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)	**2015**	**2014**	**2015**	**2014**
FINANCIAL				
Oil and gas revenue	**11,528**	25,283	**55,082**	117,114
Cash provided by operating activities	**1,728**	25,392	**27,397**	48,275
Funds from operations	**2,531**	16,906	**30,354**	54,563
Per share - basic	**0.13**	0.98	**1.63**	3.29
Per share - diluted	**0.13**	0.95	**1.62**	3.22
Cash and stock dividends paid	**388**	1,186	**1,688**	4,378
Per share	**0.020**	0.070	**0.090**	0.265
Net income (loss)	**(26,499)**	15,367	**(43,980)**	25,641
Per share - basic	**(1.37)**	0.89	**(2.37)**	1.55
Per share - diluted	**(1.37)**	0.81	**(2.37)**	1.54
Total debt	**53,816**	65,198	**53,816**	65,198
Capital expenditures	**2,699**	9,025	**20,302**	53,534
Property acquisitions	-	**-**	**-**	152
Property dispositions	**(26)**	(100)	**(1,882)**	(100)
Common Share Trading Range				
High	**1.94**	9.25	**6.72**	9.80
Low	**1.05**	5.25	**1.05**	4.52
Close	**1.22**	6.77	**1.22**	6.77
Average daily volume	**24,193**	24,524	**22,420**	25,091
Shares outstanding - end of period	**19,423**	17,877	**19,423**	17,877
OPERATIONAL				
Daily production				
Heavy oil (bbl/d)	**4**	49	**19**	45
Medium oil and NGL's (bbl/d)	**1,617**	2,000	**1,662**	1,890
Light oil and NGLs (bbl/d)	**1,095**	1,651	**1,218**	1,549
Natural gas (mcf/d)	**3,731**	6,247	**4,856**	6,098
Oil equivalent (boe/d @ 6:1)	**3,338**	4,742	**3,707**	4,500
Realized commodity prices ($Cdn.)				
Heavy oil (bbl)	**16.54**	75.01	**42.48**	79.58
Medium oil and NGL's (bbl)	**40.42**	66.18	**46.18**	81.40
Light oil and NGLs (bbl)	**48.02**	70.94	**51.28**	88.15
Natural gas (mcf)	**1.96**	3.46	**2.25**	4.41
Oil equivalent (boe @ 6:1)	**37.54**	57.96	**40.70**	71.30
Netback ($ per boe)				
Revenue	**37.54**	57.96	**40.70**	71.30
Royalty	**(7.44)**	(12.19)	**(8.50)**	(15.41)
Operating and transportation	**(17.73)**	(17.58)	**(16.18)**	(18.73)
Operating netback per boe	**12.36**	28.18	**16.03**	37.16
General and administrative	**(2.85)**	(1.59)	**(3.03)**	(2.45)
Cash portion of share based compensation	**-**	-	**(0.09)**	-
Interest and other financing	**(1.82)**	(1.56)	**(1.60)**	(1.69)
Realized gain (loss) on risk management contracts	**(0.25)**	14.62	**10.96**	0.75
Other (FX and current tax)	**0.80**	(0.90)	**0.16**	(0.54)
Fund from operations per Boe	**8.24**	38.75	**22.43**	33.22

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 Total 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 current or long term).

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

2015 Financial and Operating Highlights

As a result of the severe drop in crude prices that started in Q4 2014 and continued throughout 2015, the Company, in early 2015, undertook certain initiatives to maintain its financial strength and preserve balance sheet flexibility. These initiatives included reducing the dividend, lowering the Company's capital budget, deferring development drilling to focus 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, lowering director fees and freezing employee salaries. Additionally during 2015, the Company undertook a numerous additional actions to lower its cost structure such as eliminating several head office positions, limiting the use of consultants, reducing operating costs and reviewing and reducing other general and administrative expenses. The end result of these initiatives has been to reduce spending on capital and exploration and evaluation expenses from $57.5 million in 2014 to $23.7 million in 2015, to achieve a reduction in operating and transportation costs of approximately 29% from $30.8 million in 2014 to $21.9 million in 2015 and to lower ongoing general and administrative expenditures as well as interest and other financing costs. These cost reductions and other initiatives have resulted in reduced debt - from $65.2 million at December 31, 2014 to $53.8 million at December 31, 2015.

Dividends

During 2015, in response to the continuing sharp drop in commodity prices and in order to preserve capital and maintain future liquidity, the Company dropped the quarterly dividend from $0.07 per share in November 2014 to $0.02 per share in May 2015 and suspended the dividend in January 2016. In 2015, the Company returned approximately $1.7 million in cash or common shares of Arsenal to shareholders who participate in the Share Dividend Plan. Reinstatement of the dividend will depend on the timing and extent of the recovery in commodity prices.

Operating Margins and Funds from Operations

For Q4 2015, Arsenal's operating margin dropped $8.5 million to total $3.8 million or $12.36 per Boe versus $12.3 million or $28.18 per Boe for Q4 2014. For 2015, Arsenal's operating margin dropped by $39.3 million to total $21.7 million or $16.03 per Boe compared to $61.0 million or $37.16 per Boe for 2014. Lower commodity prices, down by 35% in Q4 2015 from Q4 2014 and by 43% in 2015 from 2014 and lower production, down 30% in the current quarter and 18% for the current year from prior comparative periods, are the causes of this drop.

For Q4 2015, Arsenal's funds from operations dropped $14.4 million to total $2.5 million or $8.24 per Boe versus $16.9 million or $38.75 per Boe for Q4 2014. For 2015, Arsenal's funds from operations dropped by $24.2 million to total $30.4 million or $22.43 per Boe compared to $54.6 million or $33.22 per Boe for 2014.

Reduced operating income (down by $8.5 million) and lower realized gains on the monetization of commodity risk management contracts are attributable to the drop in Q4 2015 funds from operations from Q4 2014. In Q4 2014, the Company realized $6.4 million or $14.62 per Boe on commodity risk management contracts.

Reduced operating income (down by $39.3 million) in 2015 is primarily responsible for the drop in funds from operations in 2015. This drop was partially offset by $13.8 million or $11.13 per Boe of increased realized gains on the monetization of commodity risk management contracts in 2015 over 2014. Other cash costs in the current quarter and in the current year were in total generally lower than in the comparable periods.

Production

Production for Q4 2015 averaged 3,338 Boe per day (81% crude oil and NGL and 19% natural gas) versus 3,585 Boe per day in Q3 2015 (79% crude oil and NGL and 21% natural gas) and 4,742 Boe per day in Q4 2014 (78% crude oil and NGL and 22% natural gas). For the year ended December 31, 2015, production averaged 3,707 Boe per day (78% crude oil and NGL and 22% natural gas) versus 4,500 Boe per day (77% crude oil and NGL and 23% natural gas) for the year ended December 31, 2014.

Average production was down 7% or 247 boe per day from Q3 2015 and decreased in both Canada and the US. In Canada production was down due to natural production declines, to uneconomic wells being shut-in and production curtailments for required repairs and maintenance of facilities particularly at Desan. In the US production was down as wells at Stanley and Lindahl in North Dakota experienced their natural and expected decline during the quarter and wells recently drilled at Lindahl have not yet been put on full continued production.

Net Cash from Operating Activities

Net cash from operating activities in Q4 2015 totaled $1.7 million versus $25.4 million generated in Q4 2014 and for 2015 totaled $27.4 million versus $48.3 million for 2014. Changes in operating income, 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.

Net Debt

At December 31, 2015, the Company's credit facility included a $45.0 million Extendable Syndicated Credit Facility, a $10.0 million Extendable Operating Credit Facility and a $5.0 million Supplemental Credit Facility. The semi-annual review of the borrowing base, originally scheduled to be completed on or before November 30, 2015 was not completed until January 8, 2016. The revised credit facility included a $30.0 million Extendable Syndicated Credit Facility, a $10.0 million Extendable Operating Credit Facility and a $15.0 million Supplemental Credit Facility (together the "Facility"). The Supplemental Credit Facility was drawn at $15.0 million, is required to be repaid by May 26, 2016 and bears a margin of 2% higher than the Extendable Syndicated Credit Facility. Proceeds from any common share equity issues (not including proceeds from the sale of flow-through shares) and from the sale of properties are required to be applied to reduce the Supplemental Facility.

Net debt at December 31, 2015 was $53.8 million, down from $65.2 million at December 31, 2014. Net debt has decreased from December 31, 2014 due to net proceeds from a private placement in July 2015 of $4.2 million and exploration and valuation expenses and capital expenditures together totaling less than cash from operations. Capital expenditures in Q4 2015 included the remaining flow-through share expenditures from the flow-through share issues entered into in 2014.

Going Concern

Uncertainties exist as to the Company's ability to continue as a going concern exist due to:

- A $15 million scheduled repayment of the supplemental facility on May 26, 2016. The Company does not currently have sufficient funds to repay this amount;
- There is uncertainty as to the determination of the borrowing base that will be provided by the lenders in May 2016.;
- There is risk that the Company will not be able to comply with the financial covenant in 2016. Compliance is impacted by the undrawn debt which is at risk. In the event the Company has a covenant violation, this would represent an event of default under the credit facility which could result in all outstanding amounts being payable on demand; and

- The Company is required to expend $2.1 million in 2016 on qualifying expenditures by December 31, 2016 to satisfy the requirements of the flow-through share issuance completed in 2015.

As a result of the above matters, there is a material uncertainty as to the Company's ability to continue as a going concern.

Total Debt Reconciliation

(000's Cdn. $)	Year Ended December 31
Net debt December 31, 2014	**65,198**
Funds from operations	**(30,354)**
Net proceeds from sale of shares	**(4,229)**
Additions to property, plant and equipment	**20,302**
Exploration and evaluation expenses	**3,409**
Dividends	**1,418**
Decommissioning liabilities settled	**1,587**
Proceeds on sale of properties	**(1,882)**
Foreign exchange gain on US cash held	**(419)**
Change in non-cash working capital and other items	**(1,212)**
Total debt December 31, 2015	**53,816**

Private Placement

On July 14, 2015, the Company closed a private placement for gross proceeds of $4.6 million ($4.2 million net) issuing 778,460 common shares at $3.15 per common share and 585,700 flow-through common shares at $3.70 per flow-through common share. The proceeds from the common shares were used to reduce amounts outstanding under the Company's Supplemental Credit Facility while the proceeds from the flow-through shares will be used to incur Canadian Exploration Expenses that were renounced to investors of flow-through shares effective December 31, 2015. The expenditures are required to be incurred by December 31, 2016.

Net Income (Loss)

The Company recorded a net loss in Q4 2015 of $26.5 million or $1.37 per share basic and diluted versus income of $15.4 million or $0.89 per share basic and $0.81 per share diluted in Q4 2014. During the current quarter, the Company's operating income dropped by $8.5 million or 64% from Q4 2014 due to lower commodity prices that decreased 35% and to a 30% drop in Q4 2015 average production from Q4 2014. As a result of lower land sale prices and deferred drilling plans, the Company recognized an impairment of its exploration and evaluation assets of $844,112 and due to significantly lower commodity prices recognized an impairment of its property plant and equipment carrying value of $35.7 million. Offsetting these items was an unrealized gain of $1.3 million on foreign exchange and a recovery of income taxes of $12.6 million.

As a result of the impairments recorded in Q3 and Q4 2015, the Company, for the year ended December 31, 2015, recorded a loss of $44.0 million or $2.37 per share basic and diluted versus income of $25.6 million or $1.55 per share basic and $1.54 per share diluted. Operating income for the year ended December 31, 2015 was down $39.3 million or 64% as prices declined 43% and production declined 18% versus the year ended December 31, 2014. In addition, losses on the sale of properties of $1.5 million and impairments totaling $57.8 million of exploration and evaluation assets and property, plant and equipment assets further contributed to the loss recorded in 2015. These items were offset by realized gains on crude risk management contracts of $15.1 million, a recovery of previously expensed share-based compensation of $688,936, a gain on foreign exchange of $6.6 million and the recovery of income tax previously provided of $21.3 million.

Capital Expenditures

Capital expenditures on property, plant and equipment for 2015 totaled $20.3 million down from $53.0 million in 2014. In Canada, the Company spent $12.8 million in 2015 versus $24.1 million in 2014 and in the US, the Company spent $7.5

million in 2015 versus $28.9 million in 2014. Expenditures in Canada were on land purchases, drilling, completions and well equipment and on facilities at Provost, Evi and Princess and in the US were on drilling, completions, well equipment and production facilities at Lindahl.

Due to low commodity prices and the Company's success at Princess, Alberta, the Company did not expend any funds on exploration and evaluation assets in 2015 versus $486,532 expended in 2014.

Corporate Information

As of March 7, 2016, Arsenal has 19,422,976 common shares, 506,237 stock options and 341,998 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 2,168 Boe per day for Q4 2015. In the US, the Company operates under its 100% indirectly owned subsidiary Arsenal Energy USA Inc. and had average production of 1,170 Boe per day for Q4 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 and year ended December 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, 2015. 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 March 7, 2016.

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 income", "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) to measure debt to funds flow ratios that determine interest costs to the Company under its credit facility. The Company used funds from operations to analyze the Company's performance and the ability of the Company to generate the cash flow necessary to fund dividends, growth through capital investment and to repay net 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 sales 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 Q4 2015 to Q4 2014 and for the year ended December 31, 2015 to the year ended December 31, 2014:

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
Net cash from operating activities	**1,728**	25,392	(93)	**27,397**	48,275	(43)
Exploration and evaluation expenses	**581**	978	(41)	**3,409**	4,010	(15)
Decommissioning obligations settled	**593**	667	(11)	**1,587**	1,987	(20)
Change in non-cash working capital	**(371)**	(10,131)	(96)	**(2,039)**	291	(801)
Funds from operations	**2,531**	16,906	(85)	**30,354**	54,563	(44)

Net cash from operating activities generated in Q4 2015 totaled $1.7 million versus $25.4 million generated in Q4 2014 and for the year ended December 31, 2015 totaled $27.4 million versus $48.3 million in the year ended December 31, 2014. Net cash from operating activities differs from the Company's calculation of funds from operations due primarily to the Company's policy of expensing exploration and evaluation expenditures, the timing of incurring decommissioning expenditures and to the changes in non-cash working capital items.

For Q4 2015, funds from operations totaled $2.5 million or $8.24 per Boe versus $16.9 million or $38.75 per Boe for Q4 2014. The operating netback for Q4 2015 was $12.36 per Boe versus $28.18 per Boe in Q4 2014. The average price received decreased by $20.42 per Boe in Q4 2015 versus Q4 2014. For 2015, funds from operations dropped by $24.2 million or 44% when compared to 2014. Lower commodity prices, down by 43%, and lower average production, down by 18% reduced 2015 operating income by $39.3 million or 64% from 2014. This decline was offset by a realized gain on commodity risk management contracts of $15.1 million or $11.13 per Boe and lower interest and financing charges.

The following tables compares funds from operations by country and funds from operations per Boe for Q4 2015 to Q4 2014 and for 2015 to 2014. These numbers are referred to throughout the MD&A:

Funds From Operations By Country

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
Canada	**1,776**	10,758	(83)	**24,013**	31,590	(24)
US	**755**	6,148	(88)	**6,341**	22,973	(72)
Funds from operations	**2,531**	16,906	(85)	**30,354**	54,563	(44)

Funds From Operations Per Boe

	Three Months Ended December 31			Year Ended December 31		
($Cdn.)	**2015**	2014	% Change	**2015**	2014	% Change
Canada	**8.90**	39.11	(77)	**27.42**	30.24	(9)
US	**7.01**	38.14	(82)	**13.29**	38.43	(65)
Total	**8.24**	38.75	(79)	**22.43**	33.22	(32)

Past Eight Quarters

The following tables provide a comparison of the previous eight quarters of funds from operating activities to funds from operations, 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.

Funds from Operations

	2015				2014			
(000's Cdn. $)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Net cash from operating activities	**1,728**	6,155	2,405	17,109	25,392	17,628	6,619	7,629
Exploration and evaluation expenses	**581**	285	877	1,666	978	1,112	1,276	644
Transaction costs			-	-	-	-	-	-
Decommissioning obligations settled	**593**	823	84	87	667	719	367	234
Change in non-cash working capital	**(371)**	(1,357)	2,793	(3,102)	(10,131)	(4,465)	3,348	2,546
Funds from operations	**2,531**	5,906	6,159	15,760	16,906	14,994	11,610	11,053

Production

	2015				2014			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Oil and NGL (bbls/d)	**2,716**	2,828	2,925	3,129	3,701	3,857	3,386	2,979
Natural gas (mcf/d)	**3,731**	4,541	5,528	5,648	6,247	5,943	5,435	6,776
Total Boe	**307,102**	329,812	349.956	366,349	436,245	445,996	390,583	369,746
Boe per day	**3,338**	3,585	3.846	4,071	4,742	4,848	4,292	4,108

Production by Country

	2015				2014			
(Boe per day)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Canada	**2,168**	2,380	2,481	2,574	2,990	2,950	2,765	2,741
US	**1,170**	1,205	1,365	1,497	1,752	1,898	1,527	1,367
Total	**3,338**	3,585	3,846	4,071	4,742	4,848	4,292	4,108

Funds from Operations by Country

	2015				2014			
(000's Cdn. $)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Canada	**1,776**	4,716	3,816	13,707	10,758	8,029	6,665	6,137
US	**755**	1,190	2,343	2,053	6,148	6,965	4,945	4,916
Total	**2,531**	5,906	6,159	15,760	16,906	14,994	11,610	11,053

Funds from Operations by Country per Boe

	2015				2014			
(Cdn. $)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Canada	**8.90**	21.54	16.90	59.16	39.11	29.58	26.49	24.87
US	**7.01**	10.74	18.87	15.25	38.14	39.89	35.58	39.96
Total	**8.24**	17.91	17.60	43.02	38.75	33.62	29.72	29.89

Funds from Operations

	2015				2014			
(000's Cdn. $)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Before risk management contracts	**2,531**	4,042	6,221	2,632	10,528	16,351	13,860	12,597
Realized risk management contracts	**-**	1,864	(62)	13,128	6,378	(1,357)	(2,250)	(1,544)
After commodity contracts	**2,531**	5,906	6,159	15,760	16,906	14,994	11,610	11,053

Funds from Operations Netback Per Boe

	2015				2014			
(Cdn. $)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Before risk management contracts	**8.24**	12.26	17.78	7.18	24.13	36.66	35.49	34.07
After risk management contracts	**8.24**	17.91	17.60	43.02	38.75	33.62	29.72	29.89

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 and reductions, 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 wells at Princess, Alberta and in the North Dakota Bakken 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.

2016 OUTLOOK

With WTI currently trading in the $35.00 US per barrel range and with differentials fluctuating, the ability to find and produce oil at a profit is challenging even with improved technology, reduced drilling and operating costs and a weaker Canadian dollar. Survival appears to be the mode for most oil and gas producers. Crude prices need to improve over the short and medium term to ensure a profitable and stable oil industry. Fortunately the strip pricing for crude reflects some improvement in prices and with cost savings as well as the application of additional new technology, the industry will revitalize itself and become vibrant and profitable once again. The Company has determined that managing bank debt and its balance sheet is its top priority. Accordingly, capital expenditures during the first half of 2016 have been curtailed to a minimum and operating expenses and general and administrative expenditures are being further reviewed for cost reduction opportunities. In addition, the Company has entered into processes to market some or all of its US properties as well as various non-core properties in Canada. The goal is to reposition the Company's balance sheet and pursue growth opportunities at the Company's Princess core property by substantially reducing or eliminating the Company's indebtedness.

2016 Focus and Activity

In order to reduce debt and set the Company on sound footing, the Company has entered into a process to sell some or all of its US properties as well as non-core properties in Canada. With success, the Company hopes to substantially reduce or entirely eliminate its debt to focus and pursue growth opportunities at a time when costs are low in its core Princess property that offers attractive economics and where the Company has demonstrated past success.

The Company will limit capital expenditures in 2016 to the later part of 2016 when prices and margins are expected to improve and will focus on tie-ins of previously drilled wells and expending approximately $2.1 million of flow-through funds on exploratory drilling. During 2016, the Company will continue to focus on reducing operating and overhead costs positioning the Company favorably when prices improve.

Production

Production for Q4 2015 averaged 3,338 Boe per day (81% crude oil and NGL and 19% natural gas) versus 3,585 Boe per day in Q3 2015 (79% crude oil and NGL and 21% natural gas) and 4,742 Boe per day in Q4 2014 (78% crude oil and NGL and 22%

natural gas). For the year ended December 31, 2015, production averaged 3,707 Boe per day (78% crude oil and NGL and 22% natural gas) versus 4,500 Boe per day (77% crude oil and NGL and 23% natural gas) for the year ended December 31, 2014.

Average production for Q4 2015 was down 7% or 247 boe per day from Q3 2015 and 30% or 1,404, boe per day from Q4 2014. Average production for 2015 was down 18% or 793 boe per day from 2014. Production decreased in both Canada and the US during Q4 2015 and in 2015 when compared to Q3 2015, Q4 2014 and 2014. In Canada production was down due to natural production declines, to uneconomic wells being shut-in and due to production curtailments for required repairs and maintenance of facilities particularly at Desan. In the US production was down as wells at Stanley and Lindahl in North Dakota experienced their normal decline during the quarter and wells recently drilled at Lindahl have not yet been put on full continued production.

Production Profile

Average Daily Production

	Three Months Ended December 31			Year Ended December 31		
	2015	2014	% Change	**2015**	2014	% Change
Canada						
Heavy oil (bbls)	**4**	49	(92)	**19**	45	(58)
Medium oil and NGL's (bbls)	**1,617**	2,000	(19)	**1,662**	1,890	(12)
Natural gas (mcf)	**3,283**	5,643	(42)	**4,317**	5,568	(22)
Total Boe	**2,168**	2,990	(27)	**2,399**	2,862	(16)
US						
Light oil and NGL's (bbls)	**1,095**	1,651	(34)	**1,218**	1,549	(21)
Natural gas (mcf)	**449**	604	(26)	**539**	530	2
Total Boe	**1,170**	1,752	(33)	**1,308**	1,638	(20)
Corporate						
Heavy oil (bbls)	**4**	49	(92)	**19**	45	(58)
Oil and NGL's (bbls)	**2,712**	3,651	(26)	**2,880**	3,439	(16)
Natural gas (mcf)	**3,731**	6,247	(40)	**4,856**	6,098	(20)
Total Boe	**3,338**	**4,742**	(30)	**3,707**	4,500	(18)

By Commodity

	Three Months Ended December 31			Year Ended December 31		
	2015	2014	% Change	**2015**	2014	% Change
Heavy oil	-	1%	-	**-**	1%	-
Medium oil and NGL's	**48%**	42%	15	**45%**	42%	7
Light oil and NGLs	**33%**	35%	(6)	**33%**	34%	(5)
Natural gas	**19%**	22%	(15)	**22%**	23%	(3)

By Country

	Three Months Ended December 31			Year Ended December 31		
	2015	2014	% Change	**2015**	2014	% Change
Canada	**65%**	63%	3	**65%**	64%	2
US	**35%**	37%	(5)	**35%**	36%	(3)

The percentage of production in Canada versus the percentage of production in the US may change in 2016 as a result of successful second half 2015 drilling at Princess, Alberta, based on the timing of wells waiting to be brought on full production at Lindahl and on the property sale initiatives undertaken. Successful Princess wells drilled in 2015 will be tied-in and brought on-production once prices and margins improve. Production from US drilling at Lindahl has not yet been fully brought on stream. Full production should offset production declines resulting in relatively flat US production period over comparative period.

Production by Area

	Three Months Ended December 31					Year Ended December 31				
	2015		2014			**2015**		2014		
AREA	**Boe/d**	**% of Total**	Boe/d	% of Total	**% Change**	**Boe/d**	**% of Total**	Boe/d	% of Total	**% Change**
Canada										
Galahad (light oil)	**95**	**3**	109	2	**(13)**	**88**	**2**	105	2	**(16)**
Princess (medium oil and gas)	**896**	**27**	1,352	29	**(34)**	**917**	**25**	1,156	26	**(21)**
Chauvin (medium oil and gas)	**254**	**8**	239	5	-	**257**	**7**	257	6	-
Provost (medium oil and gas)	**234**	**7**	355	7	**(34)**	**264**	**7**	376	8	**(30)**
Consort (medium oil and gas)	**55**	**2**	75	2	**(27)**	**61**	**2**	74	2	**(18)**
Evi (light oil)	**254**	**7**	106	2	**140**	**240**	**6**	118	3	**103**
Desan (gas)	**295**	**9**	572	12	**(48)**	**459**	**14**	595	13	**(23)**
Others	**85**	**2**	182	4	**(53)**	**113**	**3**	181	4	**(38)**
Total Canada	**2,168**	**65**	2,990	63	**(27)**	**2,399**	**65**	2,862	64	**(16)**
US										
Stanley (light oil)	**818**	**25**	1,335	28	**(39)**	**963**	**27**	1,302	29	**(26)**
Lindahl (light oil)	**293**	**9**	353	8	**(17)**	**285**	**8**	266	6	**7**
Rennie Lake/Black Slough (light oil)	**44**	**1**	54	1	**(19)**	**48**	**1**	55	1	**(13)**
Lake Darling (light oil)	**15**	**-**	10	-	**50**	**12**	**-**	15	-	**(20)**
Total US	**1,170**	**35**	1,752	37	**(33)**	**1,308**	**35**	1,638	36	**(20)**
Total	**3,338**	**100**	4,742	100	**(30)**	**3,707**	**100**	4,500	100	**(18)**

Revenue

Prices - Before Commodity Contracts

	Three Months Ended December 31			Year Ended December 31		
($Cdn.)	**2015**	2014	% Change	**2015**	2014	% Change
Canada						
Heavy oil per barrel	**16.54**	75.01	(78)	**42.48**	79.58	(47)
Medium oil and NGL's per barrel	**40.42**	66.18	(39)	**46.18**	81.40	(43)
Natural gas per mcf	**1.91**	3.31	(42)	**2.11**	4.27	(51)
Total per Boe	**33.06**	51.76	(36)	**36.10**	63.29	(43)
US						
Heavy oil per barrel	**-**	-	-	**-**	-	-
Light oil and NGL's per barrel	**48.02**	70.94	(32)	**51.28**	88.15	(42)
Natural gas per mcf	**2.32**	4.85	(52)	**3.37**	5.91	(43)
Total per Boe	**45.84**	68.54	(33)	**49.15**	85.30	(42)
Total						
Heavy oil per barrel	**16.54**	75.01	(78)	**42.48**	79.58	(47)
Oil and NGL's per barrel	**43.49**	68.33	(36)	**48.34**	84.44	(43)
Natural gas per mcf	**1.96**	3.46	(43)	**2.25**	4.41	(49)
Total per Boe	**37.54**	57.96	(35)	**40.70**	71.30	(43)

Reference Prices

	Three Months Ended Dececember 31			Year Ended Dececember 31		
	2015	2014	% Change	**2015**	2014	% Change
WTI Cushing, Oklahoma ($U.S./bbl)	**42.18**	73.15	(42)	**48.80**	93.00	(48)
Canadian Light Sweet ($Cdn./bbl)	**52.55**	74.37	(29)	**57.45**	93.99	(39)
Hardisty Heavy 12 API ($Cdn./bbl)	**30.90**	61.41	(50)	**40.42**	76.40	(47)
Hardisty Bow River 24.9 API ($Cdn./bbl)	**37.20**	67.65	(45)	**45.35**	81.67	(44)
AECO (30 day spot) ($Cdn./MMBtu)	**2.47**	3.63	(32)	**2.70**	4.50	(40)
Henry Hub NYMEX Close ($U.S./MMBtu)	**2.24**	3.85	(42)	**2.63**	4.28	(39)
Foreign exchange ($Cdn./$U.S.)	**1.34**	1.14	18	**1.29**	1.10	17

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

In Canada, the Company received $40.42 per barrel for its medium oil and NGL in the current of quarter, a decrease of 39% versus Q4 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 Q4 2015 versus Q4 2014. The price received for natural gas decreased 42% in Canada and 52% in the US in Q4 2015 versus Q4 2014. The price received for natural gas in Canada generally tracks changes to the AECO price which was down 32% from Q4 2014 and in the US, the Henry Hub price was down 42% from Q4 2014.

In the US in Q4 2015, the price received for light oil decreased 32% to $48.02 per barrel. This is less than the 42% decrease in the price of WTI in the current quarter over the comparative quarter in 2014 due primarily to the strength of the US dollar that increased in value vis-à-vis the Canadian dollar by 18%.

The Company received an average price during Q4 2015 of $37.54 per Boe, a decrease of 35% from $57.96 per Boe received in Q4 2014. This decrease is attributed to the 42% decline, during the comparative quarters, in the price of WTI and a decrease in Q4 2015 from Q4 2014 in the price of natural gas in both Canada (AECO) and the US (Henry Hub) of 32% and 42% respectively.

For the year ended December 31, 2015, the Company received an average price of $40.70 per Boe versus $71.30 per Boe received in the year ended December 31, 2014. This decrease of 43% generally corresponds to the decrease in the price of WTI of 48% over the twelve month period. In addition, natural gas prices declined in both Canada (AECO) and the US (Henry Hub) by 40% and 39% respectively while the US dollar strengthened by 17% during 2015.

Revenues

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
Canada						
Heavy oil	**6**	339	(98)	**288**	1,301	(78)
Medium oil and NGL's	**6,014**	12,176	(51)	**28,007**	56,142	(50)
Natural gas	**576**	1,720	(66)	**3,327**	8,678	(62)
Total	**6,596**	14,235	(54)	**31,623**	66,121	(52)
US						
Light oil and NGL's	**4,837**	10,779	(55)	**22,796**	49,848	(54)
Natural gas	**96**	269	(65)	**663**	1,145	(42)
Total	**4,932**	11,048	(55)	**23,459**	50,993	(54)
Total						
Heavy oil	**6**	339	(98)	**288**	1,301	(78)
Oil and NGL's	**10,850**	22,955	(53)	**50,803**	105,990	(52)
Natural gas	**672**	1,989	(66)	**3,990**	9,823	(59)
Oil and natural gas revenues	**11,528**	25,283	(54)	**55,082**	117,114	(53)
Gain (loss) on realized crude commodity contracts	**-**	6,389	100	**15,057**	1,283	(1,074)
Oil and gas revenue after realized crude commodity contracts	**11,528**	31,672	(64)	**70,139**	118,397	(41)
Revenue per boe before realized crude commodity contracts	**37.54**	57.96	(35)	**40.70**	71.30	(43)
Revenue per boe after realized crude commodity contracts	**37.54**	72.60	(48)	**51.83**	72.08	(28)

Oil and natural gas revenues totaled $11.5 million for Q4 2015 a decrease of 54% over Q4 2014 due to a 35% decrease in the average price received per Boe and a 30% decrease in production. For the year ended December 31, 2015, revenues decreased 53% to $55.1 million versus $117.1 million in 2014 due to a 43% decrease in the average price received and an 18% decrease in production. Average price received per Boe in Q4 2015 decreased $18.70 per boe in Canada and $22.70 per Boe in the US from Q4 2014. Average price received per Boe for the year ended 2015 decreased $27.19 per boe in Canada and $36.16 per Boe in the US compared to the year ended December 31, 2014.

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.

In Q1 2015 and Q3 2015, the Company monetized all of its crude financial instrument contracts realizing a gain of $15.1 million. For 2015, the Company recorded a net gain of $14.8 million on its financial instrument (commodity price and interest rate) contracts as a loss of $232,091 was a realized on the Company’s interest rate swap financial contract.

Currently, the Company has no commodity risk management contracts in place.

In order to mitigate the impact of future increases 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	January 1, 2016 - February 13, 2018	$ 30,000,000	CAD - BA - CDOR	1.80%	Swap	(616)

As at December 31, 2015, the Company has an interest rate risk management liability recorded totaling $615,704 of which $295,538 is classified as a current liability.

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

Gains (Losses) on Risk Management Contracts

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
Realized gain (loss)						
Commodity	**-**	6,389	100	**15,057**	1,283	(1,074)
Interest rate	**(75)**	(11)	(585)	**(232)**	(55)	(321)
Total	**(75)**	6,378	101	**14,825**	1,227	(1,108)
Unrealized gain (loss)						
Commodity	**-**	10,779	-	**(11,946)**	15,795	(176)
Interest rate	**80**	(178)	(145)	**(420)**	(141)	198
Total	**80**	10,601	(99)	**(12,366)**	15,654	(179)
Total gain (loss)						
Commodity	**-**	17,168	(100)	**3,111**	17,077	82
Interest rate	**5**	(189)	-	**(652)**	(196)	-
Total risk management contracts	**5**	16,979	(100)	**2,459**	16,881	85
$ Per Boe realized risk management contracts	**(0.25)**	14.62	102	**10.96**	0.75	(1,366)
$ Per Boe unrealized risk management contracts	**0.26**	24.30	(99)	**(9.14)**	9.53	(196)
$ Per Boe total	**0.01**	38.92	(100)	**1.82**	10.28	82

Royalties

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
Canada						
Heavy oil	**(16)**	45	(135)	**14**	157	(91)
Medium oil and NGL's	**875**	2,017	(57)	**4,807**	9,829	(51)
Natural gas	**16**	130	(87)	**53**	892	(94)
Total	**876**	2,192	(60)	**4,875**	10,878	(55)
US						
Light oil and NGL's	**1,393**	3,071	(55)	**6,498**	14,196	(54)
Natural gas	**17**	56	(70)	**128**	242	(47)
Total	**1,410**	3,127	(55)	**6,626**	14,438	(54)
Total						
Heavy oil	**(16)**	45	(135)	**14**	157	(91)
Oil and NGL's	**2,268**	5,088	(55)	**11,305**	24,025	(53)
Natural gas	**33**	186	(82)	**181**	1,135	(84)
Royalties	**2,286**	5,319	(57)	**11,501**	25,317	(55)
Royalties per Boe	**7.44**	12.19	(39)	8.50	15.41	(45)

Percentage By Product

	Three Months Ended December 31			Year Ended December 31		
	2015	2014	% Change	**2015**	2014	% Change
Heavy oil	**-**	13	(100)	**5**	12	(58)
Oil and NGL's	**21**	22	(6)	**22**	23	(2)
Natural gas	**5**	9	(47)	**5**	12	(61)
Total	**20**	21	(6)	**21**	22	(3)

Percentage By Country

	Three Months Ended December 31			Year Ended December 31		
	2015	2014	% Change	**2015**	2014	% Change
Canada	**13**	15	(14)	**15**	16	(6)
US	**29**	28	1	**28**	28	-
Total	**20**	21	(6)	**21**	22	(3)

The Company's overall royalty rate for Q4 2015 averaged 20% compared to 21% for Q4 2014. For the year ended December 31, 2015, the royalty rate averaged 21% versus 22% for the year ended December 31, 2014. Lower prices and lower well production have contributed to reduce royalty rates in Q4 2015 versus Q4 2014 and for 2015 versus 2014.

During the current quarter and for the year ended December 31, 2015, the royalty rate for natural gas has decreased as royalty rates are somewhat price sensitive (down 14% in Q4 2015 and down 6% in 2015).

Looking forward, the corporate royalty rate on current production is expected to average in the 20% - 22% range. In Canada, the rate has fluctuated due to the timing of drilling low royalty rate wells and to some extent, commodity prices and production rates. In early 2016, the Alberta Government has announced a new royalty rate mechanism for 2017 and beyond that introduces a flat 5% royalty rate until payout (as defined) and an unannounced higher rate thereafter that will increase with higher commodity prices. This change will have an impact on future drilling in Alberta in 2017 and beyond. In the US due to the timing of production increases from higher royalty rate wells, increases or decreases in the dollar value of royalties are commodity price related with higher commodity prices resulting in a higher royalties payable and lower commodity prices resulting in a lower royalties payable. In the US, royalties are paid to freehold landowners and a production royalty (or tax) is paid to the State of North Dakota. The rates in the US are essentially fixed and are based on a percentage of revenue. As a result the rate does not change but the dollar value fluctuates with the fluctuation in prices.

Operating and Transportation Expenses

(000's Cdn. $)	Three Months Ended December 31			Year Ended December 31		
	2015	2014	**% Change**	**2015**	2014	% Change
Canada						
Heavy oil	**15**	168	(91)	**316**	659	(52)
Medium oil and NGL's	**3,121**	4,967	(37)	**13,250**	20,077	(34)
Natural gas	**1,055**	1,159	(9)	**3,925**	4,852	(19)
Total	**4,191**	6,294	(33)	**17,491**	25,589	(32)
US						
Light oil and NGL's	**1,233**	1,351	(9)	**4,304**	5,097	(16)
Natural gas	**22**	24	(12)	**97**	82	19
Total	**1,255**	1,375	(9)	**4,402**	5,178	(15)
Total						
Heavy oil	**15**	168	(91)	**316**	659	(52)
Oil and NGL's	**4,354**	6,318	(31)	**17,554**	25,174	(30)
Natural gas	**1,077**	1,183	(9)	**4,022**	4,934	(18)
Operating and transportation	**5,446**	7,669	(29)	**21,893**	30,767	(29)
Operating and transportation per Boe	**17.73**	17.58	1	**16.18**	18.73	(14)

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 Q4 2015 by $2.2 million or 29% from Q4 2014 and by $8.9 million or 29% for the year ended December 31, 2015 versus 2014. On a Boe basis, operating costs increased slightly in Q4 2015 to $17.73 per boe from $17.58 per boe in Q4 2014 and for the year ended December 31, 2015 decreased to $16.18 per Boe versus $18.73 per Boe for the year ended December 31, 2014. Current quarter operating costs increased due to lower average production and higher costs, particularly at Desan and higher costs at Lindahl in the US while the general reduction in operating costs in 2015 is due to a cost savings on electricity and to the electrification of some well sites, lower service costs, the shutting in of high cost uneconomic wells and general operational efficiencies.

Operating Netback per Boe

($Cdn.)	Three Months Ended December 31 2015 Canada	US	Corporate	Three Months Ended December 31 2014 Canada	US	Corporate	Corporate % Change
Heavy oil							
Revenue	**16.54**	**-**	**16.54**	75.01	-	75.01	**(78)**
Royalty	**42.83**	**-**	**42.83**	(9.96)	-	(9.96)	**(530)**
Operating and transportation	**(41.20)**	**-**	**(41.20)**	(37.14)	-	(37.14)	**11**
Operating netback per barrel	**18.17**	**-**	**18.17**	27.91	-	27.91	**(35)**
Medium and light oil and NGL's							
Revenue	**40.42**	**48.02**	**43.49**	66.18	70.94	68.33	**(36)**
Royalty	**(5.88)**	**(13.83)**	**(9.09)**	(10.96)	(20.21)	(15.15)	**(40)**
Operating and transportation	**(20.97)**	**(12.24)**	**(17.45)**	(27.00)	(8.89)	(18.81)	**(7)**
Operating netback per barrel	**13.56**	**21.94**	**16.94**	28.22	41.84	34.38	**(51)**
Natural gas							
Revenue	**1.91**	**2.32**	**1.96**	3.31	4.85	3.46	**(43)**
Royalty	**(0.05)**	**(0.41)**	**(0.10)**	(0.25)	(1.01)	(0.32)	**(70)**
Operating and transportation	**(3.49)**	**(0.52)**	**(3.14)**	(2.23)	(0.44)	(2.06)	**52**
Operating netback per mcf	**(1.64)**	**1.39**	**(1.28)**	0.83	3.40	1.08	**(218)**
Boe							
Revenue	**33.06**	**45.84**	**37.54**	51.76	68.54	57.96	**(35)**
Royalty	**(4.39)**	**(13.10)**	**(7.44)**	(7.97)	(19.40)	(12.19)	**(39)**
Operating and transportation	**(21.01)**	**(11.66)**	**(17.73)**	(22.88)	(8.53)	(17.58)	**1**
Operating netback per Boe	**7.67**	**21.07**	**12.36**	20.90	40.61	28.18	**(56)**

($Cdn.)	Year Ended December 31 2015 Canada	US	Corporate	Year Ended December 31 2014 Canada	US	Corporate	Corporate % Change
Heavy oil							
Revenue	**42.48**	**-**	**42.48**	79.58	-	79.58	**(47)**
Royalty	**(2.13)**	**-**	**(2.13)**	(9.60)	-	(9.60)	**(78)**
Operating and transportation	**(46.57)**	**-**	**(46.57)**	(40.33)	-	(40.33)	**15**
Operating netback per barrel	**(6.22)**	**-**	**(6.22)**	29.65	-	29.65	**(121)**
Medium and light oil and NGL's							
Revenue	**46.18**	**51.28**	**48.34**	81.40	88.15	84.44	**(43)**
Royalty	**(7.93)**	**(14.62)**	**(10.76)**	(14.25)	(25.10)	(19.14)	**(44)**
Operating and transportation	**(21.85)**	**(9.68)**	**(16.70)**	(29.11)	(9.01)	(20.06)	**(17)**
Operating netback per barrel	**16.41**	**26.98**	**20.88**	38.04	54.03	45.24	**(54)**
Natural gas							
Revenue	**2.11**	**3.37**	**2.25**	4.27	5.91	4.41	**(49)**
Royalty	**(0.03)**	**(0.65)**	**(0.10)**	(0.44)	(1.25)	(0.51)	**(80)**
Operating and transportation	**(2.49)**	**(0.50)**	**(2.27)**	(2.39)	(0.42)	(2.22)	**2**
Operating netback per mcf	**(0.41)**	**2.22**	**(0.12)**	1.44	4.24	1.69	**(107)**
Boe							
Revenue	**36.10**	**49.15**	**40.70**	63.29	85.30	71.30	**(43)**
Royalty	**(5.57)**	**(13.88)**	**(8.50)**	(10.41)	(24.15)	(15.41)	**(45)**
Operating and transportation	**(19.97)**	**(9.22)**	**(16.18)**	(24.49)	(8.66)	(18.73)	**(14)**
Operating netback per Boe	**10.57**	**26.04**	**16.03**	28.38	52.49	37.16	**(57)**

Canadian Netback

The Q4 2015 operating netback from Canadian medium oil and NGL decreased $14.66 per barrel or 52% from Q4 2014. For 2015, the netback decreased by $21.63 per barrel or 57% to $16.41 per barrel from $38.04 per barrel for the year ended December 31, 2014. Lower average crude prices in 2015 were offset by lower operating expenses. The average price received decreased by 39% in the quarter and 43% during the year ended December 31, 2015. Meanwhile operating expenses decreased 22% in the current quarter and 25% in 2015 from 2014.

The Q4 2015 operating netback from Canadian heavy oil production was $18.17 (due to a prior period royalty adjustment) compared to $27.91 in Q4 2014. For the year ended December 31, 2015, the operating netback from Canadian heavy oil production was negative due to low prices and high operating expenses. This production is being shut-in until prices recover.

The Q4 2015 netback from Canadian natural gas decreased $2.47 per mcf to a loss of $1.64 per mcf from Q4 2014 due to lower prices that declined by 42% or $1.40 per mcf when compared to Q4 2014 and due to facility downtime resulting in lower volumes. For the year ended December 31, 2015, the netback from Canadian natural gas decreased $1.85 per mcf or 129% to a loss of $0.41 per mcf due to lower prices that declined by 51% or $2.16 per mcf when compared to the year ended December 31, 2014.

US Netback

The Q4 2015 netback from the US light oil and NGL decreased $19.90 per barrel or 48% from Q4 2014 and by $27.05 or 50% in 2015 from 2014. Lower crude prices, down 32% on a quarter over comparative quarter basis and 42% on a comparative year basis were responsible for this decline.

The Q4 2015 netback from the US natural gas decreased $2.01 per mcf or 59% from Q4 2014 and by $2.02 or 48% in the year ended December 31, 2015 versus 2014. These declines are due to lower prices that declined by 52% in the current quarter and by 43% in the current twelve month period from prior year comparative periods.

Corporate Netback

Arsenal's Q4 2015 average price decreased $20.42 per Boe or 35% to $37.54 per Boe from $57.96 per Boe received in Q4 2014 resulting in a reduced netback of $15.82 per Boe to $12.36 per Boe. For the year ended December 31, 2015, the corporate netback decreased 57% to $16.03 per Boe due to a lower average price that declined by 43%.

General and Administrative Expenses

	Three Months Ended December 31			**Year Ended December 31**		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
Gross expenditures	**1,478**	1,504	(2)	**6,535**	7,013	(7)
Overhead recovery	**(432)**	(557)	(22)	**(1,724)**	(2,127)	(19)
Capitalized overhead	**(170)**	(253)	(33)	**(715)**	(860)	(17)
Net general and administrative expense	**875**	693	26	**4,096**	4,026	2
Net general and administrative per boe	**2.85**	1.59	79	**3.03**	2.45	23

Gross general and administrative expenditures were lower in Q4 2015 by $26,169 and lower in 2015 by $477,874 when compared to their respective 2014 periods. On a net basis, general and administrative expenses increased in Q4 2015 over Q4 2014 by $181,833 and by $69,669 in 2015 versus 2014. Net expenditures were impacted by the decision to defer and cancel some drilling plans that resulted in reduced overhead capitalized. In addition, overhead recoveries were reduced due to a lower capital budget and from the shut-in of certain uneconomic wells.

With the reduction in the Company's funds from operations in 2015 and with continued declines in commodity prices and lower production expected in 2016, the Company initiated certain cost reductions initiatives including a reduced staff level, a movement to part time employees and consultants, reduced hours and the Company eliminated bonuses for 2015. These initiatives, resulted in increased severance costs in the short term but are expected to result in lower gross and net costs going forward. With the further decline in commodity prices in 2016, the Company is further reviewing staff levels and expenditures levels with a view to further reducing costs.

On a Boe basis, general and administrative expenditures for the current quarter increased to $2.85 per Boe from $1.59 per Boe for Q4 2014 and for 2015 to $3.03 per Boe from $2.45 per Boe in 2014. These increases are due to lower production which is down 30% in the current quarter and 18% in 2015 from the prior comparative periods, the costs related to reducing staff and reduced overhead recovery and overhead capitalized.

The Company has entered into a process to sell all or a portion of its US properties and non-core properties in Canada with net proceeds applied to reduce debt. Depending on the outcome of the sales process, the Company expects to further reduce the head office staff and costs. With continuing low commodity prices and margins, the Company has and will continue to take steps to reduce general and administrative expenditures in 2016.

Exploration and Evaluation Expenses

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
Exploration and evaluation expenses	**580**	978	(41)	**3,409**	4,010	(15)
Per Boe	**1.89**	2.24	(16)	**2.52**	2.44	3

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

Exploration and Evaluation Asset Impairment

Exploration and Evaluation Impairment

	Three Months Ended Dececember 31			Year Ended Dececember 31		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
Exploration and evaluation write-down	**844**	5,199	(84)	**2,025**	5,199	(61)
Per Boe	**2.75**	**11.92**	(77)	**1.50**	**3.16**	(53)

The carrying amounts of the Company's exploration and evaluation assets are reviewed at each reporting date to determine whether there is any indication of impairment in carrying value. If any such indication exists, then the assets fair value is estimated based on fair value less costs to sell.

On September 30, 2015 and on December 31, 2015, indicators of impairment in the form of lower average land acreage prices, lower commodity prices and the decision to defer further exploration activities existed at Blackstone. In addition, the abandonment of a well drilled in late Q3 2015 at Provost and the decision to defer further drilling indicated an impairment of lands at Provost. Based on an estimation of fair value of the Company's exploration and evaluations assets versus the carrying value of those assets, a write-down of $844,112 was recorded in Q4 2015. For 2015, $2.0 million has been recorded related to the impairment of the Company's lands in the Blackstone (Columbia) and Provost areas, both in Alberta.

Property, Plant and Equipment Impairment

Property, Plant and Equipment Impairment

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2015**	**2014**	% Change	**2015**	2014	% Change
Property, plant and equipment impairment	**35,666**	-	-	**55,816**	-	-
Per Boe	**116.14**	-	-	**41.25**	-	-

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 indicators 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 September 30, 2015, indicators in the form of significantly lower commodity prices and deferred development plans existed. Lower commodity prices and deferred development have the effect of lowering the estimated future cash flows of CGU's and potentially the carrying value of that CGU. The Company conducted an impairment test on its CGU's and based on the value in use determined that impairment existed in three of the Company's CGU's – Alberta medium oil, the Company's natural gas CGU and in the US CGU. An impairment provision of $20.2 million has been recorded ($4.2 million related to the Company's Alberta medium oil CGU, $1.0 million related to the Company's natural gas CGU and $15.0 ($11.2 million US) related to the Company's US CGU.

On December 31, 2015, given that the Company has initiated a process to sell all or a portion of its US properties as well as various non-core properties in Canada and low commodity prices, the Company assessed its various CGU's for impairment. Based on estimates of the fair market value of the Company's US CGU less costs to sell, an impairment of $30.4 million was recorded in the Company's US CGU. Based on a combination of fair market value less costs to sell and value in use, an impairment of $5.2 million was recorded on the Company's Canadian CGU's.

No impairment was recorded in 2014.

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 Charges

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
Interest and other financing charges	**559**	681	(18)	**2,159**	2,775	(22)
Per Boe	**1.82**	1.56	17	**1.60**	1.69	(6)

Interest and other financing charges include interest, bank charges and fees and other levies 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 18% in Q4 2015 from Q4 2014 and 22% in 2015 versus 2014 due primarily to lower average bank borrowings. For Q4 2015, the average daily borrowing balance was $51.1 million versus $69.4 million for Q4 2014. For the year ended December 31, 2015, the average daily borrowing balance was $52.6 million versus $71.6 million for 2014.

Interest rates on the Operating Credit Facility range from Canadian or US prime plus 1.00% to 3.50% on prime based loans and on the Syndicated Credit Facility range from the base rate plus 2.00% to 4.50% on bankers' acceptances and on Libor based loans. The increment is determined based on the Company's debt to cash flow ratio as calculated under the provisions of the agreement. Interest rates on the Supplemental Credit Facility are 2% higher that on the Syndicated Credit Facility. Borrowings of $12.0 million on the Supplemental Credit Facility commenced on May 28, 2015. Since May, the Company has reduced this facility to $5.0 million as of December 31, 2015.

The Company's credit facility was reviewed and renewed in early 2016 see disclosure under "Credit Facility" located below in this MD&A.

Depletion and Depreciation

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
Depletion and depreciation	**5,545**	8,194	(32)	**26,707**	30,853	(13)
Per boe	**18.06**	18.78	(4)	**19.74**	18.78	5

On an absolute dollar basis, depletion and depreciation in Q4 2015 decreased 32% from Q4 2014. This decrease was attributed primarily to a 30% decrease in average production offset by a lower depletion rate per Boe.

On a Boe basis, depletion and depreciation decreased 4% to $18.05 per Boe in Q4 2015 versus $18.78 per Boe in Q4 2014 and decreased 4% in 2015 from 2014. The decrease is due to positive reserve adjustments in both Canada and the US and lower future development costs in the US and impairments recorded in Q3 2015.

On an absolute dollar basis, depletion and depreciation for 2015 decreased 13% from 2014 due to lower production. On a Boe basis, depletion and depreciation increased 5% to $19.74 per Boe in 2015 versus $18.78 per Boe in 2014.

In Canada, the depletion and depreciation rate decreased slightly in 2015 from $16.69 per Boe to $15.81 per Boe based on an increase in reserves primarily at Princess but also at Chauvin/Ribstone and Desan, a decrease in the cost estimate to abandon and decommission wells and Q3 2015 impairment of Canadian CGU's.

In the US, the depreciation and depletion rate increased in 2015 from $22.45 per Boe 2014 to $26.94 per Boe in 2015 due primarily to a stronger US dollar (up 17% from December 31, 2014).

Accretion

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2015**	**2014**	% Change	**2015**	2014	% Change
Accretion	**245**	368	(33)	**1,108**	1,753	(37)
Per boe	**0.80**	0.84	(5)	**0.82**	1.07	(23)

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 for 2015 decreased by 23% from 2014 due primarily to lower expected costs. The 2014 provision included expenditures to decommission certain wells over and above the decommissioning estimate recorded.

Share-based Compensation

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
Share-based compensation expense (recovery)						
Cash portion	**-**	-	-	**125**	-	-
Non-cash portion	**153**	(1,009)	(115)	**(815)**	1,797	(145)
	153	(1,009)	(115)	**(690)**	1,797	(138)
Share-based compensation expense (recovery)						
Cash portion - $ per Boe	**-**	**-**	-	**0.09**	-	-
Non-cash portion - $ per Boe	**0.50** -	2.31	(122)	**(0.60)**	1.09	(155)
$ Per boe	**0.50** -	2.31	(122)	**(0.51)**	1.09	(147)

The Company has a share option plan and a share award incentive plan. The Company discontinued any further grants of options under the share option plan. Options current outstanding will expire at the end of their respective terms in 2016, 2017 and 2018.

The Company has determined that, in certain circumstances, it will cash settle stock options and a portion of the Company's share awards. As a result of changes to the Company's share price and vesting, 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 an expense to share-based compensation in the current quarter of $153,178 resulting in a 2015 recovery prior period expenses of $688,936. No share-based compensation has been capitalized during 2015 or 2014.

As no options are currently in-the-money, the Company has not recorded an incentive (share-based) compensation liability related to the cash settling of options as the option strike price and remaining term indicate that is unlikely the options will be exercised or cash settled. A liability of $79,290 related to the share award plan has been recorded as a current liability.

Foreign Exchange

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
Realized loss (gain)	**70**	187	-	**(53)**	(76)	30
Unrealized loss (gain)	**(1,264)**	(1,293)	105	**(6,645)**	(2,694)	(147)
Total foreign exchange loss (gain)	**(1,194)**	(1,105)	(8)	**(6,698)**	(2,770)	(142)
$ per Boe realized loss (gain)	**0.23**	0.43	-	**(0.04)**	(0.05)	15
$ per Boe unrealized loss (gain)	**(4.12)**	(2.96)	(39)	**(4.91)**	(1.64)	(199)
$ per Boe total	**(3.89)**	(2.53)	(53)	**(4.95)**	(1.69)	(194)

Foreign exchange gains and losses are recognized based on the fluctuation of the Canadian and US dollar exchange rate and on the timing of the funding and repayment of funds advanced from the Company and its US operating subsidiary.

Sale of Properties

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
(Gain) loss on sale of property	**(97)**	**-**	-	**1,467**	-	-
Per boe	**(0.31)**	**-**	-	**1.08**	**-**	-

During Q4 2015, the Company sold minor interests in two properties recording a gain on the sale of $96,717. For 2015, the Company recorded a loss on the sale of minor non-core property interests of $1.5 million. The Company will continue to sell properties, in whole or in part where the Company deems there to be no significant exploration or development upside, where operating costs are high or where the exposure to decommissioning liabilities can be cost effectively eliminated. Given the nature of the properties the Company is attempting to sell and the state of the current oil and natural gas environment and prices and the impairments recorded, it is expected that any future minor non-core property sales will result in minor accounting gains or losses for the Company.

Provision for Income Taxes

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $)	**2015**	**2014**	% Change	**2015**	2014	% Change
Current tax expense (recovery)	**(314)**	204	(254)	**(168)**	969	(117)
Deferred tax expense (recovery)	**(12,562)**	(298)	4,115	**(21,103)**	3,658	(677)
Total	**(12,876)**	(94)	13,598	**(21,271)**	4,627	(560)
$ Per Boe - current expense	**(1.02)**	0.47	(319)	(0.12)	0.59	(121)
$ Per Boe - deferred tax recovery	**(40.90)**	(0.68)	5,888	(15.59)	2.23	(800)
$ Per boe - Total	**(41.93)**	(0.22)	19,358	(15.72)	2.82	(658)

For the year ended December 31, 2015, the Company recorded income tax recovery of $21.3 million. In Canada, the loss before taxes for 2015 was $13.0 million and in the US, the 2015 loss before taxes was $52.3 million.

In Canada, the Company has not recorded any recovery of income tax as the Company has accumulated losses from Canadian operations and has estimated Canadian tax pools in excess of $85.0 million at December 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 2015 of approximately $9.7 million recognizing $1.6 million of the recorded premium. The Company has a long-term liability (flow-through share issue premium) of $315,177 related to approximately $2.1 million of remaining qualifying expenditures required to be incurred by December 31, 2016.

In the US, the loss, before income taxes of $52.3 million resulted in a recovery totaling $19.6 million. The recovery consists of $19.5 million in recovery of income tax and a recovery of $168,224 of current tax payable relating to Alternate Minimum Tax ("AMT" see below). In the US, the Company has estimated tax pools in excess of $43.9 (US $31.7) million at December 31, 2015.

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 December 31, 2015, the deferred tax liability recorded in the Company's Statement of Financial Position of $4.4 million relates entirely to the US operations. The US deferred tax liability increases and decreases not only based on accounting income and loss but also due to increases and decreases in the Canadian/US exchange rate.

Net Income (Loss) per Boe

($Cdn.)	Three Months Ended December 31 **2015**	2014	Year Ended December 31 **2015**	2014
Oil and gas revenue	**37.54**	57.96	**40.70**	71.30
Royalties	**(7.44)**	(12.19)	**(8.50)**	(15.41)
Operating and transportation	**(17.73)**	(17.58)	**(16.18)**	(18.73)
Operating netback per Boe	**12.36**	28.18	**16.03**	37.16
Realized gain (loss) on risk management contracts	**(0.25)**	14.62	**10.96**	0.75
Realized gain on foreign exchange	**(0.23)**	(0.43)	**0.04**	0.05
General and administrative	**(2.85)**	(1.59)	**(3.03)**	(2.45)
Share-based compensation - cash portion	**-**	-	**(0.09)**	-
Interest and other financing charges	**(1.82)**	(1.56)	**(1.60)**	(1.69)
Current tax expense	**1.02**	(0.47)	**0.12**	(0.59)
Funds from operations netback per Boe	**8.24**	38.75	**22.43**	33.22
Unrealized gain (loss) on risk management contracts	**0.26**	24.30	**(9.14)**	9.53
Unrealized gain on foreign exchange	**4.12**	2.96	**4.91**	1.64
Depletion and depreciation	**(18.06)**	(18.78)	**(19.74)**	(18.78)
Accretion	**(0.80)**	(0.84)	**(0.82)**	(1.07)
Exploration and evaluation impairment	**(2.75)**	(11.92)	**(1.50)**	(3.16)
Property, plant and equipment impairment	**(116.13)**	-	**(41.25)**	-
Exploration and evaluation - directly expensed	**(1.89)**	(2.24)	**(2.52)**	(2.44)
Gain (loss) on sale of property and equipment	**0.31**	-	**(1.08)**	-
Share-based compensation -- non-cash portion	**(0.50)**	2.31	**0.60**	(1.09)
Deferred income tax	**40.91**	0.68	**15.59**	(2.23)
Net income (loss) per Boe	**(86.29)**	35.23	**(32.50)**	15.61

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 realized and 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 before income tax.

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

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $ except per share amounts)	**2015**	2014	Change	**2015**	2014	Change
Net cash from operating activities	**1,728**	25,392	(93)	**27,397**	48,275	(43)
Funds from operations	**2,531**	16,906	(85)	**30,354**	54,563	(44)
Per share						
Basic	**0.13**	0.98	(87)	**1.63**	3.29	(50)
Diluted	**0.13**	0.95	(86)	**1.62**	3.22	(50)
Net income (loss)	**(26,499)**	**15,367**	272	**(43,980)**	**25,641**	(272)
Per share						
Basic	**(1.37)**	0.89	253	**(2.37)**	1.55	(253)
Diluted	**(1.37)**	0.81	253	**(2.37)**	1.54	(253)

Weighted Average Shares Outstanding

	Three Months Ended December 31			Year Ended December 31		
(000's Cdn. $ except per share amounts)	**2015**	**2014**	Change	**2015**	**2014**	Change
For Net (Loss) / Income Purposes						
Basic	19,394	17,191	13	18,591	16,565	12
Diluted	19,394	17,745	9	18,591	16,959	10
For Funds from Operations Purposes						
Basic	19,394	17,191	13	18,591	16,565	12
Diluted	19,519	17,745	10	18,684	16,959	10

Funds from operations for Q4 2015 totaled $2.5 million ($0.13 per share basic and diluted) versus funds from operations in Q3 2015 of $5.9 million ($0.31 per share basic and $0.30 per share diluted) and funds from operations in Q4 2015 of $16.9 million ($0.98 per share basic and $0.95 per share diluted). Lower commodity prices and lower production in Q4 2015 reduced operating income from Q3 2015 by $1.7 million and from Q4 2014 by $8.5 million. Monetization of the Company's crude commodity risk management contracts in Q3 2015 added $1.8 million in Q3 2015 to funds from operations and $6.4 million in Q4 2014 to funds from operations versus $nil added in Q4 2015.

Funds from operations for the year ended December 31, 2015 totaled $30.4 million ($1.63 per share basic and $1.62 per share diluted) versus funds from operations in 2014 of $54.6 million ($3.29 per share basic and $3.22 per share diluted). Lower average production and lower average commodity prices reduced the operating income by $39.3 million. This was offset by the realized gain on the monetization on crude commodity contracts in Q1 and Q4 2015 of $15.1 million versus a realized gain on crude commodity contracts in 2014 of $1.3 million.

On a Boe basis, funds from operations for Q4 2015 decreased to $8.24 per Boe versus $17.91 for Q3 2015 and $38.75 for Q4 2014. For the year ended December 31, 2015 funds from operations decreased to $22.43 per Boe versus $33.22 per Boe in 2014. Lower prices and lower production resulted in lower operating income that was offset by realized gains on crude commodity risk management contracts in 2015.

The Company recorded a net loss in Q4 2015 of $26.5 million or $1.37 per share basic and diluted versus income of $15.4 million or $0.89 per share basic and $0.81 per share diluted in Q4 2014. During the current quarter, the Company's operating income dropped by $8.5 million or 64% from Q4 2014 due to lower commodity prices that decreased 35% and to a 30% drop in Q4 2015 average production from Q4 2014. As a result of lower land sale prices and deferred drilling plans, the Company recognized an impairment of its exploration and evaluation assets of $844,112 and due to drastically lower commodity prices recognized an impairment of its property plant and equipment carrying value of $35.7 million. Offsetting these items was an unrealized gain of $1.3 million on foreign exchange and a recovery of income taxes of $12.6 million.

As a result of the impairments recorded in Q3 and Q4 2015, the Company, for the year ended December 31, 2015, recorded a loss of $44.0 million or $2.37 per share basic and diluted versus income of $25.6 million or $1.55 per share basic and $1.54 per share diluted. Operating income for the year ended December 31, 2015 was down $39.3 million or 64% as prices declined 43% and production declined 18% versus the year ended December 31, 2014. In addition, losses on the sale of properties of $1.5 million and impairments totaling $57.8 million of exploration and evaluation assets and property, plant and equipment assets further contributed to the loss recorded in 2015. These items were offset by realized gains on crude risk management contracts of $15.1 million, a recovery of previously expensed share-based compensation of $814,287, a gain on foreign exchange of $6.7 million and the recovery of income tax previously provided of $21.3 million.

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 $1.0 million for Q4 2015 and a gain of $5.9 million for 2015. Comprehensive loss therefore for the three months ended December 31, 2015 was $25.5 million and for the year ended December 31, 2015 was $38.1 million versus comprehensive income of $16.4 for Q4 2014 and comprehensive income of $28.0 million for the year ended December 31, 2014.

Summary of Quarterly Results

	2015				2014			
(000's Cdn. $)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production (Boe)								
Total	**307,102**	329,812	349,956	366,349	436,245	445,997	390,583	369,746
Per day	**3,338**	3,585	3,846	4,071	4,742	4,848	4,292	4,108
Oil and gas revenue	**11,529**	13,382	16,305	13,866	25,283	33,322	30,902	27,606
Funds from operations	**2,531**	5,906	6,159	15,760	16,906	14,995	11,610	11,053
Per share - basic ($)	**0.13**	0.31	0.34	0.88	0.98	0.89	0.72	0.69
- diluted ($)	**0.13**	0.30	0.34	0.87	0.95	0.88	0.71	0.69
Net income (loss)	**(26,499)**	(13,586)	(3,429)	(466)	15,367	9,622	(376)	1,028
Per share - basic ($)	**(1.37)**	(0.71)	(0.19)	(0.03)	0.89	0.57	(0.02)	0.06
- diluted ($)	**(1.37)**	(0.71)	(0.19)	(0.03)	0.81	0.57	(0.02)	0.06
Total assets	**164,133**	207,409	226,773	230,571	236,424	223,262	211,996	202,146
Total debt (1)	**53,816**	52,339	56,635	57,229	65,198	81,230	84,416	74,294
Shares outstanding	**19,423**	19,376	17,969	17,897	17,877	16,974	16,074	16,090

(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 changes in the posted differentials, the timing of drilling and completions particularly in the US and in Alberta at Evi, property impairments, the rationalization of properties and operating costs and in the past few quarters and to 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 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 increased 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 Statements of Income (Loss)

Year Ended December 31, 2015 (000's Cdn. $)	Canada	United States	**Total Company**
Revenue			
Petroleum and natural gas	31,623	23,458	**55,082**
Royalties	(4,875)	(6,626)	**(11,501)**
	26,749	16,832	**43,581**
Realized gain on risk management contracts	14,454	371	**14,825**
Unrealized loss on risk management contracts	(12,366)	-	**(12,366)**
	28,836	17,203	**46,040**
Expenses			
Operating	17,491	4,402	**21,893**
General and administrative	1,614	2,482	**4,096**
Exploration and evaluation	3,409	-	**3,409**
Exploration and evaluation impairment	2,025	-	**2,025**
Property, plant and equipment impairment	10,431	45,385	**55,816**
Depletion and depreciation	13,847	12,860	**26,707**
Share-based compensation	(691)	-	**(691)**
Loss on sale of property	1,467		**1,467**
	49,592	65,129	**114,722**
Financial items:			
Interest and other financing charges	(1,988)	4,147	**2,159**
Accretion	920	188	**1,108**
Foreign exchange gain realized	(53)	-	**(53)**
Foreign exchange gain unrealized	(6,645)	-	**(6,645)**
	(7,766)	4,335	**(3,431)**
Income (loss) before income taxes	(12,989)	(52,261)	**(65,251)**
Income taxes			
Current income tax (recovery)	-	(168)	**(168)**
Deferred income tax (recovery)	(1,635)	(19,468)	**(21,103)**
	(1,635)	(19,636)	**(21,271)**
Net income (loss)	**(11,353)**	**(32,625)**	**(43,980)**
Translation gain (loss) on foreign operations	**-**	5,854	**5,854**
Other comprehensive income (loss)	**(11,353)**	**(26,771)**	**(38,126)**

Year Ended December 31, 2014 (000's Cdn. $)	Canada	United States	**Total Company**
Revenue			
Petroleum and natural gas	66,121	50,993	**117,114**
Royalties	(10,878)	(14,439)	**(25,317)**
	55,243	36,554	**91,797**
Realized loss on risk management contracts	2,864	(1,637)	**1,227**
Unrealized loss on risk management contracts	13,471	2,183	**15,654**
	71,578	37,100	**108,678**
Expenses			
Operating	25,589	5,178	**30,767**
General and administrative	1,273	2,753	**4,026**
Exploration and evaluation	4,010	-	**4,010**
Exploration and evaluation impairment	5,199	-	**5,199**
Property, plant and equipment impairment	-	-	**-**
Depletion and depreciation	17,434	13,419	**30,853**
Share-based compensation	1,797	-	**1,797**
Gain on sale of property	-	-	**-**
	55,302	21,350	**76,652**
Financial items:			
Interest and other financing charges	(270)	3,045	**2,775**
Accretion	1,392	361	**1,753**
Foreign exchange gain realized	(76)	-	**(76)**
Foreign exchange gain unrealized	(2,694)	-	**(2,694)**
	(1,648)	3,406	**1,758**
Income (loss) before income taxes	17,924	12,344	**30,268**
Income taxes			
Current income tax	-	969	**969**
Deferred income tax	(592)	4,250	**3,658**
	(592)	5,219	**4,627**
Net income (loss)	18,516	7,125	**25,641**
Translation gain (loss) on foreign operations	**-**	2,380	**2,380**
Other comprehensive income (loss)	**18,516**	**9,505**	**28,021**

Segmented Information

For Year Ended December 31, 2015 (000's Cdn. $)	Canada	U.S	Total
Production (Boe/d)	2,399	1,308	**3,707**
Oil and gas revenue	31,623	23,459	**55,082**
Operating income	9,257	12,431	**21,688**
Funds from operations	24,013	6,341	**30,354**
Income (loss) before income taxes	(12,992)	(52,259)	**(65,251)**
Income (loss) after income taxes	(11,357)	(32,623)	**(43,980)**
Exploration and evaluation assets (as at December 31, 2015)	1,114	-	**1,114**
Property, plant and equipment (as at December 31, 2015)	90,889	62,752	**153,641**
Exploration and evaluation asset expenditures	-	-	**-**
Property, plant and equipment expenditures	12,765	7,537	**20,302**
Exploration and evaluation expenses	3,409	-	**3,409**
Proceeds on property dispositions	1,882	-	**1,882**
Property acquisitions	-	-	**-**

For Year Ended December 31, 2014 (000's Cdn. $)	Canada	U.S	Total
Production (Boe/d)	2,862	1,638	**4,500**
Oil and natural gas revenue	66,121	50,993	**117,114**
Operating income (1)	29,653	31,377	**61,030**
Funds from operations	31,589	22,974	**54,563**
Income before income taxes	17,924	12,344	**30,268**
Net income for the year	18,516	7,125	**25,641**
Exploration and evaluation assets (as at December 31, 2014)	3,639	-	**3,639**
Property, plant and equipment (as at December 31, 2014)	109,194	97,126	**206,320**
Exploration and evaluation expenditures	487		**487**
Property, plant and equipment expenditures	24,183	28,864	**53,047**
Exploration and evaluation expenses	4,010	-	**4,010**
Property dispositions	(100)	-	**(100)**
Property acquisitions	152	-	**152**

For the Three Months Ended December 31, 2015 (000's Cdn. $)	Canada	U.S	Total
Production (Boe/d)	2,168	1,170	**3,338**
Oil and gas revenue	6,595	4,933	**11,528**
Operating income	1,529	2,268	**3,797**
Funds from operations	1,776	755	**2,531**
Income (loss) before income taxes	(6,679)	(32,697)	**(39,376)**
Net income (loss) for the year	(6,140)	(20,359)	**(26,499)**
Exploration and evaluation assets (as at December 31, 2015)	1,114	-	**1,114**
Property, plant and equipment (as at December 31, 2015)	90,889	62,752	**153,641**
Property, plant and equipment expenditures	3,859	(1,160)	**2,699**
Exploration and evaluation expenditures	-	-	**-**
Exploration and evaluation expenses	581	-	**581**
Proceeds on property dispositions	26		**26**
Property acquisitions	-		**-**

For the Three Months Ended December 31, 2014 (000's Cdn. $)	Canada	U.S	Total
Production (Boe/d)	2,990	1,752	4,742
Oil and gas revenue	14,235	11,048	25,283
Operating income	5,750	6,545	12,295
Funds from operations	10,758	6,148	16,906
Income (loss) before income taxes	12,767	2,508	15,275
Income (loss) after income taxes	13,254	2,113	15,367
Exploration and evaluation assets (as at December 31, 2014)	3,639	-	3,639
Property, plant and equipment (as at December 31, 2014)	109,194	97,126	206,320
Exploration and evaluation asset expenditures	(19)	-	(19)
Property, plant and equipment expenditures	7,460	1,584	9,044
Exploration and evaluation expenses	978	-	978
Proceeds on property dispositions	-	-	-
Property acquisitions	-	-	-

(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 Princes, 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, its 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, evaluates the risk reward profile of its exploration program and the economic returns of its 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 current or long term and 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 and significant forecasted changes to production and commodity prices.

The Company's net debt to annualized funds from operations ratio at December 31, 2015 is 5.32 : 1.

The Company's net debt to equity ratio at December 31, 2015 is 0.97: 1.

These ratios are unacceptable and unsustainable and must be reduced through higher prices, lower costs or lowering debt. Equity markets may be available to reduce debt but the dilution to existing shareholders would be significant.

In order to strengthen the Company's balance sheet, the Company monetized a portion of its November 30, 2014 crude hedge book in December 2014 and the remainder in January 2015 (these transactions contributed to reduced debt by approximately $16.1 million). In Q3 2015, the Company monetized crude hedges entered into during 2015 allocating an additional $1.9 million to debt reduction. In addition, the Company reduced the dividend during 2015 (from $0.07 per share in November 2014 to $0.03 per share in February 2015 and then to $0.02 per share in May 2015) and suspended the dividend in January 2016, reduced employee bonuses for 2014 paid in 2015 and eliminated them entirely for 2015, froze salaries, reduced staff and undertook other initiatives to reduce capital, operating and general and administrative expenditures. In July 2015, the Company further reduced debt as it closed a bought deal private placement for net proceeds of $4.2 million. In addition, the Company has and continues to sell non-core properties with proceeds dedicated to debt reduction (see "Liquidity" below).

Total Debt and Debt to Annualized Funds from Operations

(000's Cdn. $)	December 31, 2015
Bank loan	52,464
Working capital deficiency (1)	1,352
Total debt	53,816
Annualized funds from operations (2)	10,123
Net debt to annualized funds flow ratio	**5.32**

(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 and for bank borrowing classified as a current liability that I is included under “bank loan”. The Company maintains sufficient unused bank credit facility to ensure any working capital deficiency can be funded.

(2) Annualized funds from operations is current quarter annualized

Total Debt Reconciliation

(000's Cdn. $)	**Year Ended December 31**
Net debt December 31, 2014	**65,198**
Funds from operations	**(30,354)**
Net proceeds from sale of shares	**(4,229)**
Additions to property, plant and equipment	**20,302**
Exploration and evaluation expenses	**3,409**
Dividends	**1,418**
Decommissioning liabilities settled	**1,587**
Proceeds on sale of properties	**(1,882)**
Foreign exchange gain on US cash held	**(419)**
Change in non-cash working capital and other items	**(1,212)**
Total debt December 31, 2015	**53,816**

Debt to Equity Ratio

(000's Cdn. $)	December 31, 2015
Shareholders' Equity	55,732
Debt to equity	**0.97**

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

The Company has not adjusted its approach to capital management during 2015.

Credit Facility

The Company's credit facility at December 31, 2015 was $60.0 million. The semi-annual review of the borrowing base, expected to be completed on or before November 30, 2015, was not completed until January 2016. The credit facility at December 31, 2015 included a $45.0 million Extendable Syndicated Credit Facility, a $10.0 million Extendable Operating Credit Facility and a $5.0 million Supplemental Credit Facility (together the "Facility"). In January 2016, the Facility was revised to $55.0 million and consisted of a $30.0 million Extendable Syndicated Credit Facility, a $10.0 million Extendable Operating Credit Facility and a $15.0 million Supplemental Credit Facility. Borrowings under the Company's Extendible Credit Facility are available in prime based loans in either Canadian or US dollars, bankers' acceptances and London InterBank Offered Rate ("LIBOR") loans.

The Supplemental Credit Facility, available by way of a single advance on the effective date, was drawn in January at $15.0 million, is required to be repaid by May 26, 2016 and bears a margin of 2% higher than the Extendable Syndicated Credit Facility. Since the Supplemental Credit Facility has a maturity date of May 26, 2016, the amount has been classified as a current liability at December 31, 2015. Proceeds from any common share equity issues (not including proceeds from the sale of flow-through shares) and from the sale of properties are required to be applied to reduce the Supplemental Credit Facility.

Interest rates on the Extendable Operating Credit Facility and on prime based loans range from Canadian or US prime plus 1.00% to 3.50%. Bankers' acceptances and LIBOR borrowings are subject to base borrowing rates plus additional stamping fees ranging from 2.00% to 4.50. The stamping fees and margins for the Supplemental Facility are at a rate of 2.00% higher than the corresponding rate for the Extendible Credit Facility. The stamping fees and margins are dependent on the debt to cash flow ratio, as defined, and as calculated based on the Company's two most recent quarter ends.

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

The 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 and to not make distributions (defined to include dividends and purchases under a normal course issuer bid).

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 and any current drawings on the Supplemental Credit Facility) to fall to below 1 : 1.

At December 31, 2015, the Company was in compliance with this and all other covenants as required under the agreement.

At December 31, 2015, debt under the Facility amounted to $52.5 million (December 31, 2014 - $60.0 million) of which $5.0 million was outstanding under the Supplemental Credit Facility. Net debt (after adjusting for working capital deficiency at December 31, 2015 was $53.8 million (December 31, 2014 - $65.2 million).

Liquidity

Over the course of the past 18 months, there has been a severe and rapid decline in the price of crude and natural gas. While crude prices have generally recovered reasonably quickly in the past, this does not appear to be the case with the current decline in crude prices. As a result of production being greater that demand, the inventory of crude, crude bi-products and natural gas, are not only increasing but are dampening and extending any sustained price recovery. Lower prices and a slower recovery has in turn resulted in reductions in the Company's borrowing base. A reduced borrowing base in combination with lower prices has recalibrated economics and has affected the ability of the Company to continue funding capital projects. Debt repayment, cutbacks and survival is the focus of most oil and gas companies these days. Arsenal has and will continue to shut-in uneconomic wells at the expense of production, cut overhead and operating costs to become more efficient, defer drilling and tie-ins until operating margins become acceptable and continue to reduce all expenditures. The Company has entered into a process to sell non-core properties to reduce debt. While these initiatives are steps in the right direction, none in and of themselves guarantee long-term survival in a continued depressed commodity market. Prices need to improve for not only Arsenal but for the industry to survive.

Going Concern

While the steps outlined above have been initiated, there is no certainty that they will be successful, or that the funds generated will be sufficient to reduce the bank debt to an amount the Company can support with its retained assets.

Uncertainties as to the Company's ability to continue as a going concern exist due to:

- A $15 million scheduled repayment of the supplemental facility on May 26, 2016. The Company does not currently have sufficient funds to repay this amount;
- There is uncertainty as to the determination of the borrowing base that will be provided by the lenders in May 2016. ;
- There is risk that the Company will not be able to comply with the financial covenant in 2016. Compliance is impacted by the undrawn debt which is at risk. In the event the Company has a covenant violation, this would represent an event of default under the credit facility which could result in all outstanding amounts being payable on demand; and
- The Company is required to expend $2.1 million in 2016 on qualifying expenditures by December 31, 2016 to satisfy the requirements of the flow-through share issuance completed in 2015.

As a result of the above matters, there is a material uncertainty as to the Company's ability to continue as a going concern.

Dividends

In January 2016, given the Company's financial position and the current low crude and natural gas prices, the Company suspended its dividend payments.

Since the inception of the dividend plan August 2013, the Company has returned $8.0 million to shareholders in the form of cash and common shares.

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	309,716	12,708
	August 4	August 14	August 28	0.020	19,332,706	386,687	319,201	67,486
	November 2	November 13	November 27	0.020	19,375,680	387,515	323,929	63,586

Share Capital

Common Shares

	Year Ended December 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	**1,364**	**4,619**	1,712	16,558
Share issue costs	**-**	**(713)**	-	(3,715)
Issued on exercise of options	**-**	**-**	101	877
Issued pursuant to share dividend program	**122**	**250**	42	358
Purchases under normal course issuer bid	**-**	**-**	(41)	(349)
Issued on vesting of Share Award Incentive Plan	**60**	**398**		
Cancelled on expiration of amalgamation exchange provision	**-**	**-**	(17)	-
Balance - end of period	**19,423**	**155,988**	17,877	151,434

In 2015, the Company issued 122,085 common shares in relation to the share dividend program.

In June, the Company issued 59,460 commons shares pursuant to the Company's Share Award Incentive Plan (see "Share Awards Incentive Plan" below).

On July 12, 2015 the Company closed a "bought deal' private placement and issued 778,460 common shares at a price of $3.15 per common share and 585,700 flow-through common shares at a price of $3.70 per flow-through common share for gross proceeds of $4.6 million.

The Company used the proceeds of the common share portion of the Offering to pay down a portion of its Supplemental Facility thereby freeing up excess cash flow to position the Company to take advantage of property dispositions by competitors in its core areas and will use the proceeds of the flow-through common shares to incur eligible Canadian Exploration Expenses on its core properties and renounce such expenses to subscribers of these shares effective for the 2015 tax year. The expenses must be incurred by December 31, 2016.

Options

(000's)	**Year Ended December 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)	**(396)**	(5)
Balance - end of period	**618**	1,014

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.

Share Awards Incentive Plan

	Year Ended December 31, 2015		Year Ended December 31, 2014	
(000's)	**Restricted**	**Performance**	**Restricted**	**Performance**
Balance - beginning of period	**127**	**115**	-	-
Awards isued	**124**	**117**	127	115
Cancelled (forfeited or expired unexerecised)	**(22)**	**(22)**	-	-
Adjustment for dividends	**1**	**1**	-	-
Adjustment for performance factor	-	**20**	-	-
Vested and converted into common shares	**(25)**	**(35)**	-	-
Vested and paid in cash	**(16)**	**(21)**	-	-
Balance - end of period	**189**	**175**	127	115

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. The Company has determined that payment under the share award incentive plan will be partially in common shares and partially in cash and has accounted for these awards as both equity settled and as liability settled and has estimated a performance payout of 1 on the performance awards.

On June 19, 2014, the Company issued 126,600 restricted awards and 114,600 performance awards to directors, officers and employees. The first vesting of the share incentive awards issued on June 19, 2015 occurred. The payout multiplier for the performance awards was calculated at 1.5 based on the Company's ranking in the 2nd quartile based on overall shareholder return versus a peer group. The Company issued a total of 59,460 common shares (valued at $328,435 - $3.42 per share) under the Share Incentive Award Plan and remitted $125,351 to Canada Revenue Agency representing the tax liability to participants on the benefit of the awards.

On June 18, 2015, the Company issued an additional 123,700 restricted awards and 117,300 performance awards to directors, officers and employees.

At December 31, 2015, the Company has 19,422,976 common shares outstanding, 617,837 options outstanding at a weighted average price of $5.70 per share of which 537,997 are exercisable at a weighted average strike price of $5.95 and 188,699 restricted share rights and 174,966 performance share rights outstanding under the Share Award Incentive Plan.

As of the date of this MD&A, the Company has 19,422,976 common shares outstanding, 506,237 options outstanding and 178,699 restricted share award and 163,299 performance share award outstanding.

Capital Expenditures

Capital expenditures for Q4 2015 to property, plant and equipment totaled $2.7 million down from $9.0 million in Q4 2014. Expenditures of $3.9 million in Canada in Q4 2015 down from $7.5 million in Q4 2014 were incurred to drill five gross (4.49 net) wells at Princes and on completions and on equipment and facilities at Princess. In the US, expenditures accrued in Q3 2015 to drill and equip wells and on production facilities at Lindahl were actually lower than expected resulting in a reduction of $1.2 million of previously accrued expenditures.

For the year ended December 31, 2015, capital expenditures totaled $20.3 million down from $53.0 million in the year ended December 31, 2014. In Canada, the Company spent $12.8 million in 2015 versus $24.1 million in 2014 and in the US, the Company spent $7.5 million in 2015 versus $28.9 million in 2014. Expenditures in Canada were on land purchases, drilling, completions and well equipment and on facilities at Provost, Evi and Princess and in the US on drilling, completions, well equipment and production facilities at Lindahl.

During 2015, the Company disposed of small working interests in various non-core areas, in Alberta. Included in the sales was a portion of an exploration and evaluation property for proceeds of $500,000, an interest in a property at Whitemud for proceeds of $178,970 and an isolated piece of property in the Provost area for proceeds of $1.2 million.

Net Wells Drilled

	Three Months Ended December 31		Year Ended December 31	
	2015	**2014**	**2015**	2014
Net wells drilled - Oil	**1.70**	3.00	**5.59**	10.77
- Gas	**1.65**	1.00	**1.79**	1
- Dry and other	**1.00**	4.00	**1.00**	6.20
Total net wells drilled	**4.35**	**8.00**	**8.38**	17.97

Expenditures

Total Company

Property, Plant and Equipment Expenditures

(000's Cdn. $)	Three Months Ended December 31 2015	Three Months Ended December 31 2014	Year Ended December 31 2015	Year Ended December 31 2014
Land	**572**	425	**822**	4,530
Drilling and completions	**434**	6,031	**12,365**	37,842
Capitalized general and administrative	**170**	253	**715**	860
Production equipment, facilities and tie-ins	**1,523**	2,309	**6,400**	9,732
Other	**(5,755)**	4,676	**(4,709)**	8,329
Total property plant and equipment additions	**(3,056)**	13,694	**15,593**	61,293
Non-cash additions	**5,755**	(4,650)	**4,709**	(8,246)
Total Property, Plant and Equipment Expenditures	**2,699**	9,044	**20,302**	53,047

Exploration and Evaluation Expenditures

(000's Cdn. $)	Three Months Ended December 31 2015	Three Months Ended December 31 2014	Year Ended December 31 2015	Year Ended December 31 2014
Land	-	-	-	207
Drilling and completions	-	(19)	-	280
Total Exploration and Evaluation Expenditures	-	(19)	-	487

Property Acquisitions

(000's Cdn. $)	Three Months Ended December 31 2015	Three Months Ended December 31 2014	Year Ended December 31 2015	Year Ended December 31 2014
Total Property Acquisitions	**-**	-	**-**	152

Property Dispositions

(000's Cdn. $)	Three Months Ended December 31 2015	Three Months Ended December 31 2014	Year Ended December 31 2015	Year Ended December 31 2014
Total Property Dispositions	**(26)**	-	**(1,882)**	(100)

Exploration and Seismic Expenses

(000's Cdn. $)	Three Months Ended December 31 2015	Three Months Ended December 31 2014	Year Ended December 31 2015	Year Ended December 31 2014
Seismic expenditures	**77**	56	**2,857**	2,683
Other	**504**	922	**552**	1,327
Total Exploration and Seismic Expenses	**581**	978	**3,409**	4,010

CANADA

Property, Plant and Equipment Expenditures

(000's Cdn. $)	Three Months Ended December 31 2015	Three Months Ended December 31 2014	Year Ended December 31 2015	Year Ended December 31 2014
Land	**572**	425	**839**	4,198
Drilling and completions	**2,216**	4,852	**6,863**	12,563
Capitalized general and administrative	**170**	253	**715**	860
Production equipment, facilities and tie-ins	**901**	1,904	**4,348**	6,479
Other	**(4,531)**	3,025	**(3,492)**	4,692
Total property plant and equipment additions	**(672)**	10,459	**9,273**	28,792
Non-cash additions	**4,531**	(2,999)	**3,492**	(4,609)
Total Property, Plant and Equipment Expenditures	**3,859**	7,460	**12,765**	24,183

Exploration and Evaluation Expenditures

(000's Cdn. $)	Three Months Ended December 31 2015	2014	Year Ended December 31 2015	2014
Land	-	-	-	207
Drilling and completions	-	(19)	-	280
Total Exploration and Evaluation Expenditures	-	(19)	-	487

Property Acquisitions

(000's Cdn. $)	Three Months Ended December 31 2015	2014	Year Ended December 31 2015	2014
Total Property Acquisitions	-	-	-	152

Property Dispositions

(000's Cdn. $)	Three Months Ended December 31 2015	2014	Year Ended December 31 2015	2014
Total Property Dispositions	**(26)**	-	**(1,882)**	(100)

Exploration and Seismic Expenses

(000's Cdn. $)	Three Months Ended December 31 2015	2014	Year Ended December 31 2015	2014
Seismic expenditures	**77**	56	**2,857**	2,683
Other	**504**	922	**552**	1,327
Total Exploration and Seismic Expenses	**581**	978	**3,409**	4,010

USA

Property, Plant and Equipment Expenditures

(000's Cdn. $)	Three Months Ended December 31 2015	2014	Year Ended December 31 2015	2014
Land	**-**	-	**(17)**	332
Drilling and completions	**(1,782)**	1,179	**5,502**	25,279
Capitalized general and administrative	**-**	-	**-**	-
Production equipment, facilities and tie-ins	**622**	405	**2,052**	3,253
Other	**(1,224)**	1,651	**(1,217)**	3,637
Total property plant and equipment additions	**(2,384)**	3,235	**6,320**	32,501
Non-cash additions	**1,224**	(1,651)	**1,217**	(3,637)
Total Property, Plant and Equipment Expenditure	**(1,160)**	1,584	**7,537**	28,864

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. $)	**Year Ended December 31, 2015**	Year Ended December 31, 2014
Total decommissioning obligations at beginning of year	**44,729**	36,321
Obligations settled	**(1,587)**	(1,987)
Obligations disposed of	**(462)**	(36)
Obligations incurred	**619**	646
Change in estimate	**(5,328)**	7,601
Foreign currency translation	**1,271**	431
Accretion expense	**1,108**	1,753
Total decommissioning obligations at end of year	**40,350**	44,729
Recorded as folows:		
Decommissioning obligations to be incurred within one year	**300**	750
Decommissioning obligations to be incurred beyond one year	**40,050**	43,979
Total decommissioning obligations at end of year	**40,350**	44,729

At a discount rate of 10%, $15.4 million ($35.5 million undiscounted) relates to Arsenal's Canadian operations and $1.4 million ($6.2 million undiscounted) ($5.0 million US) relates to Arsenal's US operations.

Commitments and Contingencies

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, office equipment and automotive equipment
- flow-through share expenditure agreements
- banking agreement
- hedging contracts

All such contractual obligations reflect market conditions at the time of contract and do not involve related parties. Obligations at December 31, 2015 with a fixed term are as follows:

(000's Cdn. $)	2016	2017	2018	2019	2020
Flow-through share committments	2,120	-	-	-	$ -
Lease of office premises	550	321	-	-	-
Computer equipment and support lease	86	-	-	-	-
Leased vehicles	70	55	14		
Other equipent leases and software licenses	165	89	4	1	-
Total	**2,991**	**465**	**18**	**1**	**-**

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, are not material to the Company's operations. Management has, however, made provision in the financial statements for the potential of such loss. Should any loss, in excess of the provision estimated 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 and dividend payments. The Company does not enter into derivative contracts for speculative purposes. At December 31, 2015, the Company had not entered into any commodity contracts covering 2016 (see "Liquidity" under "Net Debt, Liquidity and Capital Resources" section of this MD&A).

Interest Rate Risk

Interest rate risk is defined as changes to interest rates. The Company uses financial derivative instruments as part of its risk management approach to manage interest rate to guard against primarily large upward fluctuations and changes and to help stabilize funds from operations available for future development programs and dividend payments. The Company does not enter into derivative contracts for speculative purposes. At December 31, 2015, the Company had an interest rate contracts covering the period January 1, 2016 to Feb 13, 2018 (see "Liquidity" under "Net Debt, Liquidity and Capital Resources" section of this MD&A).

Liquidity Risk

Probability of loss arising from a situation where:

(1) there will not be enough cash and/or cash equivalents to meet the needs of the Company
(2) sale of illiquid assets will yield less than their fair value, or
(3) illiquid assets will not be sold at the desired time due to lack of buyers.

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 35% of the Company's 2015 production was in the United States that generated approximately 57% of the Company's 2015 cash flow from operations.

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 and US capital markets. If Canadian and US 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, 2015 and 2014. In the application of IFRS, certain accounting policies require that management make appropriate decisions with respect to the formulation of judgments, estimates and assumptions that affect the reported statement of assets, liabilities, revenues and expenses. In the preparation of financial information, these judgments, estimates and assumptions may have a significant impact on the amounts reported in the financial statements and on the financial results of the Company. Management reviews its judgments, estimates and assumption 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. 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 share price volatility; risk-free interest rate; expected dividend
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 and Changes:

The International Accounting Standards Board (the "IASB") 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.

Leases

In January 216, the IASB issued IFRS 16 Leases, which requires lessees to recognize assets and liabilities for most leases. The standard replaces ISA17 and will be effective for annual periods beginning on or after January 1, 2019.

Financial Instruments

IFRS 9 Financial Instruments is intended to replace IAS 39 Financial Instruments: recognition and Measurement and uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and also requires a single impairment method to be used, replacing the multiple rules of IAS 39. Although new hedge accounting requirements have been introduced, Arsenal does not employ hedge accounting for risk management contracts. The standard is effective for annual periods beginning on or after January 1, 2018.

Revenue

In May 2014, the IASB issued IRS 15 Revenue from Contracts with Customers which replaces IAS18 and IAS11. The standard is required to be adopted for fiscal years beginning on or after January 1, 2018.

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 in disclosure controls and procedures during the interim period commencing October 1, 2015 and ending December 31, 2015 nor for the years ended December 31, 2015 or December 31, 2014.

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 October 1, 2015 and ending December 31, 2015 nor for the year ended December 31, 2015.