the IFRS standards and interpretations currently issued and expected to be in effect at the end of Arsenal's first IFRS reporting period of December 31, 2011.

Impacts of IFRS on Accounting Policies

The adoption of IFRS results in accounting policies that are significantly different from those under former Canadian GAAP:

Exploration and Evaluation Expenditures

Under Canadian GAAP, Arsenal capitalized these costs and depleted such costs within the full cost pool. Under IFRS, costs including the costs of acquiring leases and licenses, directly attributable general and administrative costs and drilling costs on wells not yet fully evaluated, are capitalized as exploration and evaluation assets according to the nature of the assets acquired. The costs are accumulated in cost centers, by field or in exploration areas pending determination of technical feasibility and commercial viability. Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are allocated to cash-generating units.

Under IFRS, pre-license costs, seismic costs and all dry holes are expensed as incurred.

Property, Plant and Equipment:

Development Costs

Under previous Canadian GAAP, the Company applied full cost accounting in which all costs directly associated with the acquisition of, the exploration for, and the development of crude oil and natural gas reserves were capitalized on a country-by-country cost centre basis. Costs accumulated within each country cost centre were depleted using the unit-of production method based on total proved reserves determined using estimated future prices and costs. Capitalized costs were subject to a two part ceiling test using undiscounted proven reserves and discounted (based on a risk free discount rate) of proven and probable reserves. On transition to IFRS, Arsenal was required to adopt new accounting policies for pre-exploration costs, exploration and evaluation costs and development costs.

Under IFRS, development costs are expenditures incurred at an area or property level where technical and commercial feasibility have been determined. These costs are capitalized and accumulated in cash generating units (CGU"S). The Company determined that it had seven CGU and costs were allocated to CGU's based on reserve volumes. Development costs are depleted on a unit-of-production basis over an area or on a CGU level and are subject to an impairment test. Arsenal calculates depletion on an area basis using proved and probable reserves.

Property Sales

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

Impairment:

Under IFRS, producing and development assets are grouped into CGU's based on their ability to generate cash inflows independent from other assets or groups of assets. Impairment must be calculated at the CGU level, instead of the country cost center used under former Canadian GAAP, and is recognized if the carrying value of a CGU exceeds the greater of its value in use or fair market value less costs to sell. Assets are assessed for impairment when indicators suggest the possibility of impairment and at least at the end of each reporting period. Impairment losses are reversed when there is an increase in the recoverable amount.

Share-based Payments:

Both previous Canadian GAAP and IFRS use the fair value method for accounting purposes. Under Canadian GAAP, share based expense was recognized on a straight line basis. IFRS requires the Company to estimate the number of options expected to vest when a grant of equity instruments do not vest immediately. In addition, each vesting installment is to be treated as a separate arrangement. Share-based payments are expensed using graded vesting and 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.

Decommissioning Obligations

Under previous Canadian GAAP, the discount rate is the credit adjusted risk-free rate. Under Canadian GAAP, any change in the discount rate is applied to the prospective additions to the obligation. IFRS uses the risk-free rate. Under IFRS any change in the discount rate must be applied to the entire obligation liability. IFRS 1 requires that an entity adopting the full cost accounting deemed cost exemption must also measure the decommissioning liability associated with property, plant and equipment as at the date of transition to IFRS with any impact recorded to deficit on adoption.

Flow-Through Shares

Under previous Canadian GAAP, the obligation to incur qualifying expenditures from the issuance of flow-through shares is a disclosure item and the future tax liability associated with the renouncement of tax deductions from the issuance of flow-through shares was recorded as a reduction in share capital at the time of renouncement. Under IFRS, the premium received on the flow-through shares, being the difference in price over a common share with no tax attributes, is recognized on the statement of financial position. As expenditures are incurred the deferred tax liability associated with the renounced tax deductions are recognized through profit and loss along with a pro-rata portion of the deferred premium.

Deferred Taxes

Under previous Canadian GAAP, deferred tax assets and liabilities were presented according to the classification of the underlying asset or liability that created the difference in the deferred tax amount. Under IFRS, all deferred tax assets and liabilities are classified as long-term.

Impact of IFRS on Financial Position and Results of Operations

Note 17 to the June 30, 2011 unaudited condensed interim consolidated financial statements provides a detailed reconciliation of the adjustments arising from the conversion to IFRS in the comparative 2010 amounts. The significant differences were:

Exploration and Evaluation assets – Under IFRS 6, Arsenal reclassified $2.3 million from property, plant and equipment to exploration and evaluation at June 30, 2010 and $6.4 million at December 31, 2010. No costs were reclassified upon transition.

Property, Plant and Equipment - Under IFRS, impairment tests for property, plant and equipment are performed at a CGU level as opposed to the entire Company’s property, plant and equipment balance being subjected to a full cost ceiling test under previous Canadian GAAP. Impairment is recognized if the carrying value exceeds the recoverable amount for a CGU. The recoverable amount is determined using the greater of the fair value less costs to sell based on discounted future cash flows of proved plus probable reserves using forecast prices and costs, and the value in use. Upon transition to IFRS, Arsenal recognized $30.3 million impairment which was recognized in the opening deficit. As a result of decreased forward natural gas prices and a downward revision of reserves in a certain CGU, Arsenal recognized an impairment of $5.9 million for the year ended December 31, 2010. This resulted in a reduction of property, plant and equipment with the offset charged to property, plant and equipment impairment in the consolidated statement of loss.

On transition to IFRS Arsenal elected to expense all dry holes, seismic expenditures and lease rentals resulting in $2.2 million of dry holes and seismic expenditures being charged to exploration and evaluation expenditures in 2010 (June 30, 2010 - $1.5 million) and $423,135 of lease rentals being charged to operating expenses in 2010 (June 30, 2010 - $203,211).

Depletion and Depreciation Expense – Under IFRS, Arsenal has chosen to calculate depletion expense based on proved plus probable reserves as opposed to proved reserves under previous GAAP. This has resulted in a reduction of depletion and depreciation expense of approximately $15.0 million in 2010 (June 30, 2010 - $7.8 million).

Decommissioning Obligations – Under previous GAAP, Arsenal's decommissioning obligations at December 31, 2009 were discounted based on a credit adjusted risk-free rate of 8%. Under IFRS, the Company is required to revalue its obligation at each balance sheet date using a current liability-specific discount rate. At transition, Arsenal revalued the obligation based on a risk-free rate of 4% resulting in a $7.1 million increase to the liability with the offset charged to deficit. A further change in the discount rate at September 30, 2010 resulted in a revaluation to increase the liability by $1.1 million. As a result of the change in the discount rate applied, accretion of decommissioning obligation expense decreased by $270,045 for the year ended December 31, 2010 (June 30, 2010 - $139,518).

Flow-Through Share Obligations – Under previous GAAP, the deferred tax liability associated with the renouncement of tax deductions from the issuance of flow through shares was recorded as a reduction in share capital at the time of renouncement. Under IFRS, the difference between the deferred tax liability associated with the renouncement of the tax deductions and the premium price received on the issuance of flow through shares over the market value of the Company's common shares at the time of issue is recorded as a deferred tax expense. This deferred tax expense represents the net loss on the distribution of the tax deductions to investors. The transitional adjustment resulted in an increase of $5.5 million June 30, 2010 - $6.8 million and December 31, 2010 - $6.8 million) to share capital with a resulting offset being charged to deficit.

For the year ended December 31, 2010, a deferred tax expense of $1.1 million (June 30, 2010 - $1.1 million) was recognized as a result of changes in the temporary difference between the net book value and the tax basis of the assets and liabilities.

Share Based Compensation – Under previous GAAP, Arsenal expensed stock-based compensation on a straight-line basis. Under IFRS, share-based payments are expensed based on a graded vesting schedule. Arsenal also incorporated a forfeiture multiplier rather than accounting for forfeitures as they occur as currently practiced under previous GAAP. The adjustment to contributed surplus to account for the graded vesting and forfeitures was an increase of $189,946 with the offset being charged to deficit. This resulted in $34,466 change for the six months ended June 30, 2010 and a $233,588 increase to share-based compensation expense for the year ended December 31, 2010.

Divestitures – Under previous GAAP, proceeds from divestitures were deducted from the full cost pool without recognition of a gain or loss unless the divestiture resulted in a change in the depletion rate of 20% or greater in which case, a gain or loss was recorded. Under IFRS, gains and losses are recorded on divestitures and are calculated as the difference between the proceeds and the net book value of the asset disposed of.

For the year ended December 31, 2010, the Company recorded a $1.2 million (June 30, 2010 - $nil) gain on disposition of oil and gas properties for IFRS as compared to nil under previous GAAP. During the third quarter of 2010, the Company disposed of oil and gas properties in the British Columbia and Wildmere with a combined net book value of $6.8 million.

Cumulative Translation Losses – Upon transition to IFRS, Arsenal elected to reset cumulative translation losses to zero with the adjustment going through opening deficit.

Cash Flow Statement – Upon transition to IFRS, there were no significant changes to the operating, investing and financing cash flows other then the adjustments related to the expensing of dry holes, seismic costs and lease rentals to operating and the reclassification of financing expenses from funds used in operating activities to funds used in financing activities.

Future Accounting Changes

The following are pronouncements from IASB that may have an effect on Arsenal's financial position. They will become effective for financial reporting periods beginning on or after January 1, 2013. They have not been adopted by the Company as yet and an evaluation of the effect on the Company's financial position has not been determined.

IFRS 9 – Financial Instruments Measurement – addresses the classification and measurement of financial assets.

IFRS 13 – Fair Value Measurement – defines fair value, requires disclosure about fair value measurements and provides a framework for measuring fair value when it is required or permitted within IFRS standards.

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 months ended June 30, 2011 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, 2011 to material weaknesses in internal controls over financial reporting.