MANAGEMENT DISCUSSION AND ANALYSIS

SUMMARY OF FINANCIAL AND OPERATIONAL RESULTS

	Three Months Ended March 31	
(000'S Cdn. $ except per share amounts)	**2015**	**2014**
FINANCIAL		
Oil and gas revenue	**13,866**	27,606
Funds from operations	**15,760**	11,053
Per share - basic	**0.88**	0.69
Per share - diluted	**0.87**	0.69
Net income (loss)	**(466)**	1,028
Per share - basic	**(0.03)**	0.06
Per share - diluted	**(0.03)**	0.06
Total debt	**57,229**	74,294
Capital expenditures	**6,671**	12,189
Property acquisitions	-	**152**
Wells drilled - Oil	**0.89**	4.61
Common Share Trading Range		
High	**6.84**	6.58
Low	**3.05**	4.52
Close	**3.30**	6.57
Average daily volume	**26,758**	24,201
Shares outstanding - end of period	**17,897**	16,090
OPERATIONAL		
Daily production		
Heavy oil (bbl/d)	**40**	46
Medium oil and NGL's (bbl/d)	**1,698**	1,635
Light oil and NGLs (bbl/d)	**1,392**	1,298
Natural gas (mcf/d)	**5,648**	6,776
Oil equivalent (boe/d @ 6:1)	**4,071**	4,108
Realized commodity prices ($Cdn.)		
Heavy oil (bbl)	**42.20**	71.70
Medium oil and NGL's (bbl)	**41.16**	86.09
Light oil and NGLs (bbl)	**49.31**	96.60
Natural gas (mcf)	**2.46**	5.51
Oil equivalent (boe @ 6:1)	**37.85**	74.66
Netback ($ per boe)		
Revenue	**37.85**	74.66
Royalty	**(9.74)**	(14.66)
Operating and transportation	**(16.37)**	(21.29)
Operating netback per boe	**11.74**	38.71
General and administrative	**(3.01)**	(2.67)
Interest and other financing	**(1.46)**	(1.79)
Realized gain (loss) on risk management contracts	**35.84**	(4.18)
Other (FX and current tax)	**(0.08)**	(0.17)
Fund from operations per Boe	43.02	29.89

1 Funds from operations is not recognized by IFRS but it is used by the Company, investors, analysts, bankers and others to evaluate and compare oil and gas exploration, development and production entities. The Company determines funds from operations as net cash from operating activities before the net change in non-cash operating working capital, decommissioning obligations settled, exploration and evaluation expenses and transaction costs, if any. Funds from operations does not have a standardized measure prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other companies.

2 Funds from operations and net income (loss) per share basic are calculated based on the weighted average number of common shares outstanding during the respective periods. Funds from operations and net income (loss) per share diluted are calculated based on the weighted average number of common shares outstanding for the respective period adjusted for dilutive instruments (stock options and share awards).

3 Net debt includes bank borrowings, plus or minus working capital. Net debt excludes long term decommissioning obligations and risk management contracts (whether an asset or an obligation and whether classified as short or long term).

4 Funds from operations per Boe is funds from operations calculated on a Boe basis.

Q1 2015 Financial and Operating Highlights

As a result of the severe drop in crude prices that started in Q4 2014 and continue into 2015, the Company, in early 2015, took certain initiatives to maintain its financial strength and to protect and strengthen its balance sheet. These initiatives included deferring development drilling, as current margins were not sufficient to replace reserves produced, focusing on the Company's exploration program in order to bolster and improve the Company's development inventory for when prices and margins improve, reducing bonuses for employees, reducing director fees, freezing employee salaries and deferring drilling activities to the later part of 2015 to take advantage of "expected" higher prices to improve margins. Since then, the Company has reduced its head office head count, reduced or eliminated the use of consultants, reduced operating costs and reviewed and reduced other general and administrative expenses. The Company continues to watch crude prices and continues to monitor the economics of production, drilling and ongoing costs in order to maintain financial flexibility.

Dividends

On February 9, 2015, the Board of Directors declared a quarterly dividend of $0.03 per common share to shareholders of record on February 17, 2015. The dividend was paid on February 27, 2015. On May 4, 2015, in response to lower crude prices, operating margins and cash netbacks, the Board of Directors declared a reduced quarterly dividend of $0.02 per common share to shareholders of record on May 15, 2015 to be paid on May 29, 2015. Dividends in 2015 have returned to shareholders $823,260 of value in the form of cash or common shares to shareholders who participate in the Share Dividend Plan.

Shareholders wishing to participate in the Share Dividend Plan should contact their broker or intermediary or, in the case of registered shareholders, contact our transfer agent, Alliance Trust Company, or visit our website to obtain the necessary enrolment forms.

Funds from Operations

Funds from operations (after realized commodity contract gains) for Q1 2015 totaled $15.8 million ($0.88 per share basic and $0.87 per share diluted) versus funds from operations in Q4 2014 of $16.9 million ($0.98 per share basic and $0.95 per share diluted) and $11.1 million ($0.69 per share basic and diluted) in Q1 2014.

Funds from operations in Q1 2015 increased from Q4 2014 due primarily to the monetization of the Company's 2015 crude hedge book that generated proceeds of $13.2 million as both production (down 14%) and the average price received per Boe (down 35%) declined. Funds from operations in Q1 2015 increased from Q1 2014 due to the monetization of the

Company's 2015 crude hedge book (proceeds of $13.2 million) as both production (down 1%) and the average price received per Boe (down 49%) declined.

On a Boe basis, the Company's operating margin decreased 70% to $11.74 per Boe for Q1 2015 from $38.71 per Boe realized in Q1 2014. During Q1 2015, the average price received declined 49% to $37.85 per Boe, royalties were down 34% and operating costs dropped 23%.

On a Boe basis, funds from operations increased 44% to $43.02 per Boe for Q1 2015 versus $29.89 per Boe realized in Q1 2014. During Q1 2015, realized gains on risk management contracts increased the funds from operations netback per Boe by $35.84 per Boe versus a loss in Q1 2014 of $4.18 per Boe. Other cash costs were in total generally comparable for the quarters.

Net Cash from Operating Activities

Net cash from operating activities in Q1 2015 totaled $17.1 million versus $7.6 million generated in Q1 2014. Changes in operating margins, exploration and evaluation expenses, funds realized on crude risk management contracts and foreign exchange and changes in non-cash working capital are largely responsible for these changes during the respective comparative periods.

Production

Production for Q1 2015 averaged 4,071 Boe per day (77% crude oil and NGL and 23% natural gas) versus 4,742 Boe per day in Q4 2014 (78% crude oil and NGL and 22% natural gas) and 4,108 Boe per day in Q1 2014 (73% crude oil and NGL and 27% natural gas).

Average production was down 14% from Q4 2014 and decreased in both Canada and the US. In Canada production was down at Princess a result of production curtailments due to facility constraints and in the US production was down as new wells in North Dakota experienced their normal decline during the quarter.

Net Debt

Net debt at March 31, 2015 was $57.2 million, down from $65.2 million at December 31, 2014. Net debt has decreased from December 31, 2014 due primarily to the monetizing of the Company's commodity risk management contracts that generated proceeds of $13.1 million.

Net Debt Reconciliation

(000's Cdn. $)	**Three Months Ended March 31**
Net debt December 31, 2014	**65,198**
Funds from operations	**(15,760)**
Additions to property, plant and equipment	**6,671**
Exploration and evaluation expenses	**1,666**
Dividends	**465**
Decommissioning liabilities settled	**87**
Foreign exchange gain on US cash held	**(180)**
Change in working capital and other items	**(918)**
Net debt March 31, 2015	**57,229**

In April 2015, the Company's syndicate of bankers commenced their review of the Company's yearend reserves and credit facility. Due to the severe decrease in crude prices in 2014 and that continue into this year, indications are that the credit facility limit will be reduced from $90 million and that the structure of the facility will change. Based on preliminary discussions and forecasts, management is of the opinion that the neither the limit reduction nor the change in the structure will put undue financial pressure on the Company during 2015. The review is expected to be completed by May 31, 2015.

Net Loss

The Company recorded a net loss in Q1 2015 of $466,316 or $0.03 per share basic and diluted versus income of $1.0 million or $0.06 per share basic and diluted in Q1 2014. Production decreased 14% from Q4 2014 and 1% from Q1 2014. Low crude prices during the quarter resulted in a 58% lower operating margin from Q4 2014 and a 70% lower operating margin from Q1 2014. In addition, increased exploration and evaluation expenses (up $688,963 from Q4 2014 and $1.0 million from Q1 2014), further contributed to the Q1 2015 loss.

Capital Expenditures

Capital expenditures for Q1 2015 to property, plant and equipment totaled $6.7 million down from $12.2 million in Q1 2014. Expenditures in Q1 2015 were incurred in Canada ($3.8 million) primarily to complete oil wells drilled in Q4 2014 and on facilities at Princess and on the completion of an oil well at Evi drilled in Q4 2014. Expenditures in Q1 2015 were incurred in the US, ($2.9 million) primarily to drill Bakken and Three Forks wells at Lindahl.

Normal Course Issuer Bid ("NCIB")

On March 27, 2014, the Company announced its intention to make a NCIB to commence April 1, 2014 and ending on March 31, 2015. During 2014, the Company acquired 40,900 common shares under the bid at an average cost of $7.24 per share plus expenses. No shares were acquired in Q1 2015.

Corporate Information

As of May 4, 2015, Arsenal has 17,896,761 common shares, 930,837 stock options and 241,200 share incentive (restricted and performance) awards outstanding. The Company's shares are listed and posted for trading on the Toronto Stock Exchange under the symbol "AEI" and in the US over the counter on the - OTCQX under the symbol "AEYIF".

In Canada, the Company operates under Arsenal Energy Inc. and had average production of 2,574 Boe per day for Q1 2015. In the US, the Company operates under its 100% indirectly owned subsidiary Arsenal Energy USA Inc. and had average production of 1,496 Boe per day for Q1 2015.

Basis of Presentation

The following is management's discussion and analysis ("MD&A") of Arsenal Energy Inc.'s ("Arsenal" or the "Company") unaudited operating and financial results for the three months ended March 31, 2015. It should be read in conjunction with the audited consolidated financial statements and related notes of the Company for the year ended December 31, 2014. Additional information regarding Arsenal's AIF and financial and operating results may be obtained on the internet at www.sedar.com.

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

Tables may not add due to rounding.

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

This MD&A is dated May 4, 2015.

Forward-Looking Statements

Certain statements contained within the Management's Discussion and Analysis constitute forward looking statements. These statements relate to future events or future performance. All statements other than statements of historical fact may be forward looking statements. Forward looking statements are often, but not always, identified by the use of words such as 'seek', 'anticipate', 'budget', 'plan', 'continue', 'estimate', 'expect', 'forecast', 'may', 'will', 'propose', 'project', 'predict', 'potential', 'targeting', 'intend', 'could', 'might', 'should', 'believe' and similar expressions or the negative of these terms or other comparable terminology and are generally intended to identify forward looking statements. These statements involve known and unknown risks, certainties and uncertainties and other factors that may cause actual results or events to differ materially from those anticipated or expected in such forward looking statements.

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 through exploration and development activities; and the continuation of the current tax and regulation regimes.

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

Boe Presentation

For the purpose of calculating unit costs, natural gas is converted to a 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 (“NGL”) in this MD&A include condensate, propane, butane and ethane and one barrel of NGL is considered to be equivalent to one barrel of crude oil equivalent (Boe).

Non-GAAP Measures

Within the MD&A, references are made to terms having widespread use in the oil and gas industry in Canada. The measures discussed are widely accepted measures of performance and value within the industry, and are used by investors and analysts to compare and evaluate oil and gas exploration and producing entities.

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

Funds from operations is not recognized by IFRS but it is used by the Company, investors, analysts, bankers and others to evaluate and compare oil and gas exploration and producing entities. The Company determines funds from operations as net cash from operating activities before the net change in non-cash operating working capital, decommissioning obligations settled, exploration and evaluation expenses and transaction costs. The Company's banker uses funds from operations (adjusted for the above and for interest and other financing charges and income taxes) 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 net cash 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 netback is funds from operations calculated on a Boe basis.

Operating income is calculated as revenue generated from oil and natural gas less royalties and operating and transportation expenses. Operating netback is operating income calculated on a Boe basis.

Boe production per day is calculated by dividing total production for the year or quarter by the number of days in the year or quarter as the case may be.

Net debt includes bank borrowings, plus or minus working capital. Net debt excludes long term decommissioning obligations and risk management contracts (whether an asset or an obligation and whether classified as short or long term).

Net Cash from Operating Activities and Funds from Operations

The following table compares net cash from operating activities to funds from operations for Q1 2015 to Q1 2014:

Funds from Operations

	Three Months Ended March 31		
(000's Cdn. $)	**2015**	2014	% Change
Net cash from operating activities	**17,109**	7,629	124
Exploration and evaluation expenses	**1,666**	644	159
Decommissioning obligations settled	**87**	234	(63)
Change in non-cash working capital	**(3,102)**	2,546	(222)
Funds from operations	**15,760**	11,053	43

Net cash from operating activities generated in Q1 2015 totaled $17.1 million versus $7.6 million generated in Q1 2014. Changes in operating margins and other cash expenditures such as general and administrative expenses, interest and other financing charges and realized risk management contracts and realized foreign exchange are largely responsible for changes in net cash from operating activities during the respective comparative periods.

The following table provides a comparison for the previous eight quarters of net cash from operating activities to funds from operations.

	2015	**2014**				2013		
(000's Cdn. $)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Net cash from operating activities	**17,109**	25,392	17,628	6,619	7,629	4,253	13,917	8,491
Exploration and evaluation expenses	**1,666**	978	1,112	1,276	644	11	301	(111)
Transaction costs	**-**	-	-	-	-	-	-	(67)
Decommissioning obligations settled	**87**	667	719	367	234	464	335	189
Change in non-cash working capital	**(3,102)**	(10,131)	(4,465)	3,348	2,546	4,285	(2,858)	1,509
Funds from operations	**15,760**	16,906	14,994	11,610	11,053	9,013	11,695	10,011

Funds from operations activities differs from the Company's calculation of net cash from operating activities due primarily to the Company's policy of expensing exploration and evaluation expenditures, transaction costs the timing of decommissioning expenditures and to the changes in non-cash working capital items.

The following table compares funds from operations by country and funds from operations per Boe by country for Q1 2015 to Q1 2014. These numbers are referred to throughout the MD&A:

Funds From Operations By Country

	Three Months Ended March 31		
(000's Cdn. $)	**2015**	2014	% Change
Canada	**13,707**	6,137	123
US	**2,053**	4,917	(58)
Funds from operations	**15,760**	11,053	43

Funds From Operations Per Boe

	Three Months Ended March 31		
($Cdn.)	**2015**	2014	% Change
Canada	**59.16**	24.87	138
US	**15.25**	39.96	(62)
Total	**43.02**	29.89	44

For Q1 2015, funds from operations totaled $15.8million or $43.02 per Boe versus $11.1 million or $29.89 per Boe for Q1 2014. The operating netback for Q1 2015 was $11.74 per Boe versus $38.71 per Boe in Q1 2014. The average price received decreased by $29.50 per Boe. Royalties decreased by $4.92 per Boe and operating costs decreased by $4.92 per Boe. The funds from operations netback in Q1 2015 included a realized gain on crude risk management contracts of $13.1 million or $35.84 per Boe versus a loss of $1.5 million or $4.18 per Boe in Q1 2014.

The following tables provide a comparison for the previous eight quarters of production, funds from operations by country, funds from operations before and after gains or losses on risk management contracts and funds from operations per Boe.

Production

	2015	2014				2013		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Oil and NGL (bbls/d)	**3,129**	3,701	3,857	3,386	2,979	3,046	3,236	2,729
Natural gas (mcf/d)	**5,648**	6,247	5,943	5,435	6,776	6,012	6,523	5,868
Total Boe	**366,349**	436,245	445,996	390,583	369,746	372,410	397,702	337,311
Boe per day	**4,071**	4,742	4,848	4,292	4,108	4,048	4,323	3,707

Production by Country

	2015	2014				2013		
(Boe per day)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Canada	**2,574**	2,990	2,950	2,765	2,741	2,332	2,461	2,318
US	**1,497**	1,752	1,898	1,527	1,367	1,716	1,862	1,389
Total	**4,071**	4,742	4,848	4,292	4,108	4,048	4,323	3,707

Funds from Operations by Country

	2015	2014				2013		
(000's Cdn. $)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Canada	**13,707**	10,758	8,029	6,665	6,137	2,871	2,294	4,378
US	**2,053**	6,148	6,965	4,945	4,916	6,142	9,401	5,633
Total	**15,760**	16,906	14,994	11,610	11,053	9,013	11,695	10,011

Funds from Operations by Country per Boe

	2015	2014				2013		
(Cdn. $)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Canada	**59.16**	39.11	29.58	26.49	24.87	13.39	10.13	20.75
US	**15.25**	38.14	39.89	35.58	39.96	38.90	54.88	44.58
Total	**43.02**	38.75	33.62	29.72	29.89	24.20	29.41	29.68

Funds from Operations

	2015	2014				2013		
(000's Cdn. $)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Before risk management contracts	**2,632**	10,528	16,351	13,860	12,597	10,002	13,725	10,183
Realized risk management contracts	**13,128**	6,378	(1,357)	(2,250)	(1,544)	(989)	(2,030)	(172)
After commodity contracts	**15,760**	16,906	14,994	11,610	11,053	9,013	11,695	10,011

Funds from Operations Netback Per Boe

	2015	2014				2013		
(Cdn. $)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Before risk management contracts	**7.18**	24.13	36.66	35.49	34.07	26.89	34.51	30.19
After risk management contracts	**43.02**	38.75	33.62	29.72	29.89	24.20	29.41	29.68

The increases and decreases in the above periods for funds from operations relate primarily to successful drilling, changes to operating netbacks as a result of fluctuations in commodity prices, the timing of new low royalty rate production or higher rate freehold production, operating cost efficiencies, the disposition of high operating cost properties, changes in interest and financing charges and to the fluctuation in realized gains and losses from commodity risk management contracts. In addition, production from new high rate, high decline North Dakota Bakken production impacts production and therefore funds from operations before commodity contracts.

In the past quarter, decreased production, lower commodity prices and changes in differentials offset by a lower Canadian dollar have combined to result in recent changes to Arsenal's funds from operations.

OUTLOOK AND 2015 GUIDANCE

The price of WTI has declined from a peak of approximately $105.00 US per barrel in June 2014 to its current level of around $60.00 US per barrel. Prices for natural gas have also deteriorated. The decline in the price of crude has had a major impact on the Company's margins in both Canada and the US and on the economics of drilling certain wells. In Canada, some of this decline has been offset by a weaker Canadian dollar and a narrower differential and with the benefit of the Alberta Crown royalty reduction on new wells, the margins in Canada and the rates of return, particularly in the areas where the Company is focusing and planning to be active, are still very acceptable. In January 2015, the Company monetized all of its 2015 crude hedging contracts and applied the proceeds to reduce debt. Arsenal is proceeding cautiously and carefully with its 2015 capital expenditure program, deferring drilling until later in the year when prices seen to be improved thereby increasing margins and focusing on its Princess and Provost project areas in Alberta, areas that deliver good margins, rates of return, reserve additions and that will provide the Company with a future growth platform. US operated drilling will be deferred until prices improve but the Company will participate in wells being proposed by partners in order to preserve the Company's working interests and reserves in the area. This conservative approach and program is intended to ensure the Company meets its flow-through share commitments from its 2014 financings, protects the Company's balance sheet and delivers a platform for future growth as margins improve.

Guidance

Arsenal's capital expenditures are now forecasted at approximately $23.5 million for 2015, of which approximately $7.3 million (down from $9.0 million) will be spent in the US and approximately $16.2 million (down from $22.5 million) will be spent in Canada. Capital expenditures are down due to changes in project scope and to reduced service costs for seismic, drilling, completions and tie's. In the US, Arsenal is participating in the drilling of 6 gross (0.89 net) Bakken and Three Forks wells at Lindahl, North Dakota. In Canada, expenditures are expected to be incurred on the completion of wells drilled in 2014 and to drill and complete 6 gross (6 net) additional wells at Princess, Alberta and one gross (one net) well at Provost, Alberta, on land and seismic, on recompletions, on capitalized general and administrative expenditures and on miscellaneous other initiatives.

Arsenal issued initial 2015 guidance in January 2015 and due to further weakening of crude prices revised its guidance in February 2015. Production in 2015 is expected to remain approximately the same and to average approximately 4,100 boe/d. Capital expenditures have been high graded and reduced and are now estimated at approximately $23.5 million, down from $31.5 million while funds from operations is expected to total approximately $33.0 million up slightly from $31.1, based on the improvement in strip prices (WTI to average approximately $56.90 US per barrel up from $55.25 US per barrel for 2015). Due to reduced capital expenditures, 2015 year end debt is expected to be approximately $55.0 million – down from approximately $68.0 million. Due to the major portion of the drilling program being deferred to the latter part of 2015, exit production is expected to be approximately 4,500 boe/d down by approximately 100 boe/d.

Production and Revenue

Production for Q1 2015 averaged 4,071 Boe per day, a 14% decrease from 4,742 Boe per day in Q4 2014 and a 1% decrease from 4,108 Boe per day in Q1 2014. Average production was down from Q4 2014 due to production declines in North Dakota and lower production from Princess the result of production curtailments due to facility constraints. The declines and lower Princess production were partially offset with the successful completion and production from one new light oil well at Evi.

Production of heavy oil declined during the current quarter when compared to Q4 2014 and Q1 2014 due to natural production declines.

Production of Canadian medium oil decreased 15% in the current quarter from Q4 2014 and increased 4% from Q1 2014. Average production was down from Q4 2014 due to lower production from Princess the result of production curtailments due to facility constraints. The declines and lower Princess production were partially offset with the successful completion of one new oil well at Evi.

It is expected that as the Company continues to drill and be successful at Princess, Alberta, the percentage of production from Canada will increase.

Production of US light oil decreased 16% in the current quarter from Q4 2014 and increased 7% from Q1 2014. Average production was down from Q4 2014 due to declines in North Dakota.

Production of natural gas decreased 10% in the current quarter from Q4 2014 and declined 17% from Q1 2014. Increases and decreases in natural gas production relate to production and subsequent decline of solution gas and to curtailment of production due to work performed on pipelines and plants.

By Commodity

	Three Months Ended March 31		
	2015	2014	% Change
Heavy oil	**1%**	1%	-
Medium oil and NGL's	**42%**	40%	5
Light oil and NGLs	**34%**	32%	8
Natural gas	**23%**	27%	(16)

Production Profile

By Country

	Three Months Ended March 31		
	2015	2014	% Change
Canada	**63%**	67%	(5)
US	**37%**	33%	10

The Company produces primarily in the provinces of British Columbia and Alberta in Canada accounting for 63% of total Q1 2015 production and in the state of North Dakota in the US that accounts for 37% of total Q1 2015 production. For Q1 2014, 67% of total production originated in Canada and 33% from the US.

The percentage of production in Canada versus in the US will change as a result of drilling success in Canada at Princess and the timing of any new production from Bakken and Three Forks wells in North Dakota. New US drilling tends to offset production declines resulting in relatively level US production period over comparative period. In this current lower priced commodity environment, the Company expects to focus more of its capital expenditure budget in Canada at Princess, Alberta due to ability to attain better margins.

Production by Area

	Three Months Ended March 31				
	2015		2014		
AREA	**Boe/d**	**% of Total**	Boe/d	% of Total	**Change**
Canada					
Galahad (light oil)	**93**	**2**	**96**	2	**(3)**
Princess (medium oil and gas)	**923**	**23**	**1,052**	26	**(12)**
Chauvin (medium oil and gas)	**258**	**6**	**261**	6	**(1)**
Provost (medium oil and gas)	**344**	**9**	**424**	10	**(19)**
Consort (medium oil and gas)	**59**	**1**	**69**	2	**(14)**
Evi (light oil)	**212**	**5**	**138**	4	**54**
Desan (gas)	**568**	**14**	**567**	14	**0**
Others	**117**	**3**	**134**	3	**(13)**
Total Canada	**2,574**	**63**	2,741	67	**(6)**
US					
Stanley (light oil)	**1,156**	**28**	**1,097**	27	**5**
Lindahl (light oil)	**281**	**7**	**203**	5	**38**
Rennie Lake/Black Slough (light oil)	**47**	**1**	**47**	1	**-**
Lake Darling (light oil)	**13**	**1**	**20**	-	**(35)**
Total US	**1,497**	**37**	1,367	33	**-**
Total	**4,071**	**100**	4,108	100	**(1)**

In Canada, the Princess area has declined as a result of production curtailments due to facility constraints, while the Provost and Consort areas have exhibited production declines as expected. The Evi area has increased due to the successful completion of one new light oil well.

In the US, production was added during 2014 from drilling Bakken wells at Stanley and from Three Forks and Bakken wells at Lindahl. This new production has offset natural declines. These wells exhibit high initial rate production with steep declines during the first couple of years. It is expected that production in these areas will remain relatively constant over time with the drilling and completion of wells at both Stanley and Lindahl offsetting yearly declines.

Prices

Prices - Before Commodity Contracts

	Three Months Ended March 31		
($Cdn.)	**2015**	2014	% Change
Canada			
Heavy oil per barrel	**42.20**	71.70	(41)
Medium oil and NGL's per barrel	**41.16**	86.09	(52)
Natural gas per mcf	**2.22**	5.35	(59)
Total per Boe	**32.13**	64.97	(51)
US			
Heavy oil per barrel	**-**	-	-
Light oil and NGL's per barrel	**49.31**	96.60	(49)
Natural gas per mcf	**4.38**	7.84	(44)
Total per Boe	**47.69**	94.09	(49)
Total			
Heavy oil per barrel	**42.20**	71.70	(41)
Oil and NGL's per barrel	**44.83**	90.74	(51)
Natural gas per mcf	**2.46**	5.51	(55)
Total per Boe	**37.85**	74.66	(49)

Reference Prices

	Three Months Ended March 31		
	2015	2014	% Change
WTI Cushing, Oklahoma ($U.S./bbl)	**48.63**	98.68	(51)
Canadian Light Sweet ($Cdn./bbl)	**53.23**	99.76	(47)
Hardisty Heavy 12 API ($Cdn./bbl)	**38.71**	78.31	(51)
Hardisty Bow River 24.9 API ($Cdn./bbl)	**42.24**	84.01	(50)
AECO (30 day spot) ($Cdn./MMBtu)	**2.75**	5.62	(51)
Henry Hub NYMEX Close ($U.S./MMBtu)	**2.81**	4.73	(41)
Foreign exchange ($Cdn./$U.S.)	**1.24**	1.10	13

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 over the comparative periods.

In Canada, the price the Company received for its medium oil and NGL decreased 52% in the current quarter versus Q1 2014. This decrease is in line with the Company’s crude quality and market reference price changes. Hardisty Bow River stream (24.9 API), that is close to the Company’s medium quality crude in Canada, decreased 50% in Q1 2015 over Q1 2014. The price received for natural gas decreased 59% in Canada and decreased 44% in the US in Q1 2015 versus Q1 2014. The price received for natural gas in Canada generally tracks changes to the AECO price which was down 51% from Q1 2014 and in the US, the Henry Hub price was down 41% from Q1 2014.

In the US, the price received for light oil decreased 49%. This corresponds to a 51% decrease in the price of WTI quarter over the comparative quarter.

The Company received an average price per Boe during Q1 2015 of $37.85 per Boe, a decrease of 49% from $74.66 per Boe received in Q1 2014. This decrease is attributed to the 51% decline, during the quarter, in the price of WTI and a decrease in the price of natural gas in both Canada and the US.

Revenues

	Three Months Ended March 31		
(000's Cdn. $)	**2015**	2014	% Change
Canada			
Heavy oil	**150**	299	(50)
Medium oil and NGL's	**6,291**	12,667	(50)
Natural gas	**1,002**	3,065	(67)
Total	**7,443**	16,031	(54)
US			
Light oil and NGL's	**6,175**	11,283	(45)
Natural gas	**248**	293	(15)
Total	**6,423**	11,576	(45)
Total			
Heavy oil	**150**	299	(50)
Oil and NGL's	**12,465**	23,950	(48)
Natural gas	**1,250**	3,357	(63)
Oil and natural gas revenues	**13,866**	27,606	(50)
Gain (loss) on realized crude commodity contracts	**13,154**	(1,527)	961
Oil and gas revenue after realized crude commodity contracts	**27,020**	26,079	4
Revenue per boe before realized crude commodity contracts	**37.85**	74.66	(49)
revenue per boe after realized crude commodity contracts	**73.75**	70.53	5

Oil and natural gas revenues of $13.9 million for Q1 2015 decreased 50% over Q1 2014 due to a 49% decrease in the average price received per Boe during the current quarter versus Q1 2014.

Oil and natural gas revenues from Canadian production totaled $7.4 million for the current quarter versus $16.0 million in Q1 2014. Production in Canada decreased 6% in the current quarter due primarily to lower production from the Princess area while the average price received per Boe in Canada decreased 51% due to declines in the price of both crude and natural gas.

Oil and natural gas revenues generated from production in the US in Q1 2015 decreased 45% to $6.4 million from $11.6 million for Q1 2014. A 7% increase in light oil production from US drilling did not offset a 49% decline in the average Boe price received in the US.

Financial Instrument Contracts

Financial instrument or risk management 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.

During the quarter ended March 31, 2015, the Company recorded a net gain of $932,331 on its financial instrument (commodity price and interest rate) contracts, of which $13.1 million was realized in Q1 2015 primarily on the monetization of its December 31, 2104 crude commodity contracts.

Subsequent to monetizing the Company's crude commodity contracts, the Company entered into two swap contracts for crude as follows:

($Cdn. unless otherwise noted)				
Commodity Sold	Volume Sold	Remaining Term	Pricing	Fair Value
Oil	500 bbl per day	October 1, 2015 - December 31, 2015	$60.80 US per bbl	265
Oil	300 bbl per day	January 1, 2016 - March 31, 2016	$57.90 US per bbl	35
				300

At March 31, 2015, the Company recorded a current risk management asset relating to its crude contracts totaling $300,487. The asset has been calculated based on a March 31, 2015 WTI Canadian dollar strip price for Q4 2015 of approximately $69.88 Canadian ($55.02 US) per barrel and for Q1 2016 of approximately $71.90 Canadian ($56.60 US per barrel).

Any future asset or liability recorded changes with changes to the price of West Texas Intermediate and with changes to the Canadian/US dollar exchange rate.

In Q4 2014, in order to mitigate the impact of future fluctuations in interest rates, the Company entered into a swap contract fixing the base interest rate on $30 million of banker's acceptance with an expiry date of February 13, 2018.

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

Subject of Contract	Remaining Term	Notional Quantity	Reference	Strike Price	Option Traded	Fair Value
30 day BA rate	April 1, 2015 - February 13, 2018	$ 30,000,000	CAD - BA - CDOR	1.80%	Swap	(746)

The rates above are, as provided for in 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 two most recent quarter ends annualized.

As at March 31, 2015, the Company has an interest rate risk management liability recorded totaling $746,110.

The future asset or liability recorded changes with changes to interest rates.

Risk Management Contracts

	Three Months Ended March 31		
(000's Cdn. $)	**2015**	2014	% Change
Realized gain (loss)			
Commodity	**13,154**	(1,528)	961
Interest rate	**(26)**	(16)	(63)
Total	**13,128**	(1,544)	950
Unrealized gain (loss)			
Commodity	**(11,646)**	(1,452)	(702)
Interest rate	**(550)**	11	5,100
Total	**(12,196)**	(1,441)	(746)
Total gain (loss)			
Commodity	**1,508**	(1,528)	199
Interest rate	**(576)**	(5)	(11,423)
Total risk management contracts	**932**	(1,533)	161
Per boe realized risk management contracts	**35.84**	(4.18)	958
Per boe unrealized risk management contracts	**(33.29)**	(3.90)	(754)
	2.54	(4.15)	161

Royalties

	Three Months Ended March 31		
(000's Cdn. $)	**2015**	2014	% Change
Canada			
Heavy oil	**13**	23	(43)
Medium oil and NGL's	**1,775**	1,867	(5)
Natural gas	**11**	322	(96)
Total	**1,799**	2,213	(19)
US			
Light oil and NGL's	**1,722**	3,147	(45)
Natural gas	**47**	62	(24)
Total	**1,769**	3,209	(45)
Total			
Heavy oil	**13**	23	(43)
Oil and NGL's	**3,497**	5,014	(30)
Natural gas	**58**	383	(85)
Royalties	**3,569**	5,421	(34)
Royalties per Boe	**9.74**	14.66	(34)

Percentage By Product

	Three Months Ended March 31		
	2015	2014	% Change
Heavy oil	**9**	8	13
Oil and NGL's	**28**	21	34
Natural gas	**5**	11	(59)
Total	**26**	20	31

Percentage By Country

	Three Months Ended March 31		
	2015	2014	% Change
Canada	**24**	14	75
US	**28**	28	-
Total	**26**	20	31

The Company's overall royalty rate for Q1 2015 averaged 26% compared to 20% for Q1 2014.

In Q1 2015, oil and NGL rates increased in Canada due to the assessment of freehold mineral taxes on new freehold wells at Princess.

During the current quarter, the royalty rate decreased for natural gas as these royalty rates are somewhat price sensitive and due to lower natural gas production in Q1 2015.

Going forward, the corporate royalty rate is expected to average in the 22% - 23% range. The rate fluctuates due to the timing of drilling low royalty rate wells in Canada, to production increases from higher royalty rate US wells and to some extent, commodity prices and production rates. Increases or decreases in the dollar value of royalties are somewhat commodity price related with higher commodity prices resulting in a higher royalty payable and lower commodity prices resulting in a lower royalty payable.

Operating and Transportation Expenses

	Three Months Ended March 31		
(000's Cdn. $)	**2015**	2014	**% Change**
Canada			
Heavy oil	**161**	190	(15)
Medium oil and NGL's	**3,529**	5,450	(35)
Natural gas	**1,136**	1,210	(6)
Total	**4,826**	6,850	(30)
US			
Light oil and NGL's	**1,136**	1,004	13
Natural gas	**34**	20	74
Total	**1,170**	1,024	14
Total			
Heavy oil	**161**	190	(15)
Oil and NGL's	**4,665**	6,454	(28)
Natural gas	**1,171**	1,229	(5)
Operating and transportation	**5,997**	7,874	(24)
Operating and transportation per Boe	**16.37**	21.29	(23)

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.

On an absolute dollar basis, operating costs decreased in Q1 2015 by $1.9 million or 24% from Q1 2014.

On a Boe basis, operating costs decreased in Q1 2015 to $16.37 per boe from $21.29 per boe in Q1 2014.

Operating costs decreased due to shut-in high operating cost wells and lower workover expenses in Q1 2015 compared to Q1 2014.

Operating Netback per Boe

	Three Months Ended March 31			Three Months Ended March 31			
		2015			2014		**Corporate**
($Cdn.)	**Canada**	**US**	**Corporate**	Canada	US	Corporate	**% Change**
Heavy oil							
Revenue	**42.20**	**-**	**42.20**	71.70	-	71.70	**(41)**
Royalty	**(3.75)**	**-**	**(3.75)**	(5.63)	-	(5.63)	**(33)**
Operating and transportation	**(45.20)**	**-**	**(45.20)**	(45.54)	-	(45.54)	**(1)**
Operating netback per barrel	**(6.75)**	**-**	**(6.75)**	20.53	-	20.53	**(133)**
Medium and light oil and NGL's							
Revenue	**41.16**	**49.31**	**44.83**	86.09	96.60	90.74	**(51)**
Royalty	**(11.61)**	**(13.75)**	**(12.58)**	(12.69)	(26.94)	(19.00)	**(34)**
Operating and transportation	**(23.09)**	**(9.07)**	**(16.78)**	(37.04)	(8.60)	(24.45)	**(31)**
Operating netback per barrel	**6.46**	**26.48**	**15.48**	36.36	61.06	47.29	**(67)**
Natural gas							
Revenue	**2.22**	**4.38**	**2.46**	5.35	7.84	5.51	**(55)**
Royalty	**(0.02)**	**(0.83)**	**(0.11)**	(0.56)	(1.65)	(0.63)	**(82)**
Operating and transportation	**(2.52)**	**(0.61)**	**(2.30)**	(2.11)	(0.53)	(2.02)	**14**
Operating netback per mcf	**(0.32)**	**2.94**	**0.04**	2.68	5.66	2.86	**(99)**
Boe							
Revenue	**32.13**	**47.69**	**37.85**	64.97	94.09	74.66	**(49)**
Royalty	**(7.77)**	**(13.14)**	**(9.74)**	(8.97)	(26.08)	(14.66)	**(34)**
Operating and transportation	**(20.83)**	**(8.69)**	**(16.37)**	(27.76)	(8.32)	(21.29)	**(23)**
Operating netback per Boe	**3.53**	**25.86**	**11.74**	28.24	59.69	38.71	**(70)**

Canadian Netback

The Q1 2015 operating netback from Canadian heavy oil production decreased $27.28 per barrel or 133% from Q1 2014 due to lower prices and lower volumes in Q1 2015 compared to Q1 2014.

The Q1 2015 operating netback from Canadian medium oil and NGL decreased $29.90 per barrel or 82% from Q1 2014. Lower average crude prices in Q1 2015 were offset by lower operating expenses. The average price received decreased by 52% to 41.16 per Boe while operating expenses decreased 38% to $23.09 per barrel.

The Q1 2015 netback from Canadian natural gas decreased $3.00 per mcf or 112% from Q1 2014 due to lower prices and lower volumes in Q1 2015 compared to Q1 2014.

US Netback

The Q1 2015 netback from the US light oil and NGL decreased $34.58 per barrel or 57% from Q1 2014 due to lower crude pricing in North Dakota.

The Q1 2015 netback from the US natural gas decreased $2.73 per mcf or 48% from Q1 2014 due to lower prices.

Corporate Netback

Arsenal’s Q1 2015 average price decreased $36.81 per Boe or 49% to $37.85 per Boe from $74.66 per Boe received in Q1 2014. Royalties in Q1 2015 decreased on a Boe basis $4.92 commensurate with the lower prices in Q1 2015 averaging $9.74 per Boe versus $14.66 per Boe in Q1 2014. Operating costs in Q1 2015 declined $4.93 per Boe to averaged $16.37 per Boe versus $21.29 per Boe in Q1 2014. The 23% decrease in operating costs in Q1 2015 from Q1 2014 resulted from shutting-in some high operating cost wells and lower workover expenses in Q1 2015 compared to Q1 2014. As a result, the corporate netback in Q1 2015 declined $26.97 per Boe to average $11.74 per Boe versus $38.71 per Boe in Q1 2014

General and Administrative Expenses

(000's Cdn. $)	Three Months Ended December 31		
	2015	2014	% Change
Gross expenditures	**1,762**	1,648	7
Overhead recovery	**(486)**	(499)	(3)
Capitalized overhead	**(175)**	(162)	8
Net general and administrative expense	**1,101**	987	12
Net general and administrative per boe	**3.01**	2.67	13

For Q1 2015, gross general and administrative expenditures were higher than in Q1 2014 by $113,719. On a net basis, general and administrative expenses increased in Q1 2015 over Q1 2014 by $114,502. Both gross expenditures and net expenses increased primarily due to costs related to severance paid on a staff reduction. These increased costs were offset by a lower 2015 bonus provision and by initiatives to generally reduce expenditures in the current low crude price environment. On a Boe basis, general and administrative expenditures for the current quarter increased to $3.01 per Boe from $2.67 per Boe in Q1 2014.

Exploration and Evaluation Expenses

(000's Cdn. $)	Three Months Ended March 31		
	2015	2014	% Change
Exploration and evaluation expenses	**1,666**	644	159
Per Boe	**4.55**	1.74	161

Arsenal expenses all pre-license costs, all seismic expenditures and all exploratory dry hole costs. Recoveries of these expenses are credited to exploration and evaluation expenses.

In Q1 2015, the Company incurred certain seismic expenditures in Cessford and Princess, Alberta related to its prospect development program. In Q1 2014, the seismic expenditures were incurred primarily in Princess, Alberta.

Property, Plant and Equipment Impairment

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 fair value is estimated based on the greater of its fair value in use or its fair value less costs to sell.

An impairment loss is recognized if the carrying amount of an asset or its Cash Generating Unit ("CGU") exceeds its value in use or fair value less costs to sell. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGU's reduce the carrying amounts of the other assets in the unit (group of units) on a pro rata basis.

On March 31, 2015 and March 31, 2014, no indicators of impairment existed.

The fair value amount of the Company's CGU's are sensitive to changes in commodity prices. Impairment charges could be recorded in future periods should commodity prices decline. Alternatively, an improvement of commodity prices could reverse impairment charges recorded to date, less applicable depletion and depreciation charges.

Interest and Other Financing Expenses

	Three Months Ended March 31		
(000's Cdn. $)	**2015**	2014	% Change
Interest and other financing charges	**536**	663	(19)
Per Boe	**1.46**	1.79	(18)

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

Interest and other financing fees decreased 19% in Q1 2015 from Q1 2014 due primarily to lower interest paid on the Company's borrowings. For Q1 2015, the average daily borrowing balance was $52.4 million versus $71.2 million for Q1 2014.

Interest rates on the facility range from Canadian or US prime plus 1.00% to 2.50% on prime based loans and from the base rate plus 2.00% to 3.50% on bankers' acceptances and on Libor based loans based on the Company's debt to cash flow ratio as determined under the provisions of the agreement.

Depletion and Depreciation

	Three Months Ended March 31		
(000's Cdn. $)	**2015**	2014	% Change
Depletion and depreciation	**7,442**	6,762	10
Per boe	**20.31**	18.29	11

On an absolute dollar basis, depletion and depreciation in Q1 2015 increased 10% from Q1 2014. This increase was attributed primarily to US operations as Canadian depletion decreased. On a Boe basis, depletion and depreciation increased 11% to $20.31 per Boe in Q1 2015 versus $18.29 per Boe in Q1 2014. The increase is due to a stronger US dollar thereby increasing historical and future development costs in Canadian dollar terms, to a year-end reduction in US reserves and to an increase in the Canadian and US decommissioning provision due to increased cost estimates and to a decrease in the discount rate applied to the decommissioning liabilities in both Canada and the US.

In Canada, the depletion and depreciation rate decreased from $17.23 per Boe in Q1 2014 to $16.23 per Boe in Q1 2015 based on increased reserves at Princess, Alberta and on positive performance adjustments in some other areas. The decrease was partially offset by an increase in the cost estimate to abandon and decommission wells and to a decrease in the discount rate applied to the decommissioning liabilities in Canada.

In the US, the depreciation and depletion rate increased from $20.40 per Boe in Q1 2014 to $27.34 per Boe in Q1 2015 due, to a year-end reduction in US reserves, to a stronger US dollar (up 9% from December 31, 2014), to an increase in the cost estimate to abandon and decommission wells and to a decrease in the discount rate applied to the decommissioning liabilities in the US.

Share-based Compensation

	Three Months Ended March 31		
(000's Cdn. $)	**2015**	2014	% Change
Share-based compensation expense (recovery)	**(988)**	**920**	(207)
Per boe	**(2.70)**	**2.49**	(208)

The Company has determined that, in certain circumstances, it will cash settle stock options and a portion of the Company's share awards outstanding. The Company has recorded an incentive (share-based) compensation liability of $396,837 related to these cash settled instruments.

As a result of changes to the Company's share price, the Company is required to revalue or re-measure the fair market value of the Company's incentive compensation liability at the end of each reporting period. The adjustment (up or down) to the liability is recorded in the statement of income. The change in fair value of the Company's shares resulted in a recovery of previously expensed share-based compensation in the current quarter of $988,460.

At March 31, 2015, the Company had 930,837 options outstanding at a weighted average strike price of $6.51 per share. Of these outstanding options, 723,551 are exercisable at a weighted average strike price of $7.18

In May 2014, the Company implemented a share award incentive plan and discontinued any further grants of options under the option plan. All current outstanding options will expire at the end of their respective term.

Under the share award incentive plan, the Company may issue restricted awards and/or performance awards. Restricted awards entitle the participant to one common share of the Company for each restricted award issued. Performance awards entitle the participant to common shares of the Company based on a payout multiple based on pre-determined corporate performance measures of from 0 times to 2 times the number of performance awards issued.

In June 2014, the Company issued 126,600 restricted awards and 114,600 performance awards to directors, officers and employees. These awards vest as to one-third on each of the first second and third anniversary dates of the grant. The Company has determined that the payment will be partially in common shares and partially in cash has accounted for these awards as both equity settled and has estimated a performance payout of 1 on the performance awards and as liability settled.

No share-based compensation has been capitalized during Q1 2015 or Q1 2014.

Accretion

	Three Months Ended March 31		
(000's Cdn. $)	**2015**	**2014**	% Change
Accretion	**290**	306	(5)
Per boe	**0.79**	0.83	(4)

Accretion is the increase or decrease, in the reporting period, in the present value of the Company's decommissioning liabilities. Accretion also includes additional expenditures incurred to decommission well sites and facilities over and above the estimate contained in the decommissioning liability provision.

Accretion decreased in Q1 2015 by 5% from Q1 2014 due to a lower discount rate used to discount the Company's future liabilities.

Provision for Income Taxes

	Three Months Ended March 31		
(000's Cdn. $)	**2015**	**2014**	% Change
Current tax expense	**53**	171	(69)
Deferred tax expense	**(1,182)**	987	(220)
Total	**(1,129)**	1,158	(197)
Per Boe - current	**0.15**	0.46	(68)
Per Boe - deferred	**(3.23)**	2.67	(221)
Per boe - Total	**(3.08)**	3.13	(198)

For the three months ended March 31, 2015, the Company has recorded income tax recovery of $1.1 million. In Canada, income before income tax was $30,480, while the US lost $1.6 million before income tax.

In Canada, the Company has not recorded any recovery of income tax as the Company has accumulated losses from Canadian operations and has Canadian tax pools in excess of $105 million at March 31, 2015. The Company has recognized a portion of the premium related to the issuance of flow-through shares in 2014. The Company incurred flow-through expenditures in Q1 2015 of approximately $3.9 million recognizing $488,773 of the recorded premium. The Company has a long term liability (flow-through share issue premium) of $1.1 million related to approximately $8.0 million of remaining qualifying expenditures required to be incurred by December 31, 2015.

In the US, the Company has recorded income tax recovery of $639,821 of which $693,106 represents a recovery of income tax and $53,285 represents current tax payable relating to Alternate Minimum Tax ("AMT" see below).

The AMT attempts to ensure that corporations that benefit from certain deductions (such as intangible drilling costs, accelerated depreciation and non-capital losses) pay at least a minimum tax. In calculating the AMT, these deductions are reduced from the amounts allowed under the calculation of income tax. The tax credit for AMT payments can be used to offset future regular income taxes payable.

At March 31, 2015, the deferred tax liability recorded in the Company's Statement of Financial Position of $21.6 million relates entirely to the US operations.

Net Cash from Operating Activities, Funds from Operations and Net Income (Loss)

	Three Months Ended March 31		
(000's Cdn. $ except per share amounts)	**2015**	2014	Change
Net cash from operating activities	**17,109**	7,629	124
Funds from operations	**15,760**	11,053	43
Per share			
Basic	**0.88**	0.69	28
Diluted	**0.87**	0.69	27
Net income (loss)	**(466)**	1,028	(145)
Per share			
Basic	**(0.03)**	**0.06**	(141)
Diluted	**(0.03)**	0.06	(140)

Weighted Average Shares Outstanding

	Three Months Ended March 31		
(000's Cdn. $ except per share amounts)	**2015**	**2014**	Change
For Net (Loss) / Income Purposes			
Basic	17,884	16,090	11
Diluted	17,884	16,119	11
For Funds from Operations Purposes			
Basic	17,884	16,090	11
Diluted	18,126	16,119	12

Funds from operations (after realized commodity contract gains) for Q1 2015 totaled $15.8 million ($0.88 per share basic and $0.87 per share diluted) versus funds from operations in Q4 2014 of $16.9 million ($0.98 per share basic and $0.95 per share diluted) and $11.1 million ($0.69 per share basic and diluted) in Q1 2014.

Funds from operations in Q1 2015 decreased from Q4 2014 by $1.1 million. The monetization, in Q1 2015, of the Company's December 31, 2015 crude commodity contracts provided realized commodity contract gains of $6.8 million over the gains realized in Q4 2014 thereby partially offsetting a production decrease (down 14%) and a decrease in the average operating margin received per Boe (down 58%).

Funds from operations in Q1 2015 increased from Q1 2014 by $4.7 million. The monetization, in Q1 2015, of the Company's December 31, 2014 crude commodity contracts generated a realized commodity contracts gain of $13.1 million versus realized commodity contract losses of $1.5 million thereby offsetting a production decrease (down 1%) and a decrease in the operating margin received per Boe (down 70%).

On a Boe basis, funds from operations for Q1 2015 increased to $43.02 per Boe versus $38.75 for Q4 2014 and $29.89 for Q1 2014. Lower production and lower prices were offset by the funds realized during the current quarter on the monetization of the Company's 2015 crude commodity risk management contracts. Realized gains on risk management contracts added $13.1 million or $35.84 per Boe in the current quarter versus a gain of $6.4 million or $14.62 per Boe in Q4 2014 and a loss of $1.5 million or $4.18 in Q1 2014.

The Company recorded a net loss in Q1 2015 of $466,316 or $0.03 per share basic and diluted versus income of $1.0 million or $0.06 per share basic and diluted in Q1 2014. While funds realized on the monetization of the crude commodity contracts generated income of $932,331, the operating margin that declined 70% or $26.97 per Boe, $1.7 million of exploration and evaluation expenses and higher depletion and depreciation all contributed to produce the current quarter loss.

Comprehensive Income

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. The translation of the Company's US subsidiary into Canadian dollars resulted in a gain of $3.0 million. Comprehensive income therefore for the three months ended March 31, 2015 was $2.6 million versus comprehensive income of $2.0 million for the three months ended March 31, 2014.

Net Income (Loss) per Boe

	Three Months Ended March 31	
($Cdn.)	**2015**	2014
Oil and gas revenue	37.85	74.66
Royalties	(9.74)	(14.66)
Operating and transportation	(16.37)	(21.29)
Operating netback per Boe	**11.74**	38.71
Realized gain (loss) on risk management contracts	35.84	(4.18)
Realized gain on foreign exchange	0.06	0.29
General and administrative	(3.01)	(2.67)
Interest and other financing charges	(1.46)	(1.79)
Current tax expense	(0.15)	(0.46)
Funds from operations netback per Boe	**43.02**	29.89
Unrealized gain (loss) on risk management contracts	(33.29)	(3.90)
Unrealized gain on foreign exchange	8.73	2.80
Depletion and depreciation	(20.31)	(18.29)
Accretion	(0.79)	(0.83)
Exploration and evaluation - directly expensed	(4.55)	(1.74)
Share-based compensation	2.70	(2.49)
Deferred income tax	3.23	(2.67)
Net income (loss) per Boe	**(1.28)**	2.78

On a net income (loss) per Boe basis, the fluctuation in commodity prices not only affects the average Boe price received but can (as show in the above table) significantly create large swings in the recording of changes in the unrealized portion of the Company's risk management contract positions. In addition, changes in the (Canadian/US) foreign exchange rates and impairment provisions for exploration and evaluation assets and property plant and equipment assets can result in large fluctuations in net income (loss) per Boe.

Summary of Quarterly Results

	2015	2014				2013		
(000's Cdn. $)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Production (Boe)								
Total	366,349	435,344	445,997	390,583	369,746	372,410	397,702	337,311
Per day	4,071	4,732	4,848	4,292	4,108	4,048	4,323	3,707
Oil and gas revenue	13,866	25,210	33,322	30,902	27,606	24,112	30,177	22,405
Funds from operations	15,760	16,906	14,994	11,610	11,053	9,013	11,695	10,011
Per share - basic ($)	0.88	0.98	0.89	0.72	0.69	0.56	0.73	0.63
- diluted ($)	0.87	0.95	0.88	0.71	0.69	0.56	0.72	0.63
Net income (loss)	(466)	15,367	9,622	(376)	1,028	(396)	(627)	2,957
Per share - basic ($)	(0.03)	0.89	0.89	(0.02)	0.06	(0.02)	(0.04)	0.19
- diluted ($)	(0.03)	0.81	0.81	(0.02)	0.06	(0.02)	(0.04)	0.19
Total assets	230,571	236,424	223,262	211,996	202,146	191,922	191,000	189,690
Total debt (1)	57,229	65,198	81,230	84,417	74,294	70,422	69,147	67,078
Shares outstanding	17,897	17,877	16,974	16,074	16,090	16,080	16,070	16,070

(1) Includes bank debt and working capital but excludes risk management contracts whether current or long term assets or liabilities.

Arsenal's quarterly results have fluctuated significantly in the past eight quarters due to a variety of factors that include commodity price and production swings, the widening differentials, the timing of drilling and completions particularly in the

US and in Alberta at Evi, the rationalization of properties and operating costs and in the past two quarters, the shutting in of some natural gas production due to low prices. Arsenal has been and expects to continue to rationalize its asset base focusing on properties with a long reserve life and high netbacks where the Company has a strategic, technical or financial advantage. Quarterly results therefore will continue to fluctuate somewhat and will depend somewhat 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, the Company expects its established production base to increase steadily which should lead to more comparative and stable results going forward.

Segmented Information

Three month Ended March 31, 2015 (000's Cdn. $)	Canada	U.S	Total
Production (Boe/d)	2,574	1,496	**4,071**
Oil and gas revenue	7,443	6,423	**13,866**
Operating income	817	3,483	**4,300**
Funds from operations	13,707	2,053	**15,760**
Income (loss) before income taxes	30	(1,625)	**(1,595)**
Net income (loss) for the year	519	(985)	**(466)**
Exploration and evaluation assets (as at March 31, 2014)	3,639	-	**3,639**
Property, plant and equipment (as at March 31, 2014)	109,794	105,089	**214,883**
Property, plant and equipment expenditures	3,770	2,901	**6,671**
Exploration and evaluation expenditures	-	-	**-**
Exploration and evaluation expenses	1,666	-	**1,666**
Property dispositions	-	-	**-**
Property acquisitions	-	-	**-**

For Three Months Ended March 31, 2014 (000's Cdn. $)	Canada	U.S	Total
Production (Boe/d)	2,741	1,367	**4,108**
Oil and gas revenue	16,031	11,575	**27,606**
Operating income	6,968	7,343	**14,311**
Funds from operations	6,137	4,916	**11,053**
Income (loss) before income taxes	398	1,788	**2,186**
Net income (loss) for the year	436	592	**1,028**
Exploration and evaluation assets (as at March 31, 2014)	9,919	-	**9,919**
Property, plant and equipment (as at March 31, 2014)	95,672	79,233	**174,905**
Property, plant and equipment expenditures	3,696	8,369	**12,065**
Exploration and evaluation expenditures	276		**276**
Exploration and evaluation expenses	644	-	**644**
Property dispositions	-	-	**-**
Property acquisitions	152		**152**

[1] Operating income is defined as revenue from oil and natural gas sales less royalties and operating and transportation expenses.

As the Company focuses its capital program on drilling at Princess, Alberta, it is expected that the Canadian operations will generate a more significant portion of the Company’s production, revenues, and profits.

Liquidity and Capital Resources

Capital Management

The Company considers its capital structure to include working capital, the credit facility and shareholders' equity. The Company manages its capital base primarily on its net debt to annualized funds from operations ratio and its net debt to equity ratio The Company continually monitors, through its annual budgeting and quarterly forecasting process, the risk reward profile of its exploration and development projects, its production profile and the economic indicators in the market including commodity prices, interest rates and foreign exchange rates. It then determines increases or decreases to its capital budget and what, if any, additional initiatives may need to be implemented.

Net debt includes bank borrowings, plus or minus working capital and excludes long term decommissioning obligations and risk management contracts (whether an asset or an obligation). Annualized funds from operations is calculated as net cash from operating activities, before changes in non-cash working capital, decommissioning obligations settled, exploration and evaluation expenses and transaction costs from the Company's most recent quarter multiplied by four. The annualized funds from operations is further adjusted, if required, for large one-time items included in the recent quarter.

The Company's net debt to annualized funds from operations ratio at March 31, 2015 is 0.91 : 1.

The Company's net debt to equity ratio is 0.62: 1.

The Company expects to focus its future capital expenditure program on drilling exploratory wells in Alberta at Princess and in the US at Lindahl, North Dakota. The program is flexible and is designed to ensure that the Company meets all of its 2014 flow-through commitments, to build development drilling for when prices and margins improve and to retain our interest in our US drilling inventory.

Net Debt and Debt to Annualized Funds from Operations

(000's Cdn. $)	March 31, 2015
Bank loan	53,551
Working capital deficiency (1)	3,678
Total debt	57,229
Annualized funds from operations	63,041
Net debt to annualized funds flow ratio	**0.91**

(1) Working capital is calculated as current assets minus current liabilities adjusted for the value of risk management contracts whether a current asset or a current liability. The Company maintains sufficient unused bank credit facility to ensure any working capital deficiency can be funded.

Net Debt Reconciliation

(000's Cdn. $)	**Three Months Ended March 31**
Net debt December 31, 2014	**65,198**
Funds from operations	**(15,760)**
Additions to property, plant and equipment	**6,671**
Exploration and evaluation expenses	**1,666**
Dividends	**465**
Decommissioning liabilities settled	**87**
Foreign exchange gain on US cash held	**(180)**
Change in working capital and other items	**(918)**
Net debt March 31, 2015	**57,229**

Debt to Equity Ratio

(000's Cdn. $)	March 31, 2015
Shareholders' Equity	92,971
Debt to equity	**0.62**

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

The Company has not adjusted its approach to capital management during Q1.

Credit Facility

The Company’s $90.0 million credit facility consists of a revolving line of credit of $80.0 million and an operating line of credit of $10.0 million (the ‘Facility”).

The available lending limits are reviewed semi-annually and are based on the bank syndicate’s interpretation of the Company’s reserves and future commodity prices. The next review by the syndicate is to be completed on or before May 31, 2015 and due to the severe decline in crude prices since the last review date, is expected to be reduced from its current level.

The Facility is subject to certain positive and negative covenants including a covenant not to dispose of assets or property having a fair aggregate value exceeding 5% of the borrowing base without an assessment of an adjustment to the borrowing base and the facility and to not make distributions (defined to include dividends and purchases under a NCIB) in excess of $5.0 million annually. In addition, the credit facility is subject to a semiannual borrowing base review based on internally generated engineering.

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

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

At March 31, 2015, the Company was in compliance with this covenant.

At March 31, 2015, debt under the Facility amounted to $53.6 million (December 31, 2014 - $60.0 million) (March 31, 2014 - $71.0 million). Net debt at March 31, 2015 was $57.2 million (December 31, 2014 - $65.2 million) (March 31, 2014 - $74.3 million).

Liquidity

Crude prices started to decline in late 2014 to where we are now at approximately WTI $56.00 US per barrel. This significant decline has had an adverse effect on the Company's operating margins and therefore on funds from operating activities and on capital available to be reinvested in 2015. In addition, the decline in prices has had a negative impact on the Company's reserve that will likely result in a decrease in the Company's borrowing base and therefore its credit facility.

In order to strengthen the Company's balance sheet, the Company monetized a portion of its crude hedge book in December 2014 and the remainder in January 2015 (these transactions reduced debt by approximately $16.1 million). In addition, the Company reduced the dividend in February 2015 to $0.03 per share from $0.07 per share, reduced employee bonuses and undertook other initiatives to reduce capital, operating and general and administrative expenditures.

With these initiatives and the Company's current production base continuing to generate positive margins and cash flow, management believes that they have positioned the Company to create value for shareholders and have aligned funds from operations with capital expenditures and dividends. The Company will exercise a disciplined approach to its payout ratio with an effort to maintain financial strength and flexibility while utilizing a prudent use of debt.

Dividends

In August 2013, the Board of Directors adopted a dividend policy, approving a quarterly dividend payment to shareholders of approximately 10% of the Company's trailing cash flow as adjusted for significant one-time cash inflows or outflows and current economic factors and expectations. The initial dividend was set at $0.06 per common share and, based on strong cash from operations, has been increased twice since August 2013. On February 9, 2015, in light of the significant decline in crude prices and the reduced cash from operations and in order to maintain balance sheet strength, the Board agreed to reduce the dividend to $0.03 per common share.

In June 2014, shareholders approved a special resolution authorizing certain amendments to the Articles of the Company to permit the payment of share dividends on common shares to shareholders electing to receive dividends in common shares of the Company**.** Shareholders wishing to participate in the Share Dividend Plan should contact their broker or intermediary or, in the case of registered shareholders, contact our transfer agent, Alliance Trust Company, or visit our website to obtain the necessary enrolment forms.

Dividend History

Year	Declaration Date	Record Date	Payment Date	Dividend Per Common Share Cdn. $	Common Shares Outstanding	Total Value Returned To Shareholders Cdn. $	Cash	Shares Issued
2013	August 7	August 15	August 30	0.060	16,069,586	964,175	964,175	-
	November 6	November 15	November 29	0.060	16,069,586	964,175	964,175	-
2014	February 11	February 21	February 28	0.060	16,090,119	965,407	965,407	-
	May 6	May 16	May 30	0.065	16,074,419	1,044,838	1,044,838	-
	August 6	August 18	August 28	0.070	16,886,485	1,182,054	966,209	21,044
	November 4	November 14	November 28	0.070	16,938,028	1,185,661	1,013,684	21,294
2015	February 9	February 17	February 27	0.030	17,877,272	536,318	465,325	19,489
	May 4	May 15	May 29	0.020	17,896,761	357,935	**To be determined**	

Share Capital

On March 27, 2014, the Company announced its intention to make a normal course issuer bid ("NCIB") that commenced April 1, 2014 and ended March 31, 2015. During 2014, a total of 40,900 common shares were purchased under the NCIB at an average price of $7.24 per share plus expenses. No shares were acquired in Q1 2015.

In June 2014, shareholders approved a special resolution authorizing special amendments to the Articles of the Company to permit the payment of share dividends on common shares. In 2014, 42,338 common shares were issued to shareholders representing a dividend value of $357,822. In Q1 2015, 19,489 common shares were issued to shareholders representing a dividend value of $70,994

Common Shares

	Period Ended March 31, 2015		Year Ended December 31, 2014	
(000's)	**Shares**	**$**	Shares	$
Balance - beginning of period	**17,877**	**151,434**	16,080	137,705
Issued under private placements	-	-	1,712	16,558
Share issue costs	-	-	-	(3,715)
Issued on exercise of options	-	-	101	877
Issued on share dividend	**20**	**71**	42	358
Purchases under normal course issuer bid	-	-	(41)	(349)
Cancelled on expiration of amalgamation exchange provision	-	-	(17)	-
Balance - end of period	**17,897**	**151,505**	17,877	151,434

Options

(000's)	**Period Ended March 31, 2015**	Year Ended December 31, 2014
Balance - beginning of period	**1,014**	1,268
Exercised	-	(101)
Option "puts" cash settled by the Company	-	(148)
Cancelled (forfeited or expired unexerecised)	**(83)**	(5)
Balance - end of period	**931**	1,014

Share Incentive Awards

In May 2014, the Company implemented a share award incentive plan and discontinued any further grants of options under the option plan. All current outstanding options will expire at the end of their respective term.

Under the share award incentive plan, the Company may issue restricted awards and/or performance awards to participants to a maximum of 4.5% of the Company's issued and outstanding common shares. Restricted awards entitle the participant to one common share of the Company for each restricted award issued. Performance awards entitle the participant to common shares of the Company based on a payout multiple based on pre-determined corporate performance measures of from 0 times to 2 times the number of performance awards issued. All awards are adjusted to include dividends from the date of grant to the date of vesting.

The Company has the option of settling the notional value of the common shares underlying the award by payment in common shares issued from treasury or payment in cash.

	Three Months Ended March 31, 2015		**Year Ended December 31, 2014**	
(000's)	**Restricted**	**Performance**	**Restricted**	**Performance**
Balance - beginning of period	**126,600**	**114,600**	-	-
Awards isued	-	-	126,600	114,600
Balance - end of period	**126,600**	**114,600**	126,600	114,600

At March 31, 2015, the Company has 17,896,761 common shares outstanding, 930,837 options outstanding at a weighted average price of $6.51 per share and 126,600 restricted share rights and 114,600 performance share rights awarded under the share award plan outstanding.

As of the date of this MD&A, the Company has 17,896,761 common shares outstanding, 930,837 options outstanding and 126,600 restricted share rights and 114,600 performance share rights outstanding.

Capital Expenditures

Capital expenditures for Q1 2015 to property, plant and equipment totaled $6.7 million down from $11.9 million in Q1 2014. Expenditures in Q1 2015 were incurred in Canada ($3.8 million) primarily to complete wells and on facilities at Princess and on the completion of a well at Evi. Expenditures were incurred in the US, ($2.9 million) primarily to drill wells at Lindahl.

Total Company

Property, Plant and Equipment Expenditures

	Three Months Ended March 31,	
(000's Cdn. $)	**2014**	**2013**
Land	**312**	245
Drilling and completions	**3,802**	9,765
Capitalized general and administrative	**175**	162
Production equipment, facilities and tie-ins	**2,382**	1,706
Other	**566**	(221)
Total property plant and equipment additions	**7,237**	11,657
Non-cash additions	**(566)**	256
Total Property, Plant and Equipment Expenditures	**6,671**	11,913

Exploration and Evaluation Expenditures

	Three Months Ended March 31,	
(000's Cdn. $)	**2014**	**2013**
Land	**-**	210
Drilling and completions	**-**	66
Total Exploration and Evaluation Expenditures	-	276

Property Acquisitions

	Three Months Ended March 31,	
(000's Cdn. $)	**2014**	**2013**
Total Property Acquisitions	**-**	152

Exploration and Seismic Expenses

	Three Months Ended March 31,	
(000's Cdn. $)	**2014**	**2013**
Seismic expenditures	**1,666**	644
Proceeds on sale of seismic	**-**	-
Total Exploration and Seismic Expenses	**1,666**	644

CANADA

Property, Plant and Equipment Expenditures

(000's Cdn. $)	Three Months Ended March 31, 2014	2013
Land	**209**	-
Drilling and completions	**1,424**	1,754
Capitalized general and administrative	**175**	162
Production equipment, facilities and tie-ins	**1,962**	1,593
Other	**559**	(246)
Total property plant and equipment additions	**4,329**	3,263
Non-cash additions	**(559)**	281
Total Property, Plant and Equipment Expenditures	**3,770**	3,544

Exploration and Evaluation Expenditures

(000's Cdn. $)	Three Months Ended March 31, 2014	2013
Land	**-**	210
Drilling and completions	**-**	66
Total Exploration and Evaluation Expenditures	**-**	276

Property Acquisitions

(000's Cdn. $)	Three Months Ended March 31, 2014	2013
Total Property Acquisitions	**-**	152

Exploration and Seismic Expenses

(000's Cdn. $)	Three Months Ended March 31, 2014	2013
Seismic expenditures	**1,666**	**644**
Proceeds on sale of seismic	**-**	**-**
Total Exploration and Seismic Expenses	**1,666**	644

Property, Plant and Equipment Expenditures

(000's Cdn. $)	Three Months Ended March 31, 2014	2013
Land	**103**	245
Drilling and completions	**2,378**	8,011
Capitalized general and administrative	**-**	-
Production equipment, facilities and tie-ins	**420**	113
Other	**7**	25
Total property plant and equipment additions	**2,908**	8,394
Non-cash additions	**(7)**	(25)
Total Property, Plant and Equipment Expenditures	**2,901**	8,369

Decommissioning Obligations

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

(000's Cdn. $)	**Period Ended March 31, 2015**	Year Ended December 31, 2014
Total decommissioning obligations at beginning of year	**44,729**	36,321
Obligations settled	**(87)**	(1,987)
Obligations disposed of	**-**	(36)
Obligations incurred	**550**	646
Change in estimate	**17**	7,601
Foreign currency translation	**628**	431
Accretion expense	**290**	1,753
Total decommissioning obligations at end of period	**46,127**	44,729
Recorded as folows:		
Decommissioning obligations to be incurred within one year	**750**	750
Decommissioning obligations to be incurred beyond one year	**45,377**	43,979
Total decommissioning obligations at end of period	**46,127**	44,729

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.

Future Accounting Policies:

The International Accounting Standards Board has issued new standards and amendments to existing standards that have been issued but are not yet effective. The following may have an impact on the Company's consolidated financial statements. The impact, if any, has not been determined.

(a) IFRS 11 – Acquisitions of Interests in Joint Operations

(b) IFRS 15 – Revenue from Contracts and Customers

(c) IFRS 9 – Financial Instruments

Disclosure Controls and Procedures

There were no changes in disclosure controls and procedures during the interim period commencing January 1, 2015 and ending March 31, 2015.

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. Utilizing the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") Internal Control – Integrated Framework (2013), Arsenal's management has evaluated, or caused to be evaluated under their supervision, the design and effectiveness 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 in internal controls over financial reporting during the interim period commencing January 1, 2015 and ending March 31, 2015.