MANAGEMENT DISCUSSION AND ANALYSIS

SUMMARY OF FINANCIAL AND OPERATIONAL RESULTS						
	Three Months Ended December 31			Year Ended December 31		
(000'S Cdn. $ except per share amounts)	**2012**	2011	% Change	**2012**	2011	% Change
FINANCIAL						
Oil and gas revenue	**22,351**	19,089	**17**	**82,168**	58,466	**41**
Funds from operations	**10,000**	8,441	**18**	**31,119**	29,274	**6**
Per share - basic and diluted	**0.06**	0.05	**20**	**0.20**	0.18	**8**
Net loss	**(896)**	(4,051)	**(78)**	**(112)**	(2,545)	**(96)**
Per share - basic and diluted	**(0.01)**	(0.03)	**(78)**	**0.00**	(0.02)	**(100)**
Total debt	**68,492**	55,752	**23**	**68,492**	55,752	**23**
Capital expenditures	**10,749**	13,578	**(21)**	**42,681**	40,471	**5**
Property acquisition	**-**	38,575	**(100)**	**-**	38,575	**(100)**
Proceeds on property dispositions	**-**	-	**-**	**(1,928)**	(622)	**210**
Shares outstanding - end of period	**155,948**	157,282	**(1)**	**155,948**	157,282	**(1)**
OPERATIONAL						
Wells drilled (net)						
Oil	**1.16**	1.40	**(17)**	**6.14**	6.02	**2**
Gas	**-**	-	**-**	**-**	-	**-**
Dry	**-**	-	**-**	**-**	3.00	**(100)**
Total net wells drilled	**1.16**	1.40	**(17)**	**6.14**	9.02	**(32)**
Daily production						
Heavy oil (bbl/d)	**72**	124	**(42)**	**112**	170	**(34)**
Light oil and NGLs (bbl/d)	**2,949**	2,082	**42**	**2,661**	1,654	**61**
Natural gas (mcf/d)	**5,483**	4,158	**32**	**5,697**	2,439	**134**
Oil equivalent (boe @ 6:1)	**3,934**	2,899	**36**	**3,723**	2,230	**67**
Realized commodity prices ($Cdn.)						
Heavy oil (bbl)	**71.63**	81.85	**(12)**	**70.70**	70.84	**-**
Light oil and NGLs (bbl)	**75.31**	88.93	**(15)**	**76.50**	84.47	**(9)**
Natural gas (mcf)	**2.88**	2.93	**(2)**	**2.28**	3.47	**(34)**
Oil equivalent (boe @ 6:1)	**61.76**	71.57	**(14)**	**60.31**	71.82	**(16)**
Operating netback ($ per boe)						
Revenue	**61.76**	71.57	**(14)**	**60.31**	71.82	**(16)**
Royalty	**(12.26)**	(15.58)	**(21)**	**(12.52)**	(14.47)	**(13)**
Operating cost	**(19.05)**	(19.19)	**(1)**	**(20.28)**	(19.44)	**4**
Operating netback per boe	**30.44**	36.80	**(17)**	**27.50**	37.91	**(27)**
General and administrative	**(2.77)**	(2.80)	**(1)**	**(3.03)**	(4.88)	**(38)**
Finance expenses	**(1.63)**	(1.43)	**14**	**(1.67)**	(1.15)	**46**
Realized gains (losses) on risk management contracts	**1.75**	(1.30)	**235**	**0.07**	4.12	**(98)**
Other	**(0.16)**	0.38	**(143)**	**(0.02)**	(0.05)	**(49)**
Funds flow per Boe	**27.63**	31.65	**(13)**	**22.84**	35.96	**(36)**

2012 Financial and Operational Highlights

Arsenal's production for Q4 2012 averaged 3,934 Boe per day (77% crude oil and NGL's and 23% natural gas) versus a Q3 2012 average of 3,694 Boe per day (76% crude oil and NGL's and 24% natural gas) and a Q4 2011 average of 2,899 Boe per day (76% crude oil and NGL's and 24% natural gas). Production has increased from Q4 2011 due to a mid Q4 2011 property acquisition of approximately 1,500 Boe per day of production in the Provost and Princess areas of Alberta and the Desan area of British Columbia (the "Q4 2011 Property Acquisition"), and from Q3 2012 and Q4 2011 due to production added from the drilling and completion of North Dakota Bakken oil wells and from successful well and work over programs at Princess and Provost in Alberta. The production mix has been relatively consistent over the various compared periods.

For Q4 2012, the Company's operating netback per Boe (revenues less royalties and operating expenses) increased 12% to $30.44 per Boe from $27.17 per Boe in Q3 2012 and decreased 17% from $36.80 per Boe realized in Q4 2011. For the year ended December 31, 2012, the Company's operating netback per Boe decreased 27% to $27.50 per Boe from $37.91 per Boe for the year ended December 31 2011. Lower realized crude prices due to lower realized average prices from higher differentials during the current year offset by increased production and account for most of the decrease.

Funds from operations for Q4 2012 totaled $10.0 million or $0.06 per share basic and diluted versus $7.8 million or $0.05 per share basic and diluted in Q3 2012 and $8.4 million or $0.05 per share basic and diluted in Q4 2011. For the year ended December 31, 2012, funds flow from operations totaled $31.1 million or $0.20 per share basic and diluted compared to $29.3 million or $0.18 per share basic and diluted in 2011. Funds flow from operations for 2012 increased by $6.6 million when compared to 2011 due to higher average production offsetting lower average prices. 2011 included a $3.4 million realized hedging gain versus $93,178 in 2012.

Arsenal's cash netback per Boe (funds flow from operations per Boe) in Q4 2012 increased by 21% to $27.63 per Boe from $22.90 per Boe in Q3 2012 and decreased by 13% from $31.65 per Boe in Q4 2011. Operating margins were reduced by $6.36 per Boe in Q4 2012 versus Q4 2011 due to lower prices. Monetized commodity contracts added $1.75 per Boe to the cash netback in Q4 2012 versus a recorded realized loss of $1.30 per Boe in Q4 2011. For the year ended December 31, 2012, the Company's cash netback per Boe decreased 36% to $22.84 per Boe from $35.96 per Boe in 2011. Operating margins were reduced in 2012 by $10.41 per Boe versus 2011 due to lower commodity prices. Monetized commodity contracts added $4.12 per Boe to the cash netback in 2011 versus adding $0.07 per Boe to the cash netback in 2012.

In January 2013, based on year end information and the 2013 budget, the Company's syndicate of lenders reviewed and increased the Company's credit facility to $85 million. The next review date is May 31, 2013. The Company's total debt (see Credit Facility) at December 31, 2012 was $62.5 million, up from $52.1 million at December 31, 2011. The Company's debt increased in 2012 primarily due to investing activities and exploration and evaluation expenditures exceeding funds from operations during the year by $12.5 million.

Investing activities to December 31, 2012 totaled $42.7 million versus $79.0 million in 2011. In 2011 the Company spent $38.6 million on the Q4 2011 Property Acquisition. Capital expenditures in Canada ($13.1 million) were incurred to purchase land at Columbia, Princess and Galahad, to drill and complete a well at Princess, on recompletions at Evi, Princess and Galahad and on water injection facilities at Princess. Capital expenditures in the US ($29.6 million) were incurred to drill and complete North Dakota Bakken and Three Forks wells at Stanley and Lindahl and to lease additional lands at Rennie Lake/Black Slough.

On June 19, 2012, a normal course issuer bid ("NCIB") that commenced June 20, 2011 expired. A total of 6,600,044 common shares, at an average cost of $0.65 per share, were acquired under the bid. Of these, a total of 1,141,500 common shares were acquired in 2012 at an average cost of $0.67 per share.

On July 5, 2012, the Company announced its intention to make a ("NCIB") normal course issuer bid that commenced July 9, 2012 and ends on July 8, 2013. A total of 7,809,705 common shares may be acquired under the bid, representing 5% of the 156,194,094 common shares outstanding as of July 4, 2012. During 2012, as part of this new NCIB, the Company acquired 506,500 common shares at an average price of $0.54 per share plus expenses.

Arsenal has 157,136,760 common shares and 14,714,003 stock options outstanding as of March 18, 2013. 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 for 2012 averaged 2,455 Boe per day and funds from operations totaled $12.9 million in 2012. In the US, the Company operates under its 100% owned subsidiary Arsenal Energy USA Inc. Production in the US for 2012 averaged 1,268 Boe per day and funds from operations totaled $18.2 million for 2012.

Basis of Presentation

The following is management's discussion and analysis ("MD&A") of Arsenal Energy Inc.'s ("Arsenal" or the "Company") audited operating and financial results for the year ended December 31, 2012. It should be read in conjunction with the audited consolidated financial statements and related notes of the Company for the year ended December 31, 2012 and other operating and financial information contained herein and in conjunction with the Annual Information Form ("AIF") for the year ended December 31, 2012 which includes reserves information prepared in accordance with National Instrument 51 – 101 – Standards of Disclosure for Oil and Gas Activities. This MD&A is dated March 18, 2013.

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.

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 MD&A 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 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; 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 laws and regulations.

We believe the expectations reflected in these 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 other legislation applicable to our operations, and our ability to comply with current and future environmental and other laws; and changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry. 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 herein are expressly qualified by this cautionary statement and speak only as of the date of this MD&A 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 oil equivalent (Boe).

Non-GAAP Measurements

Within this 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", "Cash Netback per unit or per Boe", "Net Debt", "Total Debt" or "Bank Debt" are not defined by International Financial Reporting Standards ("IFRS") in Canada and are regarded as non-GAAP measures.

Operating (or field) netbacks equal total revenue less royalties and operating costs (that include transportation expenses) calculated on a commodity and Boe basis. Boe production per day is calculated by dividing total production for the quarter or period, as the case may be, by the number of days in the quarter or period. Funds flow from operations netback is operating netback plus or minus realized gains or losses on risk management (commodity and interest) 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 calculated as net cash from operating activities before transaction costs, seismic expenses, decommissioning obligations settled and the change in non-cash operating working capital. 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 share diluted are calculated based on the weighted average number of common shares outstanding adjusted for dilutive instruments, which in Arsenal's case consist only of stock options, consistent with the calculation of diluted earnings per share.

The following tables compare net cash from operating activities to funds from operations, funds from operations by country and funds from operations netback per Boe for Q4 2012 to Q4 2011 and for the year ended December 31, 2012 to the year ended December 31, 2011.

Funds From Operations	**Three Months Ended December 31**			**Year Ended December 31**		
(000's Cdn. $)	**2012**	**2011**	% Change	**2012**	2011	% Change
Net cash from operating activities	**4,918**	2,258	118	**29,700**	24,687	20
Seismic expenses (sales)	**988**	793	25	**898**	1,555	(42)
Transaction costs	**1,019**	614	66	**1,132**	614	84
Decommissioning obligations settled	**267**	311	(14)	**477**	819	(42)
Change in non-cash working capital	**2,807**	4,464	37	**(1,088)**	1,598	168
Funds from operations	**10,000**	8,441	18	**31,119**	29,273	6

Funds From Operations By Country	**Three Months Ended December 31**			**Year Ended December 31**		
(000's Cdn. $)	**2012**	2011	% Change	**2012**	2011	% Change
Canada	**4,795**	3,955	21	**12,910**	16,252	(21)
US	**5,205**	4,485	16	**18,210**	13,022	40
Funds from operations	**10,000**	8,441	18	**31,119**	29,274	6

Funds From Operations Per Boe	**Three Months Ended December 31**			**Year Ended December 31**		
($Cdn.)	**2012**	2011	% Change	**2012**	2011	% Change
Canada	**21.26**	23.59	(10)	**14.37**	31.60	(55)
US	**38.19**	45.28	(16)	**39.26**	43.45	(10)
Total	**27.63**	31.65	(13)	**22.84**	35.96	(36)

For Q4 2012, funds from operations totaled $10.0 million or $27.63 per Boe versus $8.4 million or $31.65 per Boe in Q4 2011. The operating netback in Q4 2012 was $30.44 per Boe versus $36.80 per Boe in Q4 2011. The average price received decreased by $9.81 per Boe in Q4 2012 versus Q4 2011. As a result, royalties decreased by $3.32 per Boe. Operating and transportation expenses remained relatively constant averaging $19.05 per Boe in Q4 2012 versus $19.19 per Boe in Q4 2011. Funds from operations netback for Q4 2012 included a monetized gain on commodity contracts of $633,293 or $1.75 per Boe versus a monetized loss in Q4 2011 of $346,955 or $1.30 per Boe.

For 2012, funds from operations totaled $31.1 million or $22.84 per Boe versus $29.3 million or $35.96 per Boe in 2011. The operating netback in 2012 was $27.50 per Boe versus $37.91 per Boe in 2011. The average price received decreased in 2012 by $11.51 per Boe. As a result, royalties decreased by $1.95 per Boe. Operating and transportation expenses increased by $0.84 per Boe over 2011 expenses to average $20.28 per Boe in 2012. Funds from operations netback for 2012 included a monetized gain on commodity contracts of $93,178 or $0.07 per Boe versus a monetized gain in 2011 of $3.4 million or $4.12 per Boe.

The following tables show quarterly production and compares funds flow from operations by country and funds flow from operations per Boe both before and after the effect of commodity contracts for the past eight quarters.

Production	**2012**				2011			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Oil and NGL's (bbls)	**3,020**	2,808	2,583	2,681	2,206	1,926	1,508	1,648
Natural gas (mcf)	**5,483**	5,319	5,837	6,155	4,158	1,552	1,908	2,126
Total Boe	**361,886**	339,816	323,485	337,339	266,719	201,002	166,149	180,167
Boe per day	**3,934**	3,694	3,555	3,707	2,899	2,185	1,826	2,002

Production By Country	**2012**				2011			
(Boe per day)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Canada	**2,452**	2,274	2,443	2,655	1,822	1,235	1,245	1,331
US	**1,482**	1,420	1,112	1,052	1,077	950	581	671
Total	**3,934**	3,694	3,555	3,707	2,899	2,185	1,826	2,002

Funds From Operations By Country	**2012**				2011			
(000's Cdn. $)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Canada	**4,795**	2,431	2,630	3,053	3,955	6,285	2,684	3,327
US	**5,205**	5,351	3,908	3,746	4,485	5,141	1,618	1,778
Total	**10,000**	7,782	6,538	6,799	8,441	11,426	4,302	5,106

Funds From Operations	**2012**				2011			
(000's Cdn. $)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Before risk management contracts	**9,366**	7,544	6,535	7,581	8,787	6,951	4,802	5,377
Realized risk mamagement contracts	**633**	238	3	(782)	(347)	4,475	(500)	(271)
After commodity contracts	**10,000**	7,782	6,538	6,799	8,441	11,426	4,302	5,106

Funds From Operations Per Boe	**2012**				2011			
(000's Cdn. $)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Before risk management contracts	**25.88**	22.20	20.20	22.47	32.95	34.58	28.90	29.84
After risk management contracts	**27.63**	22.90	20.21	20.16	31.65	56.84	25.89	28.34

The increases and decreases in the above periods relate primarily to increases in production, fluctuations in commodity prices, changes to operating costs as a result of timing of workovers and operating initiatives and the acquisition and disposition of properties, changes in interest and financing charges as a result of increases in or decreases to average bank borrowings from the timing of capital expenditures or equity issues, and realized hedging gains or losses from commodity contracts. In addition, production from new high rate, high netback North Dakota Bakken wells impacts production and funds from operations before commodity contracts.

Net Asset Value

		As at December 31						**2012/2011**
(000's Cdn. $)	**2012**	2011	2010	2009	2008	2007	2006	**% Change**
Present value of proved plus probable reserves, before tax at 10% [1]	**245,940**	296,349	201,441	200,832	166,384	87,600	77,100	**(17)**
Undeveloped land and seismic [2]	**18,000**	12,000	8,400	3,000	2,900	2,300	1,800	**50**
Cash proceeds on exercise of stock options [3]	**4,478**	4,243	7,349	2,790	-	166	343	**6**
Total debt [4]	**(68,492)**	(55,752)	(18,788)	(28,739)	(48,479)	(20,700)	(28,500)	**23**
Net asset value before tax	**199,926**	256,840	198,403	177,883	120,805	69,366	50,743	**(22)**
Fully diluted common shares outstanding (000s)	**157,575**	165,888	153,027	127,454	101,250	84,207	74,389	**(5)**
Net asset value per common share ($/share)	**1.27**	1.55	1.30	1.40	1.19	0.82	0.68	**(18)**

[1] Based on report of AJM Deloitte effective December 31, 2012, 2011, 2010, 2009, 2008, 2007 and 2006

[2] Based on management's estimate of fair value at December 31, 2012, 2011, 2010, 2009, 2008, 2007 and 2006

[3] Based on closing price of Arsenal shares at December 31, 2012, 2011, 2010, 2009, 2008 , 2007 and 2006 of $0.53, $0.69, $1.08, $0.70, $0.21, $0.41 and $.078 respectively

[4] Total debt includes bank borrowings, debentures outstanding, if applicable, and working capital whether excess or deficiency, but excludes the value of risk management contracts

The Company's net asset value per share decreased 18% in 2012 due primarily to technical revisions to probable reserves in the US (the well sample used to generate probabilistic distribution changed from harmonic to exponential decline) and to lower prices.

OUTLOOK AND 2013 GUIDANCE

In Canada, Arsenal has commenced an oil development project in the Glauconite formation at Princess and has exploration projects in the Cardium and Wilrich formations at Columbia targeting a liquids rich natural gas and in the Leduc formation at Edgerton targeting oil. Additional waterflood development opportunities exist at both Princess and Provost. At Princess, Arsenal shot 3D seismic, reprocessed existing seismic, acquired additional lands and in Q1 2013 drilled two follow-up horizontal Glauconite wells. These wells are currently being production tested. An additional 5 net wells have been identified and are expected to be drilled by year end 2013. In addition, Arsenal drilled one net well in the Basal Mannville formation at Princess that is waiting on tie in and production testing. With oil from this project area currently subject to unusually high differentials, the drilling of up to 6 additional wells has been deferred until later this year when differentials are expected to have narrowed.

At Columbia in the Deep Basin, Arsenal has a land block prospective for the Cardium and Wilrich. Competitors in the area continue to reduce Arsenal's exploration and economic risk through successful drilling offsetting our lands. Recent horizontal Cardium wells in the area and land sales in the area have been very encouraging. Wells have tested at 4 mmcf/d of gas with 50 barrels per mmcf of associated liquids. Over time these wells will establish the long term potential of the Cardium. In addition, other competitors have licenced numerous and drilled some wells in the area testing the Wilrich and Gething formations. Some of the reporteds results have been quite prolific. The Company plans to evaluate these lands with a well in 2013.

In the US, Arsenal is continuing to develop its Bakken reserves at Stanley with the drilling of up to 4 gross, 1.6 net wells planned for 2013.

At Lindahl, Arsenal participated in the drilling of 4 wells drilled from eco pads in which Arsenal has a working interest of approximately 6.3%. These wells were completed and put on stream in Q1 2013. Arsenal expects the operator in the area to drill four additional eco pad wells in 2013.

At Rennie Lake/Black Slough, as a result of Arsenal adding to its acreage position in the area and competitor drilling offsetting our lands continuing to occur, the risk on our lands is reduced. Arsenal has received a partner operated AFE to participate at a 12.5% working interest in a well licensed to evaluate exploratory lands at Rennie Lake. This well is expected to be drilled in Q2 2013.

Outlook

Funds from operations of $31.1 million for 2012 were negatively impacted by lower commodity prices and increased crude differentials in both Canada and the US. The differentials started increasing in mid Q1 2012, continued into Q3 2012 but by late Q1 2013 have indicated a possible return to more normal levels although additional fluctuations are to be expected. Arsenal's successful drilling at Princess in Alberta supports additional development with drilling to commence as soon as differentials improve. In the US, while differentials have fluctuated somewhat, current differentials from WTI are acceptable to support further Bakken drilling. Accordingly, Arsenal has decided to drill two high working interest wells in North Dakota. The first well is currently drilling with the second well to spud upon completion of drilling of the first. Both will be completed and are expected to be on stream in late Q2 2013. Arsenal is proceeding both prudently and cautiously with its remaining 2012 capital projects and with the planning and budgeting of the remaining of its 2013 capital program.

At Lindahl, the Company participated in the drilling of 4 gross 0.25 net pad drilled wells in 2012 that commenced production in Q1 2013. The pad drilling of four additional wells is budgeted for Q3 2013. These wells should be on production by year end 2013.

In the Black Slough/Rennie Lake area of North Dakota, Arsenal has received an AFE to drill a well (12.5% net) to test exploration lands in this prospect area. Competitors have drilled some encouraging Bakken wells surrounding the Company's acreage. This well is expected to be drilled in 2013.

Guidance

Due to the somewhat unexpected increase in the differentials in the US but more particularly in Canada, the Company has rescheduled the timing of projects in Canada and accelerated drilling in the North Dakota Bakken. This has resulted in changes to the Company's original 2013 guidance. Based on the expectation that the current high different will return to more normal levels during the middle part of 2013 and on the current expected timing of drilling and completions of wells in the US and in Canada, Arsenal expects 2013 funds from operations to total approximately $40.0 million down from $44 million projected earlier. This is based on total capital expenditures for the year of approximately $42 million down from $49 million previously forecast. Debt at year end is now expected to total approximately $72 million up somewhat from $69 million originally forecast. Average production is estimated at approximately 4,000 Boe per day slightly lower than 4,200 Boe per day originally expected. 2013 exit production is estimated at approximately 4,100 Boe per day.

PRODUCTION AND REVENUE

Average Daily Production

Production for Q4 2012 averaged 3,934 Boe per day versus 3,694 Boe per day in Q3 2012 and 2,899 Boe per day in Q4 2011. Average daily production increased from Q4 2011 to Q4 2012 primarily due to a mid Q4 2011 property acquisition adding approximately 1,500 Boe per day in the Provost and Princess areas of Alberta and the Desan area of British Columbia (the "Q4 2011 Property Acquisition"). For the year 2012, production averaged 3,723 Boe per day versus 2,230 Boe per day in 2011. Year over year and quarterly production increases are also the result of incremental production from the drilling and completion of North Dakota Bakken oil wells, from favorable drilling results at Princess, Alberta and from successful reactivation and recompletion activities at Princess and Provost in Alberta.

Production in 2013 should increase over the year with additional Bakken drilling in North Dakota, the drilling program to follow up the successful Glauconite wells drilled at Princess, Alberta in 2012 and from ongoing reactivations and recompletions.

The Company produces in the provinces of Alberta, British Columbia and Saskatchewan in Canada (62% of total Q4 2012 production and 66% of 2012 production) and in the state of North Dakota in the US (38% of total Q4 2012 production and 34% of 2012 production). The percentage of production from the US increased 4% to 1,482 Boe per day in Q4 2012 from Q3 2012 due to drilling activities in Q3 and Q4 2012. Production from the Bakken formation is characterized by high initial production followed by declines within a few months, after which, production declines become more shallow. In addition, the production is characterized by low operating costs and high operating netbacks.

Production Profile

Average Daily Production	Three Months Ended December 31			Year Ended December 31		
	2012	2011	% Change	**2012**	2011	% Change
Canada						
Heavy oil (bbls)	**72**	124	- 42	**112**	170	- 34
Light oil and NGL's (bbls)	**1,544**	1,072	44	**1,461**	895	63
Natural gas (mcf)	**5,018**	3,758	34	**5,293**	2,068	156
Total Boe	**2,452**	1,822	35	**2,455**	1,409	74
US						
Heavy oil (bbls)	**-**	-	-	**-**	-	-
Light oil and NGL's (bbls)	**1,405**	1,010	39	**1,201**	759	58
Natural gas (mcf)	**464**	400	16	**404**	372	9
Total Boe	**1,482**	1,077	38	**1,268**	821	54
Total						
Heavy oil (bbls)	**72**	124	- 42	**112**	170	- 34
Light oil and NGL's (bbls)	**2,949**	2,082	42	**2,661**	1,654	61
Natural gas (mcf)	**5,483**	4,158	32	**5,697**	2,439	134
Total Boe	**3,934**	2,899	36	**3,723**	2,230	67

Production in Q4 2012 and for the year ended 2012 increased over Q4 2011 and the year ended 2011 due primarily to North Dakota Bakken drilling and the Q4 2011 Property Acquisition. The production increase from 3,694 Boe per day in Q3 2012 to 3,934 Boe per day in Q4 2012 was also due to full quarter production from North Dakota Bakken oil wells completed in Q3 2012 and additional well coming on stream in Q4 2012.

Production Profile

By Commodity	Three Months Ended December 31			Year Ended December 31		
	2012	2011	% Change	**2012**	2011	% Change
Heavy oil	**2%**	4%	(57)	**3%**	8%	(60)
Light oil and NGLs	**75%**	72%	4	**71%**	74%	(4)
Natural gas	**23%**	24%	(3)	**26%**	18%	40

In 2012, natural gas represents a higher proportion of production than in 2011 due to the Q4 2011 Property Acquisition that added approximately 750 Boe per day of natural gas production. Arsenal did not drill any natural gas wells in 2012.

By Country	Three Months Ended December 31			Year Ended December 31		
	2012	2011	% Change	**2012**	2011	% Change
Canada	**62%**	63%	(1)	**66%**	63%	4
US	**38%**	37%	1	**34%**	37%	(8)

Production in Canada in 2012 increased as a percentage of total production due to the Q4 2011 Property Acquisition that added combined oil and natural gas production of approximately 1,500 Boe per day. Production in the US fluctuates and is influenced by the timing of bringing high rate, high working interest wells on production. In 2013, additional production is expected from wells currently being drilled in North Dakota in the Bakken formation and from wells to be drilled in the Princess and Edgerton areas of Alberta.

Production by Area

	Three Months Ended December 31				Year Ended December 31			
	2012		2011		**2012**		2011	
AREA	**Boe/d**	**% of Total**	Boe/d	% of Total	**Boe/d**	**% of Total**	Boe/d	% of Total
Canada								
Galahad (light oil)	**142**	**4**	185	6	**165**	**4**	237	11
Princess (medium oil and gas)	**593**	**15**	216	7	**441**	**12**	98	4
Chauvin (medium oil and gas)	**329**	**8**	301	10	**321**	**9**	312	14
Provost (medium oil and gas)	**493**	**12**	348	12	**494**	**13**	101	5
Consort (medium oil and gas)	**78**	**2**	-	-	**91**	**3**	-	-
Evi (light oil)	**163**	**4**	206	7	**191**	**5**	244	11
Desan (gas)	**503**	**13**	339	12	**575**	**16**	85	4
Tomahawk	**25**	**1**	-	-	**11**	**-**	-	-
Others	**126**	**3**	227	8	**166**	**4**	332	15
Total Canada	**2,452**	**62**	1,822	63	**2,455**	**66**	1,409	63
US								
Stanley (light oil)	**1,281**	**34**	822	28	**1,077**	**29**	550	25
Lindahl (light oil)	**122**	**3**	160	6	**118**	**3**	173	8
Rennie Lake/Black Slough (light oil)	**43**	**1**	42	1	**34**	**1**	43	2
Lake Darling (light oil)	**21**	**-**	-	-	**21**	**1**	-	-
Other	**15**	**-**	53	2	**18**	**-**	55	2
Total US	**1,482**	**38**	1,077	37	**1,268**	**34**	821	37
Total	**3,934**	**100**	2,899	100	**3,723**	**100**	2,230	100

The decrease in the Galahad area production resulted from depletion of a solution gas cap that started to produce in early 2011. This gas cap has been replaced by lower rate crude production. Production increased in Princess, Provost, Consort and Desan due to Q4 2012 Glauconite drilling and to the Q4 2011 Property Acquisition. Evi production has fallen due to natural production declines, Desan gas production decreased due to operational issues, causing a shut in during part of Q4 2012 and Tomahawk production has been shut in periodically due to negative operating netbacks.

Production has been added at Princess from Glauconite drilling and at Stanley from Bakken drilling where high initial rate production typically declines quickly and stabilizes within 6 – 9 months. Production will increase in 2013 at Princess with additional drilling and at Stanley and Lindahl with additional wells having been completed in Q4 2012 and Q1 2013 and from wells being drilled in 2013. Arsenal's other US properties, Lindahl, Rennie Lake and Lake Darling, have experienced normal production declines.

Prices

Reference Prices	Three Months Ended December 31			Year Ended December 31		
	2012	2011	% Change	**2012**	2011	% Change
WTI Cushing, Oklahoma ($U.S./bbl)	**88.30**	94.17	(6)	**94.16**	95.00	(1)
Light Oil Edmonton Par 40 API ($Cdn./bl	**84.28**	97.87	(14)	**86.53**	95.16	(9)
Hardisty Bow River 24.9 API ($Cdn./bbl	**70.38**	87.16	(19)	**74.30**	78.30	(5)
Hardisty Heavy 12 API ($Cdn./bbl	**61.13**	77.83	(21)	**64.99**	69.10	(6)
AECO (daily spot) ($Cdn./MMBtu)	**3.22**	3.37	(4)	**2.39**	3.62	(34)
Henry Hub NYMEX Close ($U.S./MMBu)	**3.40**	3.55	(4)	**2.79**	4.04	(31)
Foreign exchange ($Cdn./$U.S.)	**1.01**	0.98	3	**1.00**	1.01	(1)

Prices - Before Commodity Contracts	Three Months Ended December 31			Year Ended December 31		
($Cdn.)	**2012**	2011	% Change	**2012**	2011	% Change
Canada						
Heavy oil per barrel	**71.63**	81.85	(12)	**70.70**	70.84	-
Light oil and NGL's per barrel	**70.13**	90.61	(23)	**74.36**	83.54	(11)
Natural gas per mcf	**2.83**	2.76	2	**2.22**	3.24	(32)
Total per Boe	**52.04**	64.56	(19)	**52.26**	66.33	(21)
US						
Heavy oil per barrel	**-**	-	-	**-**	-	-
Light oil and NGL's per barrel	**81.01**	87.15	(7)	**79.09**	85.55	(8)
Natural gas per mcf	**3.43**	4.52	(24)	**3.13**	4.72	(34)
Total per Boe	**77.85**	83.43	(7)	**75.89**	81.24	(7)
Total						
Heavy oil per barrel	**71.63**	81.85	(12)	**70.70**	70.84	-
Light oil and NGL's per barrel	**75.31**	88.93	(15)	**76.50**	84.47	(9)
Natural gas per mcf	**2.88**	2.93	(2)	**2.28**	3.47	(34)
Total per Boe	**61.76**	71.57	(14)	**60.31**	71.82	(16)

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 generally reflective of the movement in commodity prices and differentials over the comparative periods.

In Canada, the price the Company received for its heavy oil in Q4 2012 and for 2012 was indicative of the decrease in Hardisty heavy oil prices during these periods of 14% and 5% respectively. The price received for light oil and NGL's in Canada was 23% lower in Q4 2012 versus Q4 2011 and decreased 11% in 2012 versus 2011. The reference price for the Hardisty Bow River stream (24.9 API), which represents an approximate reference price of the average price the Company receives for its mix of light oil, decreased 19% and 5% during these comparable periods. The differentials during 2012 fluctuated quite significantly, especially in Q4 2012. The Canadian price received for natural gas generally tracks changes to the AECO price which was down from Q4 2011 by 4% and down in 2012 versus 2011 by 31%.

In the US, where much of the Company's production is from the Bakken which is 41 degree sweet oil, the Q4 2012 decrease in WTI (6% over Q4 2011) and the differentials in North Dakota, resulted in an average Q4 2012 price received that was 7% less than the Q4 2011 average price. The differentials in Q4 2012 were the lowest of any quarter during 2012. For 2012, the oil price received in the US decreased 8% versus 2011 due primarily to increased differentials over the period as the price of WTI remained relatively flat. The price received for natural gas in the US decreased 34% over 2012 versus 2011 consistent with the 31% decrease in the price decrease over the year at Henry Hub.

The Company received a corporate average price per Boe during Q4 2012 of $61.76 per Boe, a decrease of 14% from $71.57 per Boe received in Q4 2011. This decrease is primarily attributed to lower reference commodity prices and increased crude differentials. For 2012, the corporate average price received of $60.31 per Boe was down from $71.82 per Boe received in 2011 and was reflective of the general decrease in commodity prices year over year.

Oil and Natural Gas Revenue

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2012**	2011	% Change	**2012**	2011	% Change
Canada						
Heavy oil	**472**	931	(49)	**2,910**	4,390	(34)
Light oil and NGL's	**9,962**	8,939	11	**39,756**	27,281	46
Natural gas	**1,306**	954	37	**4,298**	2,445	76
Total	**11,740**	10,824	8	**46,963**	34,116	38
US						
Heavy oil	**-**	-	-	**-**	-	-
Light oil and NGL's	**10,464**	8,099	29	**34,743**	23,709	47
Natural gas	**146**	166	(12)	**462**	641	(28)
Total	**10,611**	8,265	28	**35,205**	24,350	45
Total						
Heavy oil	**472**	931	(49)	**2,910**	4,390	(34)
Light oil and NGL's	**20,427**	17,038	20	**74,499**	50,990	46
Natural gas	**1,452**	1,121	30	**4,760**	3,086	54
Oil and natural gas revenues	**22,351**	19,089	17	**82,168**	58,466	41
Gain (loss) on realized commodity contracts	**633**	(347)	(283)	**93**	3,357	(97)
Oil and gas revenue after realized commodity contracts	**22,984**	18,742	23	**82,262**	61,823	33
Per boe before realized commodity contracts	**61.76**	71.57	(14)	**60.31**	71.82	(16)
Per boe after realized commodity contracts	**63.51**	70.27	(10)	**60.37**	75.95	(21)

Total oil and natural gas revenues increased 17% or $3.3 million in Q4 2012 over Q4 2011. A 36% increase in production in Q4 2012 versus Q4 2011 offset a decline in the average commodity price per Boe of 14% or $9.81 per Boe.

For 2012, total oil and gas revenues increased 41% or $23.7 million over 2011. A 67% increase in production in 2012 over 2011 offset a decline in the average commodity price per Boe of 16% or $11.51 per Boe.

Royalties

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2012**	2011	% Change	**2012**	2011	% Change
Canada						
Heavy oil	**29**	181	(84)	**407**	770	(47)
Light oil and NGL's	**1,326**	1,526	(13)	**7,054**	4,265	65
Natural gas	**(5)**	78	(107)	**135**	119	14
Total	**1,350**	1,786	(24)	**7,596**	5,153	47
US						
Heavy oil	**-**	-	-	**-**	-	-
Light oil and NGL's	**3,059**	2,341	31	**9,382**	6,509	44
Natural gas	**29**	29	1	**87**	115	(25)
Total	**3,088**	2,370	30	**9,468**	6,624	43
Total						
Heavy oil	**29**	181	(84)	**407**	770	(47)
Light oil and NGL's	**4,386**	3,867	13	**16,436**	10,774	53
Natural gas	**24**	107	(78)	**221**	234	(5)
Royalties	**4,438**	4,156	7	**17,064**	**11,777**	45

Percentage By Product	Three Months Ended December 31			Year Ended December 31		
	2012	2011	% Change	**2012**	2011	% Change
Heavy oil	**6**	19	(68)	**14**	18	(20)
Light oil and NGL's	**21**	23	(5)	**22**	21	4
Natural gas	**2**	10	(83)	**5**	8	(39)
Total	**20**	22	(9)	**21**	20	3

Percentage By Country	Three Months Ended December 31			Year Ended December 31		
	2012	2011	% Change	**2012**	2011	% Change
Canada	**11**	16	(30)	16	15	7
US	**29**	29	2	27	27	(1)
Total	**20**	22	(9)	21	20	3

The Company's royalty rate for Q4 2012 averaged 20% versus a rate of 19% in Q3 2012 and 22% in Q4 2011. For 2012, the royalty rate averaged 21% versus 20% in 2011. The royalty rate changes during the respective periods relate to commodity prices and to the royalty rates on new production in both Canada and in the US. In Canada, royalty rates fluctuate due largely to the low royalty rate incentives on new wells (Princess) and in the US, royalty rates fluctuate based on the terms of freehold leases. US royalty rates are generally higher (particularly on new leases) than rates in Canada. The royalty rate in the US includes a 6.5% North Dakota production tax.

Royalty rates looking forward are expected to average in the 20% - 25% range. The rate fluctuates due to adjustments to the Company's gas cost allowance and to some degree on 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 Company's average royalty rate as US royalty rates paid by the Company are higher than those in Canada.

Per Boe	Three Months Ended December 31			Year Ended December 31		
($Cdn.)	**2012**	2011	% Change	**2012**	2011	% Change
Canada						
Heavy oil per barrel	**4.44**	15.93	(72)	**9.90**	12.42	(20)
Light oil and NGL's per barrel	**9.33**	15.47	(40)	**13.19**	13.06	1
Natural gas per mcf	**(0.01)**	0.23	(105)	**0.07**	0.16	(56)
Total per Boe	**5.98**	10.65	(44)	**8.45**	10.02	(16)
US						
Heavy oil per barrel	**-**	-	-	**-**	-	-
Light oil and NGL's per barrel	**23.68**	25.20	(6)	**21.36**	23.49	(9)
Natural gas per mcf	**0.68**	0.78	(13)	**0.59**	0.85	(31)
Total per Boe	**22.66**	23.93	(5)	**20.41**	22.10	(8)
Total						
Heavy oil per barrel	**4.44**	15.93	(72)	**9.90**	12.42	(20)
Light oil and NGL's per barrel	**16.17**	20.19	(20)	**16.88**	17.85	(5)
Natural gas per mcf	**0.05**	0.28	(83)	**0.11**	0.26	(60)
Royalties per Boe	**12.26**	15.58	(21)	**12.52**	14.47	(13)

On a Boe basis, the Q4 2012 royalty was $12.26 per Boe versus $11.00 per Boe for Q3 2012 and $15.58 per Boe for Q4 2011. Commodity prices and the percentage of production from the higher royalty rate production in the US are major factors in these fluctuations. In 2012, the Company paid $12.52 per Boe in royalties versus $14.47 in 2011. These rates are in line with the decline in commodity prices over the respective periods and the royalty rates on new production from drilling in the US. Changes in the Boe royalty rate are expected and will fluctuate as a

result of changes in commodity prices, the higher percentage of revenue from the US and the timing of royalty holiday periods in Canada.

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 earnings.

In Q4 2011, in order to lock in the metrics of a portion of the production from the Q4 2011 Property Acquisition, the Company entered into commodity contracts covering parts of 2011, 2012 and 2013. In 2012, the Company added to its hedged position for 2013 and 2014. In 2012, because of the timing of the initiation of these contracts and the fluctuation in the price of WTI in Canadian dollars for the future settlement of these contracts, these contracts have resulted in a combination of realized and unrealized gains. In Q4 2012, based on the average settlement prices in the quarter, these contracts resulted in realized gains of $633,293. For 2012, based on the average settlement prices during the year, these contracts resulted in realized gains of $93,178.

In Q1 2012, the Company, in an attempt to mitigate the impact of future fluctuations in interest rates on its outstanding debt, entered into a swap contract fixing the base interest rate on $20 million of banker's acceptance borrowings as outlined below. These rates are, under the Company's credit facility, subject to additional stamping fees from 2.00% to 3.50% depending on the debt to cash flow ratio, as therein defined, and as calculated at the Company's most recent quarter end. Recently, Canadian short term interest rates have remained relatively stable. As a result, the Company has recorded losses against its interest rate hedge and may, if rates do not increase, realize further losses on this contract in the future. During Q4 2012 the Company realized a loss of $16,606 on this contract and for 2012 the Company realized a loss $45,531 on this contract.

For the year ended December 31, 2012, the Company recorded a net gain of $4.1 million on its commodity price and interest rate financial contracts, of which $93,178 has been recorded as a realized gain.

At December 31, 2012, the Company recorded a current asset totaling $717,473 on its financial contracts, (a combination of $755,484 relating to a current asset on its commodity risk management and $38,011 relating to a current liability on the Company's interest rate risk management contract) and a long term liability of $499,771 (related to the Company's commodity risk management contracts).

The commodity contract valuations were based on a Canadian dollar WTI price of approximately $93.20 per barrel for 2013 and $93.00 per barrel for 2014. The future asset and liability will fluctuate and change at each reporting period with changes to the WTI future strip price in Canadian dollars and with changes to short term interest rates.

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 (as it did in November 2011). Currently, the Company has commodity contracts with terms as follows:

($Cdn.)

Commodity Sold	Volume Sold	Remaining Term	Pricing
Oil	300 bbl per day	January 1, 2013 - December 31, 2013	92.10 Cdn per bbl
Oil	400 bbl per day	January 1, 2013 - December 31, 2013	92.10 Cdn per bbl
Oil	300 bbl per day	January 1, 2013 - December 31, 2013	101.00 Cdn per bbl
Oil	300 bbl per day	January 1, 2013 - December 31, 2013	95.00 Cdn per bbl
Oil	200 bbl per day	February 1, 2013 - December 31, 2013	98.10 Cdn per bbl
Oil	300 bbl per day	January 1, 2014 - December 31, 2014	92.75 Cdn per bbl
Oil	600 bbl per day	January 1, 2014 - December 31, 2014	90.00 US per bbl
Oil	200 bbl per day	January 1, 2014 - December 31, 2014	92.00 US per bbl
Oil	200 bbl per day	January 1, 2014 - December 31, 2014	93.80 Cdn per bbl

Terms of the Company's interest rate swap are as follows:

($Cdn.)					
Subject of Contract	Remaining Term	Notional Quantity	Reference	Strike Price	Fair Value
30 day BA rate	January 1, 2013 - Feb 13, 2015	20,000,000	CAD - BA - CDOR	1.50%	(38,012)

Operating and Transportation

Operating costs include direct field costs such as contract operating fees and Company labor and benefits, electricity, fuel, property taxes, routine workovers and maintenance, processing and water disposal charges and transportation costs. Transportation costs reflect the cost of delivering production to the custody transfer point of the purchaser and are incurred primarily in British Columbia and Alberta.

	Three Months Ended December 31			**Year Ended December 31**		
(000's Cdn. $)	**2012**	2011	**% Change**	**2012**	2011	% Change
Canada						
Heavy oil	**234**	386	(39)	**1,016**	1,485	(32)
Light oil and NGL's	**4,431**	3,034	46	**17,534**	8,715	101
Natural gas	**949**	761	25	**4,538**	2,041	122
Total	**5,614**	4,181	34	**23,088**	12,241	89
US						
Heavy oil	**-**	-	-	**-**	-	-
Light oil and NGL's	**1,262**	933	35	**4,482**	3,582	25
Natural gas	**19**	4	447	**60**	4	1,576
Total	**1,282**	937	37	**4,542**	3,585	27
Total						
Heavy oil	**234**	386	(39)	**1,016**	1,485	(32)
Light oil and NGL's	**5,693**	3,967	43	**22,016**	12,297	79
Natural gas	**968**	764	27	**4,597**	2,045	125
Operating and transportation	**6,895**	5,118	35	**27,630**	15,827	75

Operating costs increased by $1.8 million or 35% in Q4 2012 versus Q4 2011 and by $11.8 million or 75% in 2012 over 2011. These increases were in line with production increases of 36% quarter over comparative quarter and 67% year over comparative year.

Per Boe	Three Months Ended December 31			Year Ended December 31		
($Cdn.)	**2012**	2011	% Change	**2012**	2011	% Change
Canada						
Heavy oil per barrel	**35.53**	33.96	5	**24.69**	23.96	3
Light oil and NGL's per barrel	**31.19**	30.75	1	**32.80**	26.69	23
Natural gas per mcf	**2.06**	2.20	(7)	**2.34**	2.71	(13)
Total per Boe	**24.88**	24.94	(0)	**25.69**	23.80	8
US						
Heavy oil per barrel	**-**	-	-	**-**	-	-
Light oil and NGL's per barrel	**9.77**	10.04	(3)	**10.20**	12.93	(21)
Natural gas per mcf	**0.46**	0.10	371	**0.40**	0.03	1,439
Total per Boe	**9.40**	9.46	(1)	**9.79**	11.96	(18)
Total						
Heavy oil per barrel	**35.53**	33.96	5	**24.69**	23.96	3
Light oil and NGL's per barrel	**20.99**	20.71	1	**22.61**	20.37	11
Natural gas per mcf	**1.92**	2.00	(4)	**2.21**	2.30	(4)
Operating and transportation per Boe	**19.05**	19.19	(1)	**20.28**	19.44	4

Operating costs for Q4 2012 averaged $19.05 per Boe versus $21.20 per Boe in Q3 2012 and $19.19 per Boe in Q4 2011. For 2012, operating costs averaged $20.28 per Boe versus $19.44 per Boe in 2011. Operating costs are particularly impacted by the timing of general field maintenance and routine workovers required to maintain or increase production and by the cost of electricity that since the Q4 2011 Property Acquisition has become a large component of operating expenses.

It is expected that with the addition of lower cost Bakken, North Dakota and Princess, Alberta production in 2013 and 2014, will offset operating cost increases such that field operating costs should stabilize in the target range of $18.00 to $20.00 per Boe.

Operating Netback

	Three Months Ended December 31			Three Months Ended December 31			
		2012			2011		Corporate
($Cdn.)	Canada	US	Corporate	Canada	US	Corporate	% Change
Heavy oil							
Revenue	**71.63**	**-**	**71.63**	81.85	-	81.85	**(12)**
Royalty	**(4.44)**	**-**	**(4.44)**	(15.93)	-	(15.93)	**(72)**
Operating and transportation	**(35.53)**	**-**	**(35.53)**	(33.96)	-	(33.96)	**5**
Operating netback per barrel	**31.67**	**-**	**31.67**	31.97	-	31.97	**(1)**
Light oil and NGL's							
Revenue	**70.13**	**81.01**	**75.31**	90.61	87.15	88.93	**(15)**
Royalty	**(9.33)**	**(23.68)**	**(16.17)**	(15.47)	(25.20)	(20.19)	**(20)**
Operating and transportation	**(31.19)**	**(9.77)**	**(20.99)**	(30.75)	(10.04)	(20.71)	**1**
Operating netback per barrel	**29.61**	**47.55**	**38.15**	44.39	51.91	48.04	**(21)**
Natural gas							
Revenue	**2.83**	**3.43**	**2.88**	2.76	4.52	2.93	**(2)**
Royalty	**0.01**	**(0.68)**	**(0.05)**	(0.23)	(0.78)	(0.28)	**(83)**
Operating and transportation	**(2.06)**	**(0.46)**	**(1.92)**	(2.20)	- 0.00	(2.00)	**(4)**
Operating netback per mcf	**0.78**	**2.29**	**0.91**	0.33	3.74	0.65	**40**
Boe							
Revenue	**52.04**	**77.85**	**61.76**	64.56	83.43	71.57	**(14)**
Royalty	**(5.98)**	**(22.66)**	**(12.26)**	(10.65)	(23.93)	(15.58)	**(21)**
Operating and transportation	**(24.88)**	**(9.40)**	**(19.05)**	(24.94)	(9.46)	(19.19)	**(1)**
Operating netback per Boe	**21.17**	**45.79**	**30.44**	28.97	50.05	36.80	**(17)**

During Q4 2012, the netback from heavy oil remained relatively consistent when compared to Q4 2011 as the 12% decrease in the average price received was offset by lower price sensitive royalties. Despite a 34% decrease in year over year production, operating costs remained relatively constant.

The netback from light oil and NGL's in Q4 2012 of $38.15 per barrel was reduced from Q4 2011 of $48.04 per barrel due to a lower average crude price (down 15%) primarily from increased differentials between market prices and the price received for the Company's quality of oil in both Canada and the US. In Canada, the average price received declined $20.48 per barrel from Q4 2011 reducing the netback to $29.61 per barrel from $44.39 per barrel in 2011. In the US, the average price received declined $6.14 per barrel reducing the netback to $47.55 per barrel in 2012 from $51.91 per barrel in 2011.

In December 2012, the differentials reached $31.55 per barrel in December 2012 for Bow River Hardisty crude (similar reference price to the Company's crude mix in Canada) and $5.00 per barrel for light Bakken crude in the US are the result of crude oversupply in both Canada and the US and limited take away capacity and refinery and pipeline maintenance.

Natural gas netbacks in Canada in Q4 2012 were up slightly from $0.33 per mcf in Q4 2011 to $0.78 per mcf and in the US, natural gas netbacks were $2.29 per mcf down from $3.74 in Q4 2011 due to volume adjustments.

In Canada, the Company's Q4 2012 overall operating netback declined 27% to $21.17 per Boe from $28.97 per Boe in Q4 2011, due to higher year over year differentials resulting in a lower average price received. In the US, the overall operating netback declined 9% to $45.79 per Boe from $50.05 per Boe in Q4 2011 as the price decline was somewhat offset by better grade of oil from Bakken production. Arsenal's corporate operating netback decreased 17% from $36.80 per Boe Q4 2011 to $30.44 per Boe in Q4 2012 due to a 14% reduction in the average price received per Boe that was offset by lower royalties per Boe. Corporate operating costs remained constant in the comparative quarters.

Realized commodity contract gains increased the operating netback by $1.75 in Q4 2012 to $32.19 per Boe as compared to a hedging loss in Q4 2011 $1.30 per Boe that reduced the corporate netback to $35.50 in Q4 2011.

	Year Ended December 31			Year Ended December 31			
		2012			2011		Corporate
($Cdn.)	**Canada**	**US**	**Corporate**	Canada	US	Corporate	**% Change**
Heavy oil							
Revenue	**70.70**	**-**	**70.70**	70.84	-	70.84	**(0)**
Royalty	**(9.90)**	**-**	**(9.90)**	(12.42)	-	(12.42)	**(20)**
Operating and transportation	**(24.69)**	**-**	**(24.69)**	(23.96)	-	(23.96)	**3**
Operating netback per barrel	**36.12**	**-**	**36.12**	34.46	-	34.46	**5**
Light oil and NGL's							
Revenue	**74.36**	**79.09**	**76.50**	83.54	85.55	84.47	**(9)**
Royalty	**(13.19)**	**(21.36)**	**(16.88)**	(13.06)	(23.49)	(17.85)	**(5)**
Operating and transportation	**(32.80)**	**(10.20)**	**(22.61)**	(26.69)	(12.93)	(20.37)	**11**
Operating netback per barrel	**28.37**	**47.53**	**37.01**	43.79	49.14	46.25	**(20)**
Natural gas							
Revenue	**2.22**	**3.13**	**2.28**	3.24	4.72	3.47	**(34)**
Royalty	**(0.07)**	**(0.59)**	**(0.11)**	(0.16)	(0.85)	(0.26)	**(60)**
Operating and transportation	**(2.34)**	**(0.40)**	**(2.21)**	(2.71)	0.03	(2.30)	**(4)**
Operating netback per mcf	**(0.19)**	**2.14**	**(0.03)**	0.38	3.90	0.91	**(103)**
Boe							
Revenue	**52.26**	**75.89**	**60.31**	66.33	81.24	71.82	**(16)**
Royalty	**(8.45)**	**(20.41)**	**(12.52)**	(10.02)	(22.10)	(14.47)	**(13)**
Operating and transportation	**(25.69)**	**(9.79)**	**(20.28)**	(23.80)	(11.96)	(19.44)	**4**
Operating netback per Boe	**18.12**	**45.69**	**27.50**	32.51	47.18	37.91	**(27)**

The netback from heavy oil in 2012 of $36.12 per barrel was slightly higher than the netback from heavy oil in 2011 of $34.46 per barrel. Lower royalties per Boe contributed to this slight increase.

The operating netback from light oil and NGL's in Canada decreased in 2012 by $15.42 per barrel to $28.37 per barrel from $43.79 per barrel in 2011. A lower average price received per Boe and higher operating costs were responsible for this decline. In the US, the operating netback from light oil decreased $1.61 per Boe due to a slightly lower average price received per Boe offset by lower royalties and lower operating costs per Boe.

Natural gas netbacks in Canada for 2012 were negative ($0.19) per mcf due to lower prices negating the decrease in royalty and operating expenses per mcf. In the US, lower prices reduced the natural gas operating netback to $2.14 per mcf from $3.90 per mcf in 2011.

Arsenal's corporate operating netback decreased 27% from $37.91 per Boe in the 2011 to $27.50 per Boe in 2012 due mainly to a decline in average price received. In Canada, the operating netback declined 44% to $18.12 per boe and in the US, the operating netback declined 3% to $45.69 per Boe.

Realized commodity contract gains for 2012 increased the operating netback by $0.07 per Boe to $27.57 while realized commodity contract gains increased the operating netback in 2011 by $4.12 per Boe to $42.03 per Boe for 2011.

General and Administrative

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2012**	2011	% Change	**2012**	2011	% Change
Gross expenditures	**1,551**	1,322	17	**6,615**	5,579	19
Overhead recovery	**(469)**	(413)	13	**(1,767)**	(963)	83
Capitalized overhead	**(79)**	(161)	(51)	**(715)**	(644)	11
Net general and administrative expense	**1,002**	748	34	**4,133**	3,972	4
Net general and administrative per boe	**2.77**	2.80	(1)	**3.03**	4.88	(38)

For Q4 2012, gross general and administrative expenditures were higher by $228,460 or 17%, when compared to Q4 2011. On a net basis, general and administrative expenditures increased by $254,585. For the year ended December 31, 2012, gross general and administrative expenditures increased by $1,036,002 when compared to 2011. Net general and administrative expenditures for year ended 2012 increased by $161,198 when compared to 2011.

2012 gross expenditures on general and administrative expenditures increased as salaries and benefits were up due to the higher number of consultants and employees required to integrate and operate the assets acquired in the Q4 2011 Property Acquisition and to normal annual industry adjustments to employee salaries and benefits. The Company also upgraded and added to its internal systems, experienced higher audit fees, higher reserve evaluation fees, higher filing fees resulting from a higher number of shares outstanding, and higher consulting fees related to increased activity.

Overhead recovery increased in Q4 2012 from Q4 2011 due to the increase in the dollar value of operated capital projects and the increase in the number of operated wells**.**

The Company capitalized overhead of salary, bonus and benefits for employees directly related to exploration and development activities. For the year ended 2012, the Company's capitalized overhead, excluding share based compensation, increased to $714,706 versus $644,000.

On a Boe basis, general and administrative costs for Q4 2012 remained virtually unchanged from Q4 2011 at $2.77 per Boe down from $2.80 per Boe in Q4 2011. For the year ended December 31 2012, net general and administrative expenses were $3.03 per Boe versus $4.88 per Boe in the year ended December 31, 2011. Higher gross costs were offset by an increase in overhead recovery and capitalized general and administrative expenditures. Per Boe costs were reduced by increased production.

General and administrative expenses should decrease on a Boe basis in 2013 as production is added without significant incremental increase in general and administrative expenses.

Interest and Other Financing Charges

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2012**	**2011**	% Change	**2012**	**2011**	% Change
Interest and other charges	**590**	381	55	**2,282**	934	144
Per Boe	**1.63**	**1.43**	14	**1.67**	**1.15**	46

Interest and other financing charges include interest, bank charges, facility review and renewal fees and other charges paid on the Company's credit facility and other interest costs.

Interest and other financing charges increased 55% in Q4 2012 to $589,622 or $1.63 per Boe when compared to Q4 2011. For the year ended December 31, 2012, interest and other financing charges increased 144% to $2.3 million or $1.67 per Boe compared to the year ended December 31, 2011. The increases in 2012 were due to the Q4 2011 Property Acquisition of $38.6 million funded entirely with bank borrowings. In addition, higher interest

charges are related to borrowings to drill North Dakota Bakken high working interest operated wells and for partner drilling. The Company's credit facility increased during 2011 from $40 million in early 2011 to $60 million in May 2011 and in November 2011 to $75 million. In Q1 2013, the facility was increased to $85 million. The next review date of the credit facility is May 31, 2013.

The average borrowing balance for Q4 2012 was $61.4 million versus $28.9 million for Q4 2011. For 2012, the average borrowing balance was $57.4 versus an average borrowing balance of $11.1 million for 2011 (see Credit Facility).

Transaction Costs

	Three Months Ended December 31			Year Ended December 31		
($Cdn.)	**2012**	**2011**	**% Change**	**2012**	**2011**	**% Change**
Transaction costs	**1,019**	614	66	**1,132**	614	85
Per boe	**2.82**	**2.30**	22	**0.83**	**0.75**	10

In November 2011, the Company completed the Q4 2011 Property Acquisition for $38.6 million. In addition to the acquisition price, the Company incurred acquisition, transaction and integration costs related to the purchase of totaling $726,815 of which $613,611 of costs were recorded in Q4 2011 and $113,204 of costs were recorded in Q1 2012.

In Q4 2012, the Company undertook an exercise to analyze efficient alternatives by which excess cash flow from the Company's North Dakota properties could be returned to shareholders. Costs related to this exercise for legal, accounting and financial advice totaled $1.4 million in the current quarter.

These costs were offset by $380,803 of cost recovery related to prior transactions.

Depletion and Depreciation

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2012**	2011	% Change	**2012**	2011	% Change
Depletion and depreciation	**6,605**	4,558	45	**24,552**	12,894	90
Per boe	**18.25**	17.09	7	**18.02**	15.84	14

A 36% increase in production and decreased reserves in the US based on a narrower type well sample for North Dakota wells resulted in an increase in depletion and depreciation to $6.6 million or $18.25 per Boe in Q4 2012 versus $4.6 million or $17.09 per Boe in Q4 2011. For the year ended December 31, 2012, production increased 67% from 2011, resulting in a 90% increase in depletion and depreciation to $24.6 million or to $18.02 per Boe from $12.9 million or $15.84 per Boe over 2011. Adjustments to existing reserves in Canada due to the low price forecast used by the evaluators and a narrower type well sample for North Dakota wells contributed to this increase.

In Canada, the depletion and depreciation rate per Boe in Q4 2012 was $17.58 versus $16.52 per Boe in Q4 2011. A reduction in reserves in Q4 2012 due to a lower engineering forecast price deck forecast accounts for the increase in the depreciation and depletion rate from Q4 2012. In the US, the depletion and depreciation rate increased to $19.37 per Boe in Q4 2012 versus $18.06 per Boe in the 2011 comparative quarter due to a reserve adjustment related to a tighter sampling of wells included in the reserve report.

In Canada on a Boe basis, depletion and depreciation decreased to $17.53 per Boe for 2012 period from $18.85 per Boe in 2011 due the the addition of reserves. In the US on a Boe basis, depletion and depreciation increased to $18.96 per Boe for 2012 from $10.68 per Boe in 2011 due to the reserve adjustment and factors noted above.

Accretion

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2012**	2011	% Change	**2012**	2011	% Change
Accretion	**225**	217	4	**930**	708	31

Accretion is the increase in the present value of the Company's decommissioning liabilities that are estimated based on current costs, inflated at a rate of 1.5% and discounted using a risk free interest factor of 2.4%. Accretion increased in Q4 2012 by 4% from Q4 2011 and by 31% in 2012 over 2011 due to the lower discount rate in 2012 (2.4%) from 2011 (2.8%) and due to accretion recorded in 2012 on the decommissioning liabilities assumed in the Q4 2011 Property Acquisition.

Property, Plant and Equipment Impairment

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2012**	2011	% Change	**2012**	2011	% Change
Property, plant and equipment impairment	**-**	1,000	(100)	**1,950**	5,500	(65)

The carrying amounts of the Company's property, plant and equipment are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the assets' recoverable amount is estimated based on certain industry value metrics. 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 assessment of the time value of money and the risks specific to the asset. The discount rates used by management to estimate future cash flows ranged from 10% for a high forward price, low risk light oil CGU to 20% for a low forward price, dry natural gas CGU. Production and timing of proved and probable reserves was determined by the Company's third party independent engineers. Management does not expect a significant difference between value in use and fair value less costs to sell.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its recoverable amount. Impairment losses are recognized in earnings.

On March 31, 2012, the impairment test indicated that due to low natural gas prices, the costs recorded in two natural gas CGU's exceeded the estimated recoverable amounts and accordingly, an impairment provision of $1.95 million was recognized. At March 31, 2011, poor well performance and higher than expected costs in one CGU resulted in an impairment of $2.5 million. At September 30, 2011, the costs recorded in a CGU's exceeded the estimated recoverable amounts an impairment provision of $2.0 million was recognized and at December 31, 2011 an additional $1.0 million impairment provision was recognized in the Company's heavy oil CGU due to negative reserve adjustments. Total impairment provision for 2011 of was $5.5 million.

As the recoverable amount of CGU's are sensitive to commodity prices, further impairment charges could be recorded in future periods. Alternatively, an improvement of commodity prices could reverse impairment charges recorded to date net of applicable depletion and depreciation charges.

Share-based Compensation

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2012**	2011	% Change	**2012**	2011	% Change
Share-based compensation expense	**227**	397	(43)	**1,079**	1,405	(23)

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.

In 2012, the Company granted 1,317,000 (December 31, 2011 – 4,840,000) options at a weighted average price of $0.52 (December 31, 2011 - $0.68) per share to directors, officers and employees. These options vest annually over three years and expire five years from date of grant.

Share-based compensation decreased 23% in 2012 over that recorded in 2011. 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 2010, 2011 and during 2012.

During 2012, the Company capitalized to property plant and equipment $285,739 (December 31, 2011 - $297,480) of share based compensation representing share based compensation relating to exploration and development overhead capitalized.

At December 31, 2012, the Company had 15,294,003 stock options outstanding at a weighted average price of $0.64 per share.

Loss (Gain) on Sale of Property

	Three Months Ended December 31			Year Ended December 31		
000's Cdn. $)						
	2012	**2011**	**% Change**	**2012**	**2011**	**% Change**
Loss (gain) on sale of property	**-**	-		**662**	(31)	

During Q1 2012, the Company disposed of its interest in two small high operating cost properties in Saskatchewan recognizing a loss of $1.5 million. The Company subsequently recorded gains on the sale of other properties, partially offsetting this loss. These sales have resulted in a total loss on the sale of properties for 2012 of $662,090.

Exploration and Evaluation Expenses

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2012**	2011	% Change	**2012**	2011	% Change
Exploration and evaluation expenses	**997**	831	20	**902**	5,663	(84)

Arsenal expenses all pre-license costs, seismic expenditures and dry hole costs. Proceeds from the sale of seismic are credited to exploration and evaluation expenses.

Deferred Tax Expense

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2012**	**2011**	% Change	**2012**	2011	% Change
Income tax expense	**948**	543	75	**3,784**	3,084	23

For the year ended December 31, 2012, the Company recorded a deferred income tax expense of $3.8 million, all of which related to US operations. High operating margins, low interest and other financing charges, and lower general and administrative expenses contributed to earnings in the US and therefore resulted in this deferred income tax expense provision. Canadian operations recorded a loss before tax of $6.0 million for 2012 as unrealized commodity contract gains were offset by low operating margins in Canada, property, plant and equipment impairment, a loss on the sale of a property and high depletion and depreciation charges.

At December 31, 2012, a deferred tax liability related to US operations of $9.1 million has been recorded up from $5.5 million recorded at December 31, 2011. In Canada, a deferred tax asset of $1.8 million as at December 31, 2012 is unchanged from December 31, 2011.

Arsenal does not expect to pay current tax in Canada or in the US in 2013 or 2014 based on current commodity price forecasts, expected capital expenditures and available tax pools. The availability and deductibility of existing tax pools will offset income from oil and gas operations and any realized commodity contract gains. Arsenal's tax pools are as follows:

	Year Ended Decmber 31, 2012	
(000's Cdn. $)	**Canada**	**US**
Cummulative Canadian Oil and Gas Property Expense	31,894	-
Cummulative Canadian Development Expense	11,210	-
Cummulative Canadian Exploration Expense	14,576	-
Undepreciated Capital Cost	28,971	9,946
Share Issue Costs	1,767	-
Non-capital Losses	14,356	20,793
Capital Loss and Other	3,581	-
	106,355	30,739

Funds from Operations and Loss and Comprehensive Loss

Funds from operations are calculated as net cash from operating activities before the change in non-cash operating working capital, seismic expenses and decommissioning obligations settled.

Funds From Operations	**Three Months Ended December 31**			**Year Ended December 31**		
(000's Cdn. $)	**2012**	**2011**	% Change	**2012**	2011	% Change
Net cash from operating activities	**4,918**	2,258	118	**29,700**	24,687	20
Seismic expenses (sales)	**988**	793	25	**898**	1,555	(42)
Transaction costs	**1,019**	614	66	**1,132**	614	84
Decommissioning obligations settled	**267**	311	(14)	**477**	819	(42)
Change in non-cash working capital	**2,807**	4,464	37	**(1,088)**	1,598	168
Funds from operations	**10,000**	8,441	18	**31,119**	29,273	6

Funds From Operations By Country	**Three Months Ended December 31**			**Year Ended December 31**		
(000's Cdn. $)	**2012**	2011	% Change	**2012**	2011	% Change
Canada	**4,795**	3,955	21	**12,910**	16,252	(21)
US	**5,205**	4,485	16	**18,210**	13,022	40
Funds from operations	**10,000**	8,441	18	**31,119**	29,274	6

Funds From Operations Per Boe	**Three Months Ended December 31**			**Year Ended December 31**		
($Cdn.)	**2012**	2011	% Change	**2012**	2011	% Change
Canada	**21.26**	23.59	(10)	**14.37**	31.60	(55)
US	**38.19**	45.28	(16)	**39.26**	43.45	(10)
Total	**27.63**	31.65	(13)	**22.84**	35.96	(36)

Funds From Operations and Net Loss	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $ except per share amounts)	**2012**	2011	Change	**2012**	2011	Change
Cash provided by operating activities	**4,918**	2,258	118	**29,700**	24,687	20
Funds from operations (1)	**10,000**	8,441	18	**31,119**	29,274	6
Per share						
Basic and diluted	**0.06**	0.05	20	**0.20**	0.18	8
Net loss	**(896)**	(4,051)	(78)	**(112)**	(2,545)	(96)
Per share						
Basic and diluted	**(0.01)**	(0.03)	(78)	0.00	(0.02)	-

Funds from operations for Q4 2012 totaled $10.0 million ($0.06 per share basic and diluted) or $27.63 per Boe versus $8.4 million ($0.05 per share basic and diluted) or $31.65 per Boe for Q4 2011. The average price received per Boe in the Q4 2012 decreased from Q4 2011 by 14% to $61.76 per Boe from $71.57 per Boe reducing the operating netback by $6.36 per Boe to $30.44 per Boe from $36.80 in Q4 2011. Interest and other financing charges reduced the cash netback by $1.63 in Q4 2012 versus $1.43 per Boe in Q4 2011. In addition, Q4 2012 included a realized commodity contract gain of $633,293 or $1.75 per Boe versus a Q4 2011 realized commodity contract loss of $346,955 or $1.30 per Boe. Crude prices decreased during the period due to lower WTI prices and higher differentials.

For 2012, funds from operations increased 6% to $31.1 million ($0.20 per share basic and diluted) or $22.84 per Boe versus $29.3 million ($0.18 per share basic and diluted) or $35.96 per Boe for 2011. The Company's operating netback in 2012 decreased by 27% to $27.50 per Boe from $37.91 per Boe in 2011. Realized hedging gains added $4.12 per Boe in 2011 versus $0.07 per Boe in 2012. Interest and other financing charges reduced the cash netback by $1.67 in 2012 versus $1.15 per Boe in 2011. General and administrative expenses for 2012 dropped 38%, adding $1.85 per Boe to the cash netback while interest and other financing charges increased $0.52 per Boe to $1.67 per Boe in 2012.

The Company had a net loss for Q4 2012 of $896,230 ($0.01 per share basic and diluted) versus net loss of $4.1 million ($0.03 per share basic and diluted) in Q4 2011. Production in Q4 2012 increased while operating margins declined by 17%. The Company recorded a net commodity contract loss (realized and unrealized) of $460,297 in Q4 2012 versus a loss in the Q4 2011 of $4.1 million.

For the year ended December 31, 2012, the Company recorded a net loss of $112,446 ($nil per share basic and diluted) versus net loss of $2.5 million ($0.02 per share basic and diluted) for 2011 due partially to gains on commodity contracts and increased production. Production in 2012 increased 67% while operating margins (due to higher differentials and lower prices) declined in 2012 by 27%. In addition, interest and other financing expenses, transaction costs, depreciation and depletion all increased while exploration and evaluation expenses decreased. In addition, due to the strengthening of the Canadian dollar, the Company recorded a foreign exchange loss on its US intercompany receivable in the year ended December 31, 2012 versus a gain in the year ended December 31, 2011.

Net Loss Per Boe

	Three Months Ended December 31		Year Ended December 31	
($Cdn.)	**2012**	2011	**2012**	2011
Oil and gas revenue	61.76	71.57	60.31	71.82
Royalties	(12.26)	(15.58)	(12.52)	(14.47)
Operating and transportation	(19.05)	(19.19)	(20.28)	(19.44)
Operating Netback	**30.44**	**36.80**	**27.50**	**37.91**
Realized gain (loss) on risk management contracts	1.75	(1.30)	0.07	4.12
General and administrative	(2.77)	(2.80)	(3.03)	(4.88)
Interest and other finance charges	(1.63)	(1.43)	(1.67)	(1.15)
Realized foreign exchange gain (loss)	(0.16)	0.38	(0.02)	(0.05)
Cash flow netback	**27.63**	**31.65**	**22.84**	**35.96**
Unrealized gain (loss) on risk management contracts	(3.02)	(14.16)	2.93	(2.89)
Depletion and depreciation	(18.25)	(17.09)	(18.02)	(15.84)
Accretion	(0.63)	(0.81)	(0.68)	(0.87)
Property, plant and equipment impairment	-	(3.75)	(1.43)	(6.76)
Exploration and evaluation expense	(2.73)	(3.11)	(0.66)	(6.96)
Gain (loss) on sale of property and equipment	-	-	(0.49)	0.04
Share-based compensation	(0.63)	(1.49)	(0.79)	(1.73)
Transaction costs	(2.82)	(2.30)	(0.83)	(0.75)
Foreign exchange gain (loss)	0.59	(2.09)	(0.17)	0.46
Deferred tax expense	(2.62)	(2.04)	(2.78)	(3.79)
Net loss per Boe	**(2.48)**	**(15.19)**	**(0.08)**	**(3.13)**

Comprehensive Loss

The Company's comprehensive income (loss) includes unrealized foreign exchange gains and losses resulting from the translation into Canadian dollars of the Company's US subsidiary. Due to the strengthening of the Canadian dollar, net loss for the year ended December 31, 2012 was increased as a consequence of a translation loss on foreign operations by $179,377 (gain of $47,133 for 2011).

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(000's Cdn. $ except per share amounts)	2012	2011	2010
Oil and gas revenue	82,168	58,466	43,666
Funds from operations	31,119	29,374	17,872
Net loss	(112)	(2,545)	(6,291)
Income (loss) per share, basic and diluted	-	(0.02)	(0.05)
Total assets	182,457	170,986	92,596
Total debt	68,492	55,752	18,788
Shares outstanding, end of year	155,948	157,282	140,812

Funds from operations are calculated as net cash from operating activities before the change in non-cash operating working capital, seismic expenses, transaction costs and decommissioning obligations settled.

Summary of Quarterly Results

	2012				2011			
(000's Cdn. $)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Production (Boe/d)	3,934	3,694	3,555	3,707	2,899	2,185	1,826	2,002
Oil and gas revenue	22,351	20,175	18,444	21,199	19,089	15,028	12,730	11,619
Net income (loss)	(896)	(1,474)	7,030	(4,773)	(4,051)	6,434	3,012	(7,940)
Per share - basic and diluted ($)	(0.01)	(0.01)	0.04	(0.03)	(0.03)	0.04	0.02	(0.05)
Funds from operations	10,000	7,782	6,538	6,799	8,441	11,426	4,302	5,106
Per share - basic and diluted ($)	0.06	0.05	0.04	0.04	0.05	0.05	0.03	0.03
Total assets	182,457	179,402	174,726	166,762	170,986	107,432	97,040	101,006
Total debt	68,492	64,386	60,054	56,706	55,752	9,240	9,932	6,871
Shares outstanding	155,948	156,414	156,194	156,294	157,282	135,124	161,761	163,314

Notes: Funds from operations are calculated as net cash from operating activities before seismic expenses, transaction costs, the change in non-cash operating working capital and decommissioning obligations settled.

Total debt excludes risk management contracts whether assets or liabilities

Arsenal's quarterly results have fluctuated significantly in the past eight quarters due to a variety of factors that include the Q4 2011 Property Acquisition, commodity price and production swings, the recognition of realized and unrealized gains and losses in risk management contracts, the timing of drilling and completions particularly in the US and in Alberta at Evi and Princess, the rationalization of properties and operating costs and the shutting-in of some natural gas production due to low prices. Arsenal has been and expects to continue to focus on properties amenable to waterflood and to rationalize its asset base focusing on properties with a long reserve life and 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 property dispositions and property shut-ins, the movement in commodity prices particularly for oil, the differentials in medium, heavy oil and North Dakota oil and the timing of drilling programs in North Dakota and Canada. With the establishment and maintenance of a core low decline property base coupled with the continuing implementation of operational efficiencies, a more stable commodity market and continued drilling success in North Dakota and Alberta, 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
- transporting, 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 December 31, 2012 with a fixed term are as follows:

(000's Cdn. $)	2013	2014	2015	2016	2017
Firm service transportation commitments	269	258	226	177	18
Lease of office premises	516	516	516	516	301
Office equipment lease	11	7	7	1	-
Field equipment leases	47	16	-	-	-
Total	**843**	**797**	**749**	**694**	**318**

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

Select Financial Information by Country

For The Year Ended December 31, 2012 (000's Cdn. $)	Canada	U.S	Total
Production (Boe/d)	2,455	1,268	3,723
Oil and gas revenue	46,963	35,205	82,168
Income (loss) before income taxes	(5,961)	9,633	3,672
Income (loss) after income taxes	(5,961)	5,850	(112)
Operating income	16,279	21,195	37,474
Exploration and evaluation assets (as at Dec 31, 2012)	10,754	-	10,754
Property, plant and equipment (as at Dec 31, 2012)	99,109	58,030	157,139
Capital expenditures	6,484	29,606	36,091
Exploration and evaluation expenditures	6,590	-	6,590
Property acquisitions	-	-	-
Property dispositions	(1,928)	-	(1,928)

For The Year Ended December 31, 2011 (000's Cdn. $)	Canada	U.S	Total
Production (Boe/d)	1,409	821	2,230
Oil and gas revenue	34,116	24,350	58,466
Operating income	16,721	14,140	30,862
Income (loss) before income taxes	(9,564)	10,103	539
Income (loss) after income taxes	(8,771)	6,226	(2,545)
Exploration and evaluation assets (as at Dec. 31, 2011)	9,100	-	9,100
Property, plant and equipment (as at Dec 31, 2011)	108,386	37,808	146,194
Capital expenditures	7,392	23,715	31,107
Exploration and evaluation expenditures	9,364	-	9,364
Property acquisitions	38,575	-	38,575
Property dispositions	(622)	-	(622)

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

Segmented Statement of Operations by Country

Year Ended December 31, 2012 (000's Cdn. $)	Canada	United States	**Total Company**
Revenue			
Petroleum and natural gas	46,963	35,205	**82,168**
Royalties	(7,596)	(9,468)	**(17,064)**
	39,367	25,737	**65,104**
Realized loss on risk management contracts	93	-	**93**
Unrealized loss on risk management contracts	4,458	(465)	**3,993**
	43,918	25,272	**69,191**
Expenses			
Operating and transportation	23,088	4,542	**27,630**
General and administrative	2,426	1,707	**4,133**
Exploration and evaluation	902	-	**902**
Property, plant and equipment impairment	1,950	-	**1,950**
Depletion and depreciation	15,756	8,796	**24,552**
Share-based compensation	1,078	-	**1,078**
Loss (gain) on sale of property	1,415	(753)	**662**
	46,615	14,292	**60,907**
Financial items:			
Interest and other financing charges	1,003	1,279	**2,282**
Accretion	862	68	**930**
Transaction costs	1,132	-	**1,132**
Foreign exchange loss realized	33	-	**33**
Foreign exchange loss unrealized	233	-	**233**
	3,264	1,347	**4,611**
Loss before income taxes	(5,961)	9,633	**3,672**
Income taxes			
Deferred income tax	-	3,784	**3,784**
Net loss	(5,961)	5,850	**(112)**

Year Ended December 31, 2011			**Total**
(000's Cdn. $)	Canada	United States	**Company**
Revenue			
Petroleum and natural gas	34,116	24,350	**58,466**
Royalties	(5,153)	(6,624)	**(11,777)**
	28,963	17,726	**46,688**
Realized gain (loss) on risk management contracts	2,438	919	**3,357**
Unrealized gain (loss) on risk management contracts	(2,807)	452	**(2,355)**
	28,593	19,097	**47,690**
Expenses			
Operating and transportation	12,241	3,585	**15,827**
General and administrative	2,515	1,457	**3,972**
Exploration and evaluation	5,663		**5,663**
Property, plant and equipment impairment	5,500	-	**5,500**
Depletion and depreciation	9,692	3,202	**12,894**
Property acquisition costs	614	-	**614**
Share-based compensation	1,405		**1,405**
Gain on sale of property	(31)	-	**(31)**
	37,599	8,244	45,843
Financial items:			
Interest and other financing charges	354	580	**934**
Accretion	539	170	**708**
Foreign exchange gain realized	(334)	-	**(334)**
Foreign exchange loss unrealized		-	**-**
	558	750	**1,308**
Income (loss) before income taxes	(9,564)	10,103	**539**
Income taxes			
Deferred income tax (reduction)	(793)	3,877	**3,084**
Net income (loss)	(8,771)	6,226	**(2,545)**

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

Bank Loan, Liquidity and Capital Resources

Capital Management

In order to continue the Company's ongoing exploration and development program, the Company needs to be conscious of and work towards maintaining 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, Canadian crude differentials, 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 shareholders' equity, its bank debt 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 a portion of the Company's debt and production, by closely monitoring expenses, by accurately estimating capital expenditures on projects, by closely monitoring and scrutinizing the results of its capital expenditure program and by scheduling 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, transaction costs, decommissioning obligations settled and seismic 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 operational items. The Company's goal is to target this ratio at 1.50:1 but the ratio can and will fluctuate based on the timing of property transactions, commodity prices and on the level of exploratory and development drilling activity particularly in the US. 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 and any other instance when the ratio is not within the target range 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, at least quarterly, when actual results are realized and compared to budget and when critical factors change. 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 December 31, 2012, the Company's net debt to annualized funds flow (Q4 2012 funds from operations annualized) ratio was 1:71:1 and its debt to equity ratio was 1.24:1. The debt to annualized funds flow ratio at December 31, 2012 was higher than the targeted range as a result of $40.5 million (net of dispositions) spent primarily in North Dakota and at Princess, Alberta exceeding funds from operations of $31.1 million. The Company did not issue equity in 2012 other than proceeds of $120,470 on the exercise of stock options.

In late 2012 and in early 2013, the crude differentials in Canada had increased due to excess crude supply and limited pipe and rail take away capacity. US differentials, however, were quite normal. These Canadian constraint problems are improving and are slowly returning to more normal levels. In response to these high differentials on Canadian production, the Company has elected to defer its Canadian drilling program to Q3 2013 and to bring forward its North Dakota drilling program to Q1 2013 from Q3 2013. Because of this, debt at March 31, 2013 is expected to increase from December 31 2012 but should reduce to more acceptable levels by mid to late 2013.

At December 31, 2012, the debt to equity ratio was also higher than the targeted ratio. This is a result of adjustments on the conversion to IFRS, to recent property fair value assessments resulting in impairments in Canada and to recording share based compensation. In addition, the mark to market valuation of the Company's commodity contracts causes fluctuations in earnings. Returning the Company to profitable operations should address the deviance from the target ratio going forward. The Company did not issue equity in 2012. Key factors that will determine when the Company will be able to return to within its established guidelines are the state of equity markets, production rates from drilling, commodity (particularly crude) prices and the magnitude and

timing of capital requirements to drill and complete wells in the Bakken and Three Forks plays in North Dakota and at Princess in Alberta.

(000's Cdn. $)	December 31, 2012
Bank loan	62,447
Working capital deficiency *(excluding risk management contracts)*	6,045
Total debt	68,492
Annualized funds from operations	39,999
Net debt to annualized funds flow ratio	**1.71**
Shareholders' Equity	55,027
Debt to equity	**1.24**

Credit Facility

In January 2013, the syndicate of bankers increased the facility to $85 million with all terms and conditions relating to the facility remaining unchanged. The next review date is May 31, 2013.

At December 31, 2012, debt under the credit facility amounted to $62.4 million up from $57.7 million at September 30, 2012 and from $52.1 million at December 31, 2011. Debt includes $11.0 million of US dollar denominated Libor borrowings ($ Cdn. $10.9 million). Total debt (including working capital deficiency) was $68.5 million at December 31, 2012.

The Company has a financial covenant that, without the written permission of the syndicate, would result in a breach of the agreement. The Company cannot permit the working capital ratio (as defined in the agreement to include the unutilized portion of the facility) to fall to below 1 : 1.

At December 31, 2012, the Company was in compliance with its working capital covenant.

The Company has attempted to mitigate the impact of future fluctuations in interest rates on its outstanding debt by entering into a swap contract fixing the base interest rate on $20 million of banker's acceptance borrowings as outlined below. These rates are, under the Company's credit facility, subject to additional stamping fees from 2.00% to 3.50% depending on the debt to cash flow ratio, as defined, and as calculated at the Company's most recent quarter end. At December 31, 2012, the Company recorded a liability of $38,012 under this contract.

($Cdn.)					
Subject of Contract	Remaining Term	Notional Quantity	Reference	Strike Price	Fair Value
30 day BA rate	January 1, 2013 - Feb 13, 2015	20,000,000	CAD - BA - CDOR	1.50%	(38,012)

Liquidity

Crude prices (net to the Company) in Canada have recently again been subject to large differentials, and while fluctuating somewhat, a return to more normal levels is expected in Q3 2013. US crude differentials fluctuated in 2012 but are now acceptable, in the $5.00 per barrel range.

These differentials particularly in Canada but also in the US are capable of wide swings depending on supply, take away capacity and refinery turnarounds, maintenance or other disruptions. Crude prices in the US, particularly for Arsenal's Bakken production, have improved and are only slightly discounted from WTI prices. WTI future prices

for 2013 and 2014 have been in the $90.00 - $95.00 US per barrel range with Canadian light oil (40 degree) in the $85.00 - $90.00 per barrel range. Natural gas prices have recovered slightly in the past few months but remain well below prices in the prior year. Natural gas in the US is in the $3.50 - $4.00 per mmbtu range with Canadian AECO in the $3.25 - $3.50 per GJ range. Decreased natural gas prices due to oversupply combined with lower crude prices due to increased Canadian differentials have resulted in lower than forecast funds from operations resulting in a lower share price and restricted access to capital. Natural gas prices are improving and the differentials from posted prices have improved.

Access to equity markets for most oil weighted companies can be available, albeit at a discount to trading prices and at a significant discount to net asset value. Given the current commodity prices and the improvement in 2013 differentials in the US, the Company can generate the financial resources necessary to undertake a 2013 capital expenditure program and is expecting a reasonable 2014 program. This capital program may be greater than the Company's funds from operations. Even with a capital program that is higher than the Company's funds from operations, the Company should be able remain within an industry acceptable level of debt and within an acceptable range of its targeted debt to annualized funds flow from operations ratio of 1.50 : 1. In the event that commodity prices, differentials, interest or exchange rates, or other factors negatively impact funds flow from operations, the Company, while it has the ability to access equity markets, anticipates that it will reduce the capital program to safeguard its capital base with the goal of having debt staying not only within the Company's credit facility but also within an acceptable range of its targeted debt to forward annualized funds flow from operations ratio.

In order to further ensure that funds are available to assist in the financing of the Company's capital program and to ensure positive returns from the Company's capital development and acquisition program, the Company utilizes commodity hedges to lock in commodity prices. In 2012, the Company entered into a number of crude oil commodity contracts covering 2012, 2013 and 2014. In order to solidify cash flow from operations, the Company has entered into crude oil commodity contracts for 2013 and 2014. Terms of these contracts are as follows:

($Cdn.)

Commodity Sold	Volume Sold	Remaining Term	Pricing
Oil	300 bbl per day	January 1, 2013 - December 31, 2013	92.10 Cdn per bbl
Oil	400 bbl per day	January 1, 2013 - December 31, 2013	92.10 Cdn per bbl
Oil	300 bbl per day	January 1, 2013 - December 31, 2013	101.00 Cdn per bbl
Oil	300 bbl per day	January 1, 2013 - December 31, 2013	95.00 Cdn per bbl
Oil	200 bbl per day	February 1, 2013 - December 31, 2013	98.10 Cdn per bbl
Oil	300 bbl per day	January 1, 2014 - December 31, 2014	92.75 Cdn per bbl
Oil	600 bbl per day	January 1, 2014 - December 31, 2014	90.00 US per bbl
Oil	200 bbl per day	January 1, 2014 - December 31, 2014	92.00 US per bbl
Oil	200 bbl per day	January 1, 2014 - December 31, 2014	93.80 Cdn per bbl

As a result of these crude commodity contracts, the Company has commodity contracts selling 1,500 barrels of oil per day for 2013 at an average price of approximately $95.26 Canadian per barrel and 1,300 barrels per day for 2014 at approximately $91.53 Canadian per barrel.

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

Share Capital

On June 16, 2011, the Company announced its intention to make a normal course issuer bid ("NCIB") that ended June 19, 2012. A total of 6,600,044 common shares at an average price of $0.65 per share were acquired under the bid. Of the shares purchased, 1,141,500 were purchased in 2012.

On July 5, 2012, the Company announced its intention to make a normal course issuer bid ("NCIB") that commenced July 9, 2012 and ends July 8, 2013. A total of 7,809,705 common shares may be acquired under the bid representing 5% of the common shares outstanding as of July 4, 2012. At December 31, 2012, 506,500 shares have been purchased under the current bid an average price of $0.54 per share plus expenses.

During the year ended December 31, 2012, 1,317,000 stock options were issued at an average price of $0.52. In addition, 313,333 stock options were exercised at an average exercise of $0.39 and 403,334 stock options expired at an average exercise price of $0.72.

At December 31, 2012, the Company had 155,947,594 common shares and 15,294,003 stock options at a weighted average price of $0.64 outstanding.

Common Shares

	Year Ended December 31, 2012		Year Ended December 31, 2011	
(000's)	Shares	$	Shares	$
Balance - beginning of period	157,282	136,860	140,812	122,609
Issued under prospectus offering	-	-	22,159	21,051
Share issue costs	-	1	-	(1,695)
Issued on exercise of options	313	120	1,343	561
Transferred from contributed surplus	-	99	-	470
Purchases under normal course issuer bid	(1,648)	(1,435)	(7,032)	(6,136)
Balance - end of period	**155,948**	**135,646**	**157,282**	**136,860**

Options

(000's)	**Year Ended December 31, 2012**	Year Ended December 31, 2011
Balance - beginning of period	**14,694**	12,755
Exercise of options	**(313)**	(1,343)
Options issued	**1,317**	4,840
Options forfeited or expired	**(403)**	(1,558)
Balance - end of period	**15,294**	14,694

As of the date of this MD&A, the Company has 157,136,760 common shares and 14,714,003 options outstanding.

	December 31, 2012 to March 18, 2013	
(000's)	**Common Shares**	**Options**
Balance - beginning of period	**155,948**	**14,694**
Issued pursuant to private placement	**2,604**	
Issued on exercise of puts on options	**-**	**(580)**
Purchases under normal course issuer bid	**(1,415)**	-
Balance - end of period	**157,137**	**14,114**

On March 13, 2013, the Company closed private placement issuing 2,604,166 common shares at $0.48 per share for gross proceeds before expenses of $1,250,000.

Capital Expenditures

Capital expenditures in Q4 2012 on property, plant and equipment totaled $8.7 million down from $10.8 million in Q4 2011. Expenditures in the US in Q4 2012 were primarily directed to drilling and completing non operated wells at Stanley. In Canada, expenditures were incurred to drill and complete one 100% working interest well at Princess in Alberta and on the waterflood project at Princess.

Expenditures on exploration and evaluation totaled $2.1 million in Q4 2012 compared to $2.8 million spent in Q4 2011. These expenditures were incurred to drill an exploratory well at Princess, Alberta that required production testing at quarter end.

Total capital expenditures on property, plant and equipment in the year ended December 31, 2012 totaled $36.1 million versus $31.1 million in the year ended December 31, 2011. In Canada ($6.5 million) capital was incurred on drilling, completion and recompletions at Princess, Provost, Evi and Edgerton and on water injection facilities and tie-ins particularly at Princess. Capital expenditures in the US ($29.6 million) were incurred to acquire land at Rennie Lake/Black Slough, to drill, complete, equip and tie-in two high working interest Bakken wells at Stanley in North Dakota and to participate in partner operated drilling and completions at both Stanley and at Lindahl in North Dakota.

Capital expenditures in Canada on exploration and evaluation during 2012 totaled $6.6 million and were incurred to purchase land at Princess, Columbia, and Galahad. No exploration and evaluation expenditures were incurred in the US.

During the year ended December 31, 2012, the Company sold its interest in five minor properties (the two largest being Dee Valley and Blackshire) for proceeds of $1.9 million.

Total Company

Property, Plant and Equipment

	Three Months Ended December 31		Year Ended December 31	
(000's Cdn. $)	**2012**	**2011**	**2012**	**2011**
Land	**552**	1,628	**1,782**	2,211
Drilling and completions	**5,811**	6,032	**28,405**	22,413
Capitalized general and administrative	**132**	257	**1,000**	941
Production equipment, facilities and tie-ins	**2,348**	2,932	**5,292**	5,824
Other	**(875)**	(2,566)	**1,194**	(600)
Total property plant and equipment additions	**7,968**	8,283	**37,673**	30,789
Non-cash additions	**702**	2,816	**(1,582)**	318
Total Property, Plant and Equipment Expenditures	**8,670**	11,099	**36,091**	**31,107**

Exploration and Evaluation

	Three Months Ended December 31		Year Ended December 31	
(000's Cdn. $)	**2012**	**2011**	**2012**	**2011**
Land	**1,828**	**1,907**	**2,810**	5,177
Drilling and completions	**251**	**908**	**3,780**	4,187
Total Exploration and Evaluation Expenditures	**2,079**	2,815	**6,590**	9,364

Property Acquisitions

	Three Months Ended December 31		Year Ended December 31	
(000's Cdn. $)	**2012**	**2011**	**2012**	**2011**
Total Property Acquisitions	-	38,575	-	38,575

Property Dispositions

Property Dispositions

	Three Months Ended December 31		Year Ended December 31	
(000's Cdn. $)	**2012**	**2011**	**2012**	**2011**
Total Property Dispositions	**-**	(23)	**(1,928)**	(622)

Seismic

	Three Months Ended December 31		Year Ended December 31	
(000's Cdn. $)	**2012**	**2011**	**2012**	**2011**
Seismic expenditures	**893**	793	**1,029**	1,555
Proceeds on sale of seismic	**95**	**-**	**(131)**	-
Total Seismic	**988**	793	**898**	1,555

CANADA

Property, Plant and Equipment

	Three Months Ended December 31		Year Ended December 31	
(000's Cdn. $)	**2012**	**2011**	**2012**	**2011**
Land	**52**	302	**213**	787
Drilling and completions	**1,510**	505	**3,321**	2,764
Capitalized general and administrative	**92**	257	**748**	941
Production equipment, facilities and tie-ins	**976**	1,308	**2,591**	3,182
Other	**(1,009)**	168	**693**	1,320
Total property plant and equipment additions	**1,621**	2,540	**7,566**	8,994
Non-cash additions	**836**	82	**(1,081)**	(1,602)
Total Property, Plant and Equipment Expenditures	**2,457**	2,622	**6,485**	**7,392**

Exploration and Evaluation

	Three Months Ended December 31		Year Ended December 31	
(000's Cdn. $)	**2012**	**2011**	**2012**	**2011**
Land	**1,828**	1,907	**2,810**	5,177
Drilling and completions	**251**	908	**3,780**	4,187
Total Exploration and Evaluation Expenditures	**2,079**	2,815	**6,590**	**9,364**

Property Acquisitions

	Three Months Ended December 31		Year Ended December 31	
(000's Cdn. $)	**2012**	**2011**	**2012**	**2011**
Total Property Acquisitions	-	38,575	-	**38,575**

Property Dispositions

	Three Months Ended December 31		Year Ended December 31	
(000's Cdn. $)	**2012**	**2011**	**2012**	**2011**
Total Property Dispositions	**-**	(23)	**(1,928)**	(622)

Seismic

	Three Months Ended December 31		Year Ended December 31	
(000's Cdn. $)	**2012**	**2011**	**2012**	**2011**
Seismic expenditures	**893**	**793**	**1,029**	**1,555**
Proceeds on sale of seismic	**95**	-	**(131)**	-
Total Seismic	**988**	793	**898**	**1,555**

USA

Property, Plant and Equipment

	Three Months Ended December 31		Year Ended December 31	
(000's Cdn. $)	**2012**	**2011**	**2012**	**2011**
Land	**500**	1,326	**1,569**	1,424
Drilling and completions	**4,301**	5,527	**25,084**	19,649
Capitalized general and administrative	**40**	-	**252**	-
Production equipment, facilities and tie-ins	**1,372**	1,624	**2,701**	2,642
Other	**134**	(2,734)	**501**	(1,920)
Total property plant and equipment additions	**6,347**	5,743	**30,107**	21,795
Non-cash additions	**(134)**	2,734	**(501)**	1,920
Total Property, Plant and Equipment Expenditures	**6,213**	8,477	**29,606**	**23,715**

Decommissioning Obligations

The Company's decommissioning obligations represent 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 decreases to the discount rates used, 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 increases in the discount rate used, property dispositions, decreases in estimated costs or changes to timing to abandon and reclaim wells and costs incurred in settlement of abandonment obligations. At December 31, 2012, the Company has recorded a decommissioning obligation of $37.4 million (December 31, 2011 - $37.3 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:

(000's Cdn. $)	**Year Ended December 31, 2012**	Year Ended December 31, 2011
Balance at beginning of period	**37,326**	19,667
Obligations settled	**(477)**	(819)
Obligations acquired	**-**	18,703
Obligations disposed of	**(1,629)**	(436)
Obligastions incurred	**317**	622
Change in estimate	**978**	(1,214)
Foreign currency translation	**(72)**	94
Accretion expense	**930**	709
Balance at end of period	**37,373**	37,326

The total undiscounted amount of estimated cash flows required to settle the obligation is $51.5 million, which has been discounted for in the financial statements using a risk free rate of 2.4% (December 31, 2011 - 2.8%) and an inflation factor of 1.5% (December 31, 2011 - 1.5%) as at December 31, 2012.

Commitments and Contingencies

Outstanding lawsuits

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

Risk Factors

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

Commodity price risk

Commodity price risk is defined as fluctuations in crude oil, natural gas, and natural gas liquid prices. The Company uses financial derivative instruments as part of its risk management approach to manage commodity price fluctuations and stabilize funds from operations available for future development programs. The Company does not enter into derivative contracts for speculative purposes. At December 31, 2012, the Company had in place seven crude oil commodity contracts covering 2013 and 2014. In 2013, the Company added three additional crude oil commodity contracts for 2013 and 2014 (see Liquidity section of this MD&A).

Production risk

Production risk relates to the Company's ability to produce, process and transport crude oil and natural gas. To manage this risk to an acceptable level, the Company performs regular and proactive maintenance on its wells, facilities and pipelines. The Company operates approximately 85% of its production, which affords greater control over operations. Approximately 37% of the Company's Q4 2012 production is in the United States.

Natural Decline and Reserve Replacement Risk

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

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

Environmental Health and Safety Risk

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

Regulation, Tax and Royalty Risk

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

Capital Market Risk

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

For a more detailed discussion of the Risk Factors, refer to the Company's Annual Information Form filed 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 consolidated financial statements for the years ended December 31, 2012 and 2011. 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

Future accounting policies:

The Company has reviewed the following new and revised accounting pronouncements that have been issued but are not yet effective and determined that the following may have an impact on the Company's financial statements:

IFRS-9 Financial Instruments:

The IASB intends to replace IAS 39 Financial Instruments: recognition and Measurement with IFRS-9 Financial Instruments.

The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has two classification categories: amortized cost and fair value.

The Company intends to adopt IFRS 9 in its financial statements for the annual period beginning on January 1, 2015. The extent of the impact of the adoption of IFRS 9 has not yet been determined.

Consolidation, Joint Arrangements and Disclosures

(i) IFRS-10 Consolidated Financial Statements replaces IAS - 27 Consolidation and Separate Financial Statements and SIC -12 Consolidation – Special Purpose Entities. This standard provides a single model to be applied in control analysis for all investees including special purpose entities.

(ii) IFRS-11 Joint Arrangements replaces IAS 31 Interest in Joint Ventures and SIC 13 Jointly Controlled Entities – Non- Monetary Contributions by Venturers. IFRS 11 divides joint arrangements into two types, joint operations and joint ventures. Under a joint operation, parties have rights to the assets and obligations for the liabilities on the arrangement and account for their proportionate share of the assets, liabilities, revenues and expenses. Under a joint venture, parties have the rights to the net assets of the arrangement and account for the arrangement as an investment using the equity method.

(iii) IFRS-12 Disclosures of Interests in Other Entities, combines in a single standard the disclosure requirements for subsidiaries, associates and joint arrangements as well as unconsolidated structured entities.

(iv) IFRS-13 Fair Value Measurement, defines fair value, establishes a framework for measuring fair value and sets out disclosure requirements for fair value measurements. This standard defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

The above standards are effective for annual periods beginning on or after January 1, 2013 and must be adopted concurrently. The Company is currently assessing the expected impact, if any, that the adoption of these standards will have on its financial statements.

Presentation of Items of Other Comprehensive Income

In June 2011, the IASB issued an amendment to IAS 1, "*Presentation of Financial Statements*" ("IAS 1") requiring companies to group items presented within OCI based on whether they may be subsequently reclassified to profit or loss. This amendment to IAS 1 is effective for annual periods beginning on or after July 1, 2012 with full retrospective application. Early adoption is permitted. The extent of the impact of adoption of this amendment has not yet been determined.

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 year ended December 31, 2012 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 providing 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 IFRS. 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 year ended December 31, 2012 to material weaknesses in internal controls over financial reporting.