HIGHLIGHTS

(000's except share and per share amounts)	Three months ended June 30,				Six months ended June 30,			
		2009		2008		2009		2008
Financial ($)								
Production revenue, net of royalties	$	3,673	$	14,209		7,443		26,360
Realized gain (loss) on derivative contracts		2,489		(2,331)		4,546		(2,411)
Unrealized gain (loss) on derivative contracts		(1,326)		(4,715)		2,407		(12,698)
Net income (loss)		(2,444)		(2,486)		996		(13,305)
Funds flow from operations		1,507		6,339		3,413		14,072
Production volumes								
Natural gas (mcf/d)		8,077		12,422		8,031		14,098
Crude oil (bbls/d)		106		179		121		229
Natural gas liquids (bbls/d)		96		107		99		116
Total (boe/d)		1,548		2,357		1,559		2,695
Sales prices								
Natural gas, including realized hedges ($/mcf)	$	7.50	$	8.94	$	7.61	$	8.19
Crude oil ($/bbl)		68.00		125.19		57.91		102.31
Natural gas liquids ($/bbl)		52.12		113.55		43.36		98.73
Total, before ($/boe)	$	47.00	$	61.67	$	46.44	$	55.81
Netbacks ($/boe)								
Price	$	47.00	$	61.67	$	46.44	$	55.81
Royalties		(2.76)		(6.29)		(4.18)		(6.98)
Transportation		(1.71)		(1.53)		(1.71)		(1.38)
Operating costs		(15.88)		(12.97)		(15.86)		(12.12)
Total	$	26.65	$	40.88	$	24.69	$	35.33
Capital expenditures ($)								
Total capital expenditures	$	209		9,522		4,976		22,126
Undeveloped land (net acres)		142,000		119,700		142,000		119,700

MANAGEMENTS DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD & A") of the financial and operating results for Sabretooth Energy Ltd. ("Sabretooth" or the "Company") should be read in conjunction with the Company's unaudited consolidated financial statements (the "Financial Statements") and related notes for the six months ended June 30, 2009 as well as with the audited consolidated financial statements (the "Annual Financial Statements") and MD&A for the year ended December 31, 2008.

Additional information relating to the Company, including its quarterly MD & A for the year is available on SEDAR at www.sedar.com.

This MD & A is dated August 11, 2009.

REORGANIZATION TRANSACTIONS

On July 30, 2009, Sabretooth completed a recapitalization which included the infusion of new equity, the appointment of a new management team and board of directors and the acquisition of a private oil and gas company ("reorganization transactions"). Also as part of the transaction Sabretooth will change its name to Cequence Energy Ltd. These transactions were approved by the shareholders of the Company at the annual and special meeting of shareholders held on July 29, 2009 and are described in more detail under the title "Subsequent Events" in the MD&A. Certain costs related to the reorganization are reflected in the period but most of the transaction costs will be recorded in the third quarter.

The following MD&A provides a discussion of the Company's financial information for the periods ended June 30, 2008 and June 30, 2009 prior to the recapitalization transactions.

BASIS OF PRESENTATION

The financial data presented below has been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). The financial information presented reflects the consolidated financial statements of Sabretooth including its 71 percent owned subsidiary, HFG Holdings. In accordance with Canadian GAAP, the consolidated statements of Sabretooth include 100% of HFG Holdings with the minority interest reflected as a 'non-controlling interest' on the balance sheet and income statement.

The reporting and the measurement currency is the Canadian dollar. For the purpose of calculating unit costs, natural gas is converted to a barrel equivalent ("boe") using six thousand cubic feet of natural gas equal to one barrel of oil unless otherwise stated. The term barrels of oil equivalents (BOE) may be misleading, particularly if used in isolation. A BOE conversion ratio for gas of 6 mcf:1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

NON-GAAP MEASUREMENTS

Within the MD & A references are made to terms commonly used in the oil and gas industry. Netback is not defined by GAAP in Canada and is referred to as a non-GAAP measure. Netbacks equal total revenue less royalties, operating costs and transportation costs. Management utilizes this measure to analyze operating performance.

Funds flow from operations is a non-GAAP term that represents net income (loss) adjusted for non-cash items including depletion, depreciation, accretion, future income taxes, stock-based compensation, unrealized hedge gains (losses), asset write-downs and gains (losses) on sale of assets and non-controlling interest and before adjustments for changes in working capital, asset retirement expenditures and interest accrued on ABCP. The Company evaluates its performance based on earnings and funds flow from operations. The Company considers funds flow from operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The Company's calculation of funds flow from operations may not be comparable to that reported by other companies. Funds flow from operations per share is calculated using the same weighted average number of shares outstanding used in the calculation of income (loss) per share.

A reconciliation of funds flow from net income is as follows:

$(000's)	Three months ended June 30, 2009	Three months ended June 30, 2008	Six months ended June 30, 2009	Six months ended June 30, 2008
Net income (loss)	$ (2,444)	$ (2,486)	$ 996	$ (13,305)
Depletion, depreciation and amortization	3,339	4,991	6,923	10,924
Accretion	39	64	79	134
Stock based compensation	134	216	328	550
Valuation allowance on investments	-	-	-	5,932
Unrealized loss(gain) on commodity contracts	1,326	4,715	(2,407)	12,698
Loan premium amortization	(17)	-	(17)	-
Future income tax recovery	(836)	(942)	(2,536)	(2,522)
Asset retirement expenditures	(10)	(219)	(17)	(339)
Non-controlling interest	(24)	-	63	-
Funds flow	$ 1,507	$ 6,339	$ 3,413	$ 14,072

FORWARD-LOOKING STATEMENTS

Certain statements contained within this MD & A constitute forward-looking statements. These statements related to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", and similar expressions. Forward-looking statements in this MD & A include, but are not limited to, statements with respect to: the potential impact of implementation of the Alberta Royalty Framework on Sabretooth's condition and projected 2009 capital investments; the Company's ability to realize its investments in MAV 2 Notes; projections with respect to growth of natural gas production; the projected impact of land access and regulatory issues; projections relating to the volatility of crude oil prices in 2009 and beyond and reasons therefore; the Company's projected capital investment levels for 2009 and the source of funding therefore; the effect of the Company's risk management program, including the impact of derivative financial instruments; the Company's defence of lawsuits; the impact of the climate change initiatives on operating costs; the impact of Western Canada pipeline constraints; projections that the Company will fully recover from its MAV 2 Notes. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur.

By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecast, projects and other forward-looking statements will not occur, which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projects of future performance or results expressed or implied by such forward-looking statements. These assumptions, risks and uncertainties include, among other things: volatility of and assumptions regarding oil and gas prices; assumptions based upon Sabretooth's current guidance; fluctuations in currency and interest rates; the Company's ability to realize its investment in MAV 2

Notes; product supply and demand; market competition; risk inherent in the Company's marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved; the Company's ability to replace and expand oil and gas reserves; the Company's ability to generate sufficient cash flow from operations to meet its current and future obligations; the Company's ability to access external sources of debt and equity capital; the timing and cost of well and pipeline constructions; the Company's ability to secure adequate product transportation; changes in royalty, tax, environmental and other laws or regulations or the interpretations of such laws or regulations; risks associated with existing and potential future lawsuits and regulatory actions made against the Company; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by Sabretooth. Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future.

Financial outlook information contained in this MD & A about prospective results of operations, financial position or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action, based on management's assessment of the relevant information currently available. Readers are cautioned that such financial outlook information contained in this MD & A should not be used for purposes other than for which it is disclosed herein.

Although Sabretooth believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectation will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this MD & A are made as of the date of this MD & A, and except as required by law Sabretooth does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this MD & A are expressly qualified by this cautionary statement.

RESULTS OF OPERATIONS

NET INCOME AND FUNDS FLOW

The Company incurred a net loss of $2,444 for the second quarter of 2009 compared to the net loss of $2,486 for the same quarter in 2008. The loss in 2009 is primarily attributable to low natural gas prices and higher operating costs. The loss in the second quarter of 2008 was a result of total realized and unrealized losses on derivative commodity contracts of $7,046 in the period. Funds flow from operations was $1,507 for the second quarter of 2009 compared to $6,339 in 2008. The decrease in funds flow is due to a 35 percent decrease in production volumes and a 24 percent decrease in sales prices after realized hedging gains and losses.

	Three months ended June 30,				Six months ended June 30,			
$(000's)		**2009**		**2008**		**2009**		**2008**
Revenue, net of royalties	$	3,673	$	14,209	$	7,443	$	26,360
Funds flow from operations	$	1,507	4	6,339	$	3,413	$	14,072
Net income (loss)	$	(2,444)	$	(2,486)	$	996	$	(13,305)

REVENUE

Total revenue was $6,547 in the second quarter of 2009 compared to $13,228 for the comparable period in 2008. The decrease in revenue is attributable to the 35 percent decrease in production and a 24 percent decrease in realized sales prices. For the six month period ended June 30, 2009 total revenue decreased 52 percent to $13,174 from $27,371 in the prior period. The decrease in natural gas revenue for the six month period is a result of a 43 percent decrease in production volumes and a 17 percent decrease in sales price.

$(000’s)	Three months ended June 30, 2009	2008	Six months ended June 30, 2009	2008
Natural gas	$ 2,962	$ 12,407	6,571	23,433
Oil	647	2,042	1,278	4,261
Natural gas liquids	449	1,110	779	2,088
Realized gains (losses) on commodity contracts	2,489	(2,331)	4,546	(2,411)
Total Revenue	$ 6,547	$ 13,228	13,174	27,371

PRICING

Benchmark natural gas and crude oil prices decreased significantly from the first half of 2008. Sabretooth realized natural gas price before the effects of realized gains on commodity contracts was $4.07 per mcf compared to $10.98 per mcf in the second quarter of 2008. For the six month period ended June 30, 2009 the average gas price before gains on commodity contracts was $4.49 per mcf compared to $9.13 per mcf. The decrease in realized natural gas prices is consistent with the decrease in industry benchmark prices. Sabretooth’s production is approximately 87 percent natural gas and fluctuations in AECO natural gas prices have a significant impact on the company.

Oil prices for the second quarter of 2009 were $68.00 per barrel down 46 percent from the same time period in 2008. For the six month period ended June 30, 2009 realized oil prices decreased 43 percent to $57.91 per boe. Realized natural gas liquids prices decreased 54 percent and 56 percent for the three and six month periods ended June 30, 2009 from the comparative periods in 2008.
The following tables details Sabretooth’s average sales prices and benchmark indices:

Average Selling Price	Three months ended June 30, 2009	2008	Six months ended June 30, 2009	2008
Natural gas ($/mcf)	$ 4.07	$ 10.98	$ 4.49	$ 9.13
Realized natural gas hedge $/mcf)	3.43	(2.07)	3.12	(0.94)
Natural gas including realized hedge gains and losses	7.50	8.91	7.61	8.19
Crude Oil (per bbl)	68.00	125.19	57.91	102.31
Natural gas liquids (per bbl)	52.12	113.55	43.36	$ 98.73
Average sales price before hedge	$ 29.13	$ 72.54	$ 30.42	$ 60.73
Average sales price including hedge	$ 47.00	$ 61.67	$ 46.44	$ 55.81

Benchmark Pricing	Three months ended June 30, 2009	2008	Six months ended June 30, 2009	2008
AECO natural gas – monthly index (CDN$/Mcf)	3.47	8.83	4.40	8.24
AECO natural gas – daily index (CDN$/Mcf)	3.27	9.67	3.81	8.62
WTI crude oil (US$/bbl)	59.62	123.95	51.35	110.91
Edmonton par price (CDN$/bbl)	65.93	126.38	57.81	112.30
US$/CDN$ exchange rate	0.86	0.99	0.83	0.99

COMMODITY PRICE MANAGEMENT

Sabretooth has a commodity price risk management program and will enter into derivative commodity contracts to protect future cash flows or planned capital expenditures. The company has a natural gas contract in place until the end of March 2010 for the sale of 6,000 gj per day of natural gas for a price of $7.85 per gj. The fair value of derivative commodity contracts at the end of June is $5,455 compared to $3,034 in 2008. Total gains for the three and six month periods ended June 30, 2009 was $1,163 and $6,953 compared to losses of $7,046 and $15,109 for the three and six month periods ended June 30, 2008.

	Three months ended June 30,		**Six months ended June 30,**	
Benchmark Pricing	**2009**	**2008**	**2009**	**2008**
Realized gain (loss) on commodity contracts	2,489	(2,331)	4,546	(2,411)
Unrealized gain (loss) on commodity contracts	(1,326)	(4,715)	2,407	(12,698)
Total	1,163	(7,046)	6,953	(15,109)

PRODUCTION

Production for the three months ended June 30, 2009 production averaged 1,548 boe/d compared to production of 2,357 boe/d in the second quarter of 2008. The decrease of 809 boe/d is primarily due to the sale of the West Central and Fireweed properties in July 2008 and the normal production decline on existing properties. Additional production to offset declines has not been added in 2009 as drilling activity has been restricted in response to low natural gas prices.

Average production volumes for the three and six month periods ended June 30, 2009 and 2008 are outlined below:

	Three months ended June 30,			
	2009[(1)]		**2008[(1)]**	
	Total	**Per Day**	**Total**	**Per Day**
Natural Gas (mcf)	726,935	8,077	1,130,435	12,422
Crude Oil (bbls)	9,514	106	16,313	179
NGLs (boe)	8,621	96	9,771	107
Total (boe)	139,291	1,548	214,502	2,357

	Six months ended June 30,			
	2009 [(1)]		**2008[(1)]**	
	Total	**Per Day**	**Total**	**Per Day**
Natural Gas (mcf)	1,461,724	8,031	2,565,809	14,098
Crude Oil (bbls)	22,071	121	41,645	229
NGLs (boe)	17,968	99	21,154	116
Total (boe)	283,660	1,559	490,461	2,695

(1) Includes royalty volumes

ROYALTY EXPENSE

Royalty expense in the second quarter of 2009 was $385 or 9 percent of revenue compared to $1,350 or 10 percent of revenue in the second quarter of 2008. For the six month period ended June 30, 2009 royalties as a percentage of revenue were 14 percent compared to 13 percent in the comparative period in 2008. On a per barrel basis royalties decreased in both the three and six month periods due to a decline in average sales prices. Royalty rates are based on government market reference prices and increase as a percentage when commodity prices increase.

$(000's)		Three months ended June 30, 2009		2008		Six months ended June 30, 2009		2008
Royalties ($)	$	385	$	1,350	$	1,185	$	3,422
As a % of sales		9%		10%		14%		13%
Per Unit of Production ($/boe)	$	2.76	$	6.29	$	4.18	$	6.98

TRANSPORTATION EXPENSE

In the second quarter of 2009 transportation costs per boe increased to $1.71 per boe or 12 percent from the comparative period. Transportation costs for the six months ended June 30, 2009 were $1.71 per boe an increase of 25 percent from the comparative period in 2008. The increase per boe is attributable to the rising transportation costs for the company's assets in British Columbia.

$(000's)		Three months ended June 30, 2009		2008		Six months ended June 30, 2009		2008
Transportation ($)	$	238	$	329	$	485	$	675
Per Unit of Production ($/boe)	$	1.71	$	1.53	$	1.71	$	1.38

OPERATING COSTS

Operating costs during the second quarter of 2009 were $2,212 or $15.88 per boe compared to $2,782 or $12.97 per boe for the same time period in 2008. From the six month period ended June 30, 2009 operating costs increased to $15.86 per boe from $12.12 in the prior period. The increase in operating costs per boe in both the three and six month periods were a result of decreased production while fixed costs remained constant.

Operating costs for the first quarters of 2009 and 2008 are summarized below:

$(000's)		Three months ended June 30, 2009		2008		Six months ended June 30, 2009		2008
Operating Costs ($)	$	2,212	$	2,782	$	4,498	$	5,945
Per Unit of Production ($/boe)	$	15.88	$	12.97	$	15.86	$	12.12

OPERATING NETBACKS

Sabretooth's netback for the second quarter of 2009 decreased to $26.65 per boe in 2009 from $40.88 in 2008. In comparison to 2008, the decrease in the netback in both the three and six month periods is primarily due to the lower average selling prices, higher operating and transportation costs. Offsetting the decrease in netbacks were lower royalties, and the realized gain on hedge contracts.

		Three months ended June 30, 2009		2008		Six months ended June 30, 2009		2008
Production revenue, including realized hedge gains (losses)	$	47.00	$	61.67	$	46.44	$	55.81
Royalty expense		(2.76)		(6.29)		(4.18)		(6.98)
Transportation Expense		(1.71)		(1.53)		(1.71)		(1.38)
Operating Costs		(15.88)		(12.97)		(15.86)		(12.12)
Netback, $/boe	$	26.65	$	40.88	$	24.69	$	35.33

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative ('G&A") expenses for the three months ended June 30, 2009 were $1,884, compared to $1,452 for 2008. For the six month period ended June 30, 2009 G&A expenses increased to $2,797 from $2,114 in 2008. On a per boe basis G&A was $13.52 in the second quarter of 2009 compared to $6.77 in 2008. The increase per boe is primarily attributable to decreased production from the prior period. In addition, $254 relates to the reorganization transactions completed in July 2009 and a $238 allowance for doubtful accounts was included in G&A in the second quarter. For the three and six months ended June 30, 2009 Sabretooth capitalized $459 and $942 of G&A expenses related to exploration and development.

	Three months ended June 30,		Six months ended June 30,	
$(000's)	**2009**	**2008**	**2009**	**2008**
G&A Expenses ($)	$ 1,884	$ 1,452	$ 2,797	$ 2,114
Per Unit of Production ($/boe)	$ 13.52	$ 6.77	$ 9.86	$ 4.31

INTEREST EXPENSE

Interest expense for the three months ended June 30, 2009 were $294 compared to $757 for the comparative period. For the six months ended June 30, 2009 interest expense was $762 compared to $1,501 in 2008. The decrease in interest expense in both periods is attributable to the decrease in bank debt and lower interest rates.

	Three months ended June 30,		Six months ended June 30,	
$(000's)	**2009**	**2008**	**2009**	**2008**
Interest Expense ($)	$ 294	$ 757	$ 762	$ 1,501
Per Unit of Production ($/boe)	$ 2.11	$ 3.53	$ 2.68	$ 3.06

DEPLETION, DEPRECIATION AND AMORTIZATION ("DD&A")

DD&A expense for the three months ended June 30, 2009 decreased to $3,339 or $23.97 per boe compared to $4,991 or $23.27 per boe in 2008. For the six month period ended June 30, 2009 DD&A per boe was $6,923 or $24.41 per boe compared to $10,924 or $22.27 per boe in 2008. Total DD&A decreased as a result of lower production in the period.

The depletion rate is impacted by the costs to acquire, explore and develop reserves of crude oil and natural gas, known as finding, development and acquisition costs. In the early stages of exploration, capital costs may be recognized before proven reserves are fully booked leading to higher initial depletion rates. In addition higher depletion rates also result as new production often receives lower reserves assignments under National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") due to the naturally unpredictable nature of newer production.

ASSET RETIREMENT OBLIGATIONS

Total asset retirement obligations at June 30, 2009 were $2,625 compared to $2,515 at December 31, 2008. During the three and six month periods ended June 30, 2009, the company recorded accretion expense of $39 and $79, respectively.

STOCK-BASED COMPENSATION

The Company recognizes stock-based compensation expense for all stock options granted. For the three months ended June 30, 2009, Sabretooth recorded $134 (2008 - $216) in stock based compensation expense, with a corresponding increase to contributed surplus, for stock options granted. For the six month period ended June 30, 2009 stock-based compensation was $329 compared to $550 in 2008.

COMMON SHARES OUTSTANDING

On January 7, 2009, the Company repurchased 200,000 common shares of the Company under its normal course issuer bid ("NCIB") for $85 or $0.42 per share. The stated value of the shares was debited to share capital, with the excess of stated value over the cost of the re-acquisition of $913 credited to contributed surplus.

No additional options were granted in 2009.

CAPITAL EXPENDITURES

	Six months ended June 30,	
$(000's)	**2009**	**2008**
Land acquisition costs	$ 27	$ 5,272
Geological & geophysical	-	288
Drilling, completions & workovers	3,319	12,681
Tangible equipment	688	2,539
Capitalized overhead	942	1,309
Office furniture & equipment	-	37
Total capital expenditures	$ 4,976	$ 22,126

Capital expenditures for the six months ended June 30, 2009 include $942 of capitalized overhead and $4,007 of drilling work and equipment related to the completion of a horizontal well at Red Creek and a re-entry at Sinclair. Capital expenditures for the second quarter amounted to $209 with no significant individual expenditures.

INCOME TAXES

The Company has non-capital loss carry-forwards, investment tax credits and Scientific Research and Experimental Development ("SRED") expenses available to reduce future years' income for tax purposes. The SRED expenses of approximately $22,704 available for carry-forward do not expire.

In addition, the Company on a consolidated basis has UCC pools of approximately $20,000; COGPE pools of approximately $17,000; CEE pools of approximately $34,000; CDE pools of approximately $4,000 and share issue costs of approximately $2,700 which can be used to reduce future taxable income. At June 30, 2009 a future income tax asset of $3,139 has been recognized as a future income tax asset as the Company believes, based on estimated cash flows, it is more likely than not to be realized.

The non-capital losses and investment tax credits expire as follows:

Year of expiry	Non-capital losses $(000's)	Investment tax credits $(000's)
2009	$ 8,224	$ -
2010	-	930
2011	-	1,280
2012	-	672
2013	6,812	761
2014	2,791	338
2025	8,957	-
2026	18	-
2027	2,822	-
2028	351	-
2029	565	-
	$ 30,540	$ 3,981

LIQUIDITY AND CAPITAL RESOURCES

The Company has established two credit facilities with a Canadian chartered bank. Credit facility A is a $40,000 revolving operating demand loan by way of prime rate based loans, Banker's Acceptances and letters of credit/guarantee, which bears interest at the bank prime rate plus 0.25 percent to 2.5 percent on a sliding scale, depending on the Company's debt to cash flow ratio (ranging from being less than 1.0:1.0 to greater than or equal to 3:1). Credit facility B is a $5,000 non-revolving acquisition/development demand loan, which bears interest at the bank prime rate plus 0.75 percent to 3.0 percent on the same sliding scale as credit facility A. Both credit facilities are subject to periodic review by the bank and are secured by a general assignment of book debts and a $165,000 demand debenture with a first floating charge over all assets of the Company. The Company is required to meet certain financial based covenants under the terms of this facility. The Company is also required to hedge no more than 70% of its production under the lending agreement. As at June 30, 2009, the Company has drawn $29,740 on Facility A and $ Nil on Facility B. The next scheduled review is to take place in October 2009.

On March 31, 2009, the Company's bank provided the Company with an additional credit facility to provide liquidity in respect to the MAV 2 Notes (note 3). The credit facility is $18,120 revolving credit facility with an initial maturity date of March 30, 2012 with an option to extend the term to seven years on a year by years basis if agreed to by both parties. The facility provides lending against the restructuring notes held by the company and was computed in two tranches:

Tranche A: $10,872 revolving credit facility, which represents an amount equal to approximately 45% of the face value of the restructuring notes.
Tranche B: $7,248 revolving credit facility, which represents an amount equal to approximately 30% of the face value of the restructuring notes.

Interest is payable at preferred rates. Prime rate loans are at the bank prime rate less 1% or by bankers acceptance at discounted bankers' acceptance rates plus a stamping fee of 0.65 %. The credit facility is secured by the MAV 2 Notes as well as a hypothecation/pledge of the notes and all cash proceeds the Company receives on the sale of MAV 2 Notes will reduce the available amount of the facility commencing with Tranche A. The Company is required to meet certain financial based covenants under the terms of this facility. The credit facility provides for the ability of the Company to assign to the bank the MAV 2 Notes in payment of the principal due under Tranche A only.

At June 30, 2009 the company had borrowed $18,120 using this facility. The effective interest rate for the quarter ended June 30, 2009 was 1.15%.

INVESTMENTS

The Company holds replacement long-term floating rate notes as a result of the restructuring of asset-backed commercial paper ("ABCP"). At December 31, 2008, the Company held ABCP with an original cost of $24,147 and an interest rate of 4.52%. On January 21, 2009, the Pan-Canadian Investors Committee announced the completion of the restructuring of the ABCP. The restructuring plan extends the maturity of the ABCP to provide for a maturity similar to that of the underlying assets. The transactions of the ABCP conduits supported solely by leveraged collateralized debt and a combination of synthetic and traditional securitized assets, have been pooled into the Master Asset Vehicles "MAV" 1 and 2, which are class A1 and class A2 senior long-term notes that will bear interest at floating rates and class B and C subordinated long-term notes that will bear interest at floating rates. Ineligible assets in MAV 1 and MAV 2 have been segregated, and note holders have received ineligible assets tracking notes that will track the performance of the underlying individual asset. The transactions of the ABCP conduits supported exclusively by high-risk assets and traditional assets have been pooled into MAV 3, which are long-term notes that will bear interest at floating rates.

As a result of the restructuring, the Company received MAV 2 Notes, including senior notes (Class A1 and A2) and subordinated Class B and C notes, which have not been rated by DBRS Limited. MAV 2 notes means that the Company will not finance margin calls, but will receive a reduced coupon. The Class A1 and A2 notes will pay interest and Class B and C notes will accrue interest with payments to be made only after the Class A1 and A2 notes have been fully repaid. The following are the new notes received from the restructuring:

MAV2	Class A1	$	6,717
MAV2	Class A2	$	14,149
MAV2	Class B	$	2,568
MAV2	Class C	$	725
		$	24,159

As at January 21, 2009 the carrying value of the previous notes was removed from the consolidated balance sheet and replaced with the new notes at fair value. No gain or loss on exchange was recognized because the total fair value of the MAV 2 Notes and the expected interest payments net of restructuring costs was equal to the carrying value of the ABCP investments at January 21, 2009. These new notes were then designated as held-for-trading financial assets and will be subject to mark-to-market accounting in future periods. Changes in fair value will be recorded in income as they arise.

For the six months ended June 30, 2009, the Company received $1,166 of interest on the ABCP related to the period between August 13, 2007 and December 31, 2008. The interest receivable is presented on the consolidated balance sheet as the short-term portion of investments in floating rate notes. Interest for the period January 22, 2009 to June 30, 2009 has not been accrued as a result of low current interest rates.

The valuation technique used by the Company to estimate the fair value of its investment in MAV 2 Notes at June 30, 2009 and ABCP at December 31, 2008, incorporates probability-weighted discounted cash flows considering the best available public information regarding market conditions and other factors that a market participant would consider for such investments. Probability-weighted discount rates of approximately 6.45% were used at March 31, 2009 for Class A1 and Class A2 and 11.85% for Class B subordinated notes for this estimate and an interest rate of 0.00% was used (bankers' acceptance rate less 50 basis points). Due to current bankers acceptance rates, a decrease of 50 basis points would result in negative interest. As a result, a zero coupon rate has been assumed. The assumptions used in determining the estimated fair value reflect the public statements made by the Pan-Canadian Investors Committee and the estimated new notes received, as described above, with maturities matching the maturities of the underlying assets and bearing market interest rates commensurate with the nature of the underlying assets and their associated cash flows and the credit rating and risk associated with the long-term floating rate notes. Discount rates have been estimated using Government of Canada benchmark rates plus expected credit spreads premiums for lack of liquidity, uncertainty for future payments, lack of transparency and the nature of the underlying assets. Assumptions have been made as to the long-term interest rates to be received from the long-term floating rate notes. The term of the notes is estimated to be approximately eight years which approximates the maturity of the assets backing the notes. Interest on Class A1 notes is to be accrued and paid currently, with interest on all other Classes to be accrued, but only paid after interest on higher ranking Classes is paid. The probability weighted discounted cash flows resulted in an estimated fair value of the Company's MAV 2 Notes of $13,968 at June 30, 2009 (December 31, 2008 - $13,968), a cumulative reduction of $10,179 to the original cost of the ABCP which was recorded throughout 2008 and 2007. As the estimated fair value was unchanged during the quarter, no amounts were charged to income (June 30, 2008 - $5,932). The Company has maintained its 100% allowance against the MAV 2 Class C notes in the amount of $725.

There are currently no market quotations available for the ABCP or the new MAV 2 Notes and uncertainties exists regarding the value of the assets which underlie the MAV 2 Notes, the amount and timing of cash flows, the evolution of the liquidity of the market for the new notes issued following the restructuring and the evolution of the prevailing economy could give rise to a further change in the value of the Company's investment in the MAV 2 Notes. It is reasonably possible that changes in future conditions in the near term could require a material change in the recognized amount. The reduction from the face value could range from $13,252 to $9,487 based on alternative reasonable assumptions, although given the nature of the information available, the amount ultimately recovered could vary outside these ranges. A one percent increase in the discount rate will decrease the fair value of the MAV by approximately $760.

CONTRACTUAL OBLIGATIONS

Sabretooth is committed to various contractual obligations and commitments in the normal course of operations and financing activities. The Company has a lease agreement for office premises with minimum annual net lease payments, exclusive of operating costs, as follows:

2009	$	84
2010		170
2011		143
2012		107
Total	$	504

Pursuant to a flow-through share offering of the Company's 71% owned subsidiary HFG Holdings Inc. ("HFG"), HFG is committed to incur a total of $15,221 in CEE qualifying expenditures by December 31, 2009. As of June 30, 2009, the company estimates that $11,946 of the CEE commitment remains outstanding.

OUTSTANDING SHARE DATA

As of the date of this MD&A, Sabretooth had the following securities outstanding: 126,163,114 common voting shares; 19,941,455 rights to purchase common shares; 20,800,000 warrants and 65,000 stock options.

SUBSEQUENT EVENTS

On July 30, 2009, Cequence Energy Ltd. (formerly Sabretooth Energy Ltd.) (the "Company") closed the previously announced recapitalization transactions which provided for a private placement, the appointment of a new management team and board of directors and the acquisition of a private oil and gas company ("reorganization transactions"). These transactions were approved by the shareholders of the Company at the annual and special meeting of shareholders held on July 29, 2009.

In connection with the closing of the reorganization transactions, the new management, directors, certain employees and consultants of the Company and their permitted assigns (as well as a former officer of the Company) purchased approximately 25.5 million common shares of the Company at a price of $0.37 per share for aggregate subscription proceeds of approximately $9.44 million (the "Private Placement"). In addition, existing shareholders of Sabretooth were granted rights to acquire a maximum of 27,027,027 common shares at a price of $0.37 and are exercisable until August 14, 2009. The Company also acquired all the shares of a private oil and gas company owned by certain members of the new management team in exchange for the issuance of an aggregate of approximately 1.5 million common shares of the Company at a price of $0.37 per share.

As part of the completion of the Transactions, the new management and certain directors were issued 20,800,000 performance warrants convertible into non-voting shares of the Company. Each performance warrant has an exercise price of $0.47 per non-voting share and will be exercisable upon reaching certain common share trading price thresholds. As part of the reorganization all but 65 of the current options outstanding at June 30, 2009 were forfeited.

At the Meeting, shareholders also approved the change of the Company's name to "Cequence Energy Ltd." and the consolidation of the Company's common shares on a four-for-one basis. The Company has filed articles of amendment to give effect to the name change and, as a result, the Company now carries on business as "Cequence Energy Ltd.".

On May 27, 2009 the Company entered into an agreement to sell on a private placement basis 53.6 million subscription receipts at a price of $0.86 per subscription receipt for total proceeds of $46.1 million. The subscription receipts are convertible to Cequence common shares without further consideration upon shareholder approval of the reorganization transactions and regulatory approval. Upon closing of the Transactions, the Company's subscription receipts previously issued on June 18, 2009 were converted, for no additional consideration and without further action, into common shares of the Company. Holders of the subscription receipts will receive one common share of the Company for each subscription receipt held.

At June 30, 2009, $315 is included in prepaid expenses related to share issue costs associated with the transaction. These amounts will be transferred to share issue costs in the third quarter. In the second quarter $254 in included in general and administrative expenses related to costs associated with the reorganization transactions. Substantially all of the Company's outstanding stock options were cancelled as part of the transaction.

QUARTERLY INFORMATION

FINANCIAL ($ thousands except per share data)	2009		2008				2007	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Production Revenues (including gains (losses) on financial commodity contract)	6,548	$6,627	$10,562	$23,910	$8,513	$6,160	$12,888	$8,547
Royalties	385	800	894	1,437	1,350	2,072	2,246	1,454
Operating expenses	2,212	2,286	2,831	3,995	2,782	3,163	3,647	1,955
Transportation expenses	238	247	342	319	329	346	521	244
Net income (loss)	(2,444)	3,440	(987)	6,113	(2,486)	(10,819)	217	(497)
Per share - basic	(0.06)	0.09	(0.03)	0.16	(0.06)	(0.28)	0.01	(0.02)
Per share - diluted	(0.06)	0.09	(0.03)	0.16	(0.06)	(0.28)	0.01	(0.02)
Funds flow	1,507	1,906	1,278	4,900	6,558	7,853	5,985	3,875
Per share - basic	0.04	0.05	0.03	0.13	0.17	0.20	0.15	0.14
Per share - diluted	0.04	0.05	0.03	0.13	0.17	0.20	0.15	0.13
Capital expenditures, net	209	4,767	6,024	(11,983)	9,522	12,604	12,013	4,112
Acquisition expenditures, net	-	-	-	-	-	-		24,752
Total expenditures	$179	$4,767	$6,024	$(11,983)	$9,522	$12,064	$12,013	$28,864

	2009		2008				2007	
OPERATIONS	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
Production Volumes								
Natural gas (mcf/day)	8,077	8,164	9,480	10,918	12,422	15,773	17,303	10,813
Oil (bbl/day)	106	140	186	197	179	278	325	165
NGLs (bbl/day)	96	104	122	107	107	125	171	36
Total boe/day	1,548	1,602	1,887	2,123	2,357	3,032	3,380	2,003
Average selling price								
Natural gas ($per mcf)	$7.50	$7.71	$7.34	$8.33	$8.91	$7.63	$6.84	$7.12
Oil ($per bbl)	68.00	50.26	$53.55	$112.39	$125.19	$87.57	76.55	80.61
NGLs ($per bbl)	52.12	35.28	$67.98	$112.16	$113.55	$86.02	75.81	75.89
Combined ($per boe)	$47.00	$45.97	$46.52	$58.88	$61.67	$51.25	$46.21	$46.91
Royalties ($per boe)	2.76	5.55	5.15	7.36	6.29	7.51	7.22	7.89
Operation expense ($per boe)	15.88	15.86	16.30	20.45	12.97	11.46	11.73	10.61
Transportation ($per boe)	1.71	1.71	1.97	1.63	1.53	1.25	1.68	1.32
Netback ($per boe)	$26.65	$22.85	$23.10	$29.44	$40.88	$31.03	$25.58	$27.09

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company has the following financial instruments:

Cash and cash equivalents are designated as held-for-trading instruments and are measured at fair value. Long-term investments are designated as held-for-trading and are measured at fair value with changes in fair value recognized in earnings. Accounts receivable and deposits are designated as loans and receivables and are measured at amortized cost. Accounts payable and accrued liabilities, bank indebtedness and long-term debt are designated as other financial liabilities and are measured at amortized cost. All risk management assets and liabilities, including commodity contracts, are derivative financial instruments and are classified as held-for-trading.

The Company uses various types of derivative financial instruments to manage risks associated with natural gas price fluctuations. These instruments are not used for trading or speculative purposes. Proceeds and costs realized from holding the related contracts are recognized at the time each transaction under a contract is settled. For the unrealized portion of such contracts, the Company utilizes the fair value method of accounting. The fair value is based on an estimate of the amounts that would have been paid to or received from counter parties to settle these instruments given future market prices and other relevant factors. The method requires the fair value of the derivative financial instruments to be recorded at each balance sheet date with unrealized gains or losses on those contracts recorded through net earnings. Transaction costs, if any, are expensed when incurred in relation to the acquisition of a derivative.

The nature of these financial instruments and the Company's operations expose the Company to market risk, credit risk and liquidity risk. The Company manages its exposure to these risks by operating in a manner that minimizes these risks. Senior management employs risk management strategies and policies to ensure that any exposure to risk is in compliance with the Company's business objectives and risk tolerance levels. The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework. The Board has established policies in setting risk limits and controls and monitors these risks in relation to market conditions.

A) MARKET RISK

Market risk is the risk that changes in market prices, such as foreign exchange rates, commodity prices, and interest rates will affect the Company's net earnings or the value of financial instruments. These risks are generally outside the control of the Company. The objective of the Company is to mitigate market risk exposures within acceptable limits, while maximizing returns.

Commodity price risk

The nature of the Company's operations results in exposure to fluctuations in commodity prices. Management continuously monitors commodity prices and initiates instruments to manage exposure to these risks when it deems appropriate. As a means of managing commodity price volatility, the Company enters into various derivative financial instrument agreements and physical contracts. Collars ensure that the commodity prices realized will fall into a contracted range for a contracted sale volume based on the monthly index price. Monthly gains and losses are determined based on the differential between the AECO daily index and the AECO monthly index when the monthly index price falls in between the floor and the ceiling. Derivative financial instruments are marked-to-market and are recorded on the consolidated balance sheet as either an asset or liability with the change in fair value recognized in net earnings.

The following information presents all positions for the derivative financial instruments outstanding as at June 30, 2009:

Term	Volume	Price	Basis
April 1, 2009 to March 31, 2010	6,000 GJ/day	$7.85	AECO

Realized gains totalling $2,489 for the second quarter and $4,546 year to date was recognized from commodity contracts compared to realized losses of ($2,331) and ($2,411) for the comparative periods in 2008. The fair value of the commodity contracts outstanding at June 30, 2009 was an asset of $5,455 (December 31, 2008 - $3,034). The company recorded unrealized loss on derivative commodity contracts of $1,326 in the second quarter (2008 - loss of $4, 715) and an unrealized gain of $2,407 in the six months ended June 30, 2009 (2008 - loss of $12,698).

Foreign exchange risk
The Company is exposed to foreign currency fluctuations as crude oil and natural gas prices are referenced to U.S. dollar denominated prices. As at June 30, 2009 the Company had no forward, foreign exchange contracts in place, nor any significant working capital items denominated in foreign currencies.

Interest rate risk
The Company is exposed to interest rate risk to the extent that changes in market interest rates impact its borrowings under the floating rate credit facilities (note 5 and 6). The floating rate debt is subject to interest rate cash flow risk, as the required cash flows to service the debt will fluctuate as a result of changes in market rates. The Company has no interest rate swaps or financial contracts in place as at or during the three months ended June 30, 2009.

Based on debt outstanding at June 30, 2009, a 1% change in interest rate with all other variables held constant, after tax net earnings for the quarter would have changed by $85.

B) CREDIT RISK
The majority of the Company's accounts receivable are due from joint venture partners in the oil and gas industry and from purchasers of the Company's petroleum and natural gas production and are subject to the same industry factors such as commodity price fluctuations and escalating costs. The Company generally extends unsecured credit to these customers and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions. Management believes the risk is mitigated by the size and reputation of the companies to which they extend credit. The Company has not experienced any credit loss in the collection of accounts receivable to date.

The Company also has credit risk related to its long-term investment in commercial paper further described in Note 3. There is currently no market quotations for the long term investment and uncertainties exist regarding the values of the assets which underlie the MAV 2 notes.

Receivables from petroleum and natural gas marketers are normally collected on the twenty-fifth day of the month following production. Receivables related to the sale of the Company's petroleum and natural gas production are from major marketing companies. The Company historically has not experienced any collection issues with its petroleum and natural gas marketers. As at June 30, 2009 the Company has approximately $1,706 of petroleum and natural gas receivables which have subsequently been collected.

Joint venture receivables are typically collected within one to three months of the joint venture billing being issued to the partners. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to expenditure and issuing cash calls on large capital projects to its partners on capital projects before they commence. The Company reviews the financial status of joint venture partners before partner approval is obtained. The Company does not consider any of the joint venture receivables to be significantly past due or uncollectable.

Cash and cash equivalents consist of bank balances. The Company manages the credit exposure of cash by selecting financial institutions with high credit ratings and monitors all short-term deposits to ensure an adequate return.

As at June 30, 2009, the maximum exposure to credit risk was $35,827 (2008 - $40,889) being the carrying value of its cash and cash equivalents, accounts receivable, commodity contracts, and investment in commercial paper. Credit risk on the investment in commercial paper is partly mitigated by a put option embedded in the long term debt agreement. The option repay the outstanding loan amount under Tranche A at the maturity date in exchange for the MAV 2 notes, a maximum of $10,872.

C) LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they are due. The Company's financial liabilities consist of accounts payable and accrued liabilities and bank indebtedness and long term debt. The Company's approach to managing liquidity is to ensure that it will have sufficient liquidity to meet its liabilities when they are due. The nature of the oil and gas industry is capital intensive. As a result, the Company prepares annual capital expenditure budgets and utilizes authorizations for expenditures for projects to manage capital expenditures. Refer to note 16 for disclosure related to the management of capital.

The Company's ongoing liquidity is impacted by various external events and conditions, including commodity price fluctuations and the global economic downturn.

D) FAIR VALUE OF FINANCIAL INSTRUMENTS

The Company's cash and cash equivalents, accounts receivable, deposits, bank indebtedness, accounts payable and accrued liabilities and long-term debt approximate their carrying values due to their short terms to maturity and the floating interest rate on the Company's debt.

The fair value of derivative contracts is determined by discounting the difference between the contracted price and published forward price curves as at the balance sheet date, using the remaining contracted petroleum and natural gas volumes.

The fair value of the Company's investment in commercial paper, as disclosed in Note 3 and Note 6 to the financial statements, is determined by probability-weighted discounted cash flows considering the best available public information regarding market conditions and other factors that a market participant would consider for such investments.

DISCLOSURE CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Chief Executive Officer and Chief Financial Officer, after evaluating the effectiveness of the Company's disclosure controls and procedures as of June 30, 2009, have concluded that the Company's disclosure controls and procedures were adequate and effective to ensure that material information relating to the Company would have been made known to them.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Chief Executive Officer and Chief Financial Officer are also responsible for designing internal controls over financial reporting or causing them to be designed under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. The COSO framework provides the basis for managements design of internal controls over financial reporting. As at June 30, 2009, the Company's Chief Executive Officer and Chief Financial Officer have evaluated or caused to be evaluated under their supervision the effectiveness of the Company's internal controls over financial reporting and have concluded that there are several material weaknesses with regards to lack of segregation of duties and lack of financial reporting expertise.

The relatively small size of the Company makes the identification and authorization process relatively efficient; however, during the evaluation of the design of internal controls over financial reporting it was noted that, due to the limited number of staff at Sabretooth, it is not feasible to achieve complete segregation of incompatible duties nor does the Company have a sufficient number of finance personnel with all the technical accounting knowledge required to address all complex and non-routine accounting transactions that may arise, which may lead to the possibility of inaccuracies in financial reporting. The Company has employed accounting staff to ensure financial reporting and internal controls over financial reporting have been designed which provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements. In the third quarter of 2009 the Company intends to develop a remediation plan to address these weaknesses.

The Company is required to disclose herein any change in the Company's internal control over financial reporting that occurred during the period from January 1, 2009 to June 30, 2009 that has materially affected, or is likely to materially affect, the Company's internal control over financial reporting. No material changes in the Company's internal control over financial reporting were identified during such period, which has materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting. Management and the Board work to mitigate the risk of a material misstatement in financial reporting; however, a 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 and it should not be expected that the disclosure and internal control procedures will prevent all errors or fraud.

CHANGES IN ACCOUNTING POLICIES AND FUTURE ACCOUNTING PRONOUNCEMENTS

I) GOODWILL AND INTANGIBLE ASSETS

Effective January 1, 2009, the Company adopted CICA Section 3064, "Goodwill and Intangible Assets", which has replaced Handbook Section 3062. This new guidance reinforces a principles-based approach to the recognition of costs as assets in accordance with the definition of an asset and the criteria for asset recognition under Handbook Section 1000, "Financial Statement Concepts". Section 3064 clarifies the application of the concept of matching revenues and expenses in Section 1000 to eliminate the current practice of recognizing as assets items that do not meet the definition and recognition criteria. Under this new guidance, fewer items meet the criteria for capitalization. The implementation of this section had no impact on the Company's financial statements.

II) CREDIT RISK AND THE FAIR VALUE OF FINANCIAL ASSETS AND FINANCIAL LIABILITIES

Effective January 1, 2009, the Company adopted the Emerging Issues Committee ("EIC") abstract 173, "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities" which provides further information on the determination of the fair value of financial assets and financial liabilities under Section 3855, entitled "Financial Instruments - Recognition and Measurement". EIC 173 is to be applied retrospectively without restatement of prior periods to all financial assets and liabilities measured at fair value in interim and annual financial statements for periods ending on or after the date of issuance of this abstract. The implementation of this section resulted in no change to the Company financial statements.

FUTURE ACCOUNTING PRONOUNCEMENTS

In addition, the Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have an impact on the Company:

I) BUSINESS COMBINATIONS

In January 2009, the CICA issued Section 1582, "Business Combinations", which replaces former guidance on business combinations. The new Section expands the definition of a business subject to an acquisition and establishes significant new guidance on the measurement of consideration given, and the recognition and measurement of assets acquired and liabilities assumed in a business combination. The new Section requires that all business acquisitions be measured at the full fair value of the acquired entity at the acquisition date even if the business combination is achieved in stages, or if less than 100 percent of the equity interest in the acquiree is owned at the acquisition date.

Currently, the purchase price used in business combinations is based on the average of the fair value of shares issued as consideration a few days before and after the day the terms and conditions have been agreed to and the acquisition announced. Under the new standard, however, the purchase price used in a business combination is based on the fair value of shares exchanged at their market price at the date of the exchange. Obligations for contingent considerations and contingencies will also be recorded at fair value at the acquisition date and re-measured at fair value through net earnings each period until settled. Currently, only contingent liabilities that are resolved and payable are included in the cost to acquire the business. In addition, under the new standard, negative goodwill is required to be recognized immediately in net earnings. Currently, the requirement is to eliminate negative goodwill by deducting it from non-monetary assets in the purchase price allocation. The standard also states that acquisition-related costs, including restructuring and other direct costs, will be expensed as incurred and that restructuring charges will be expensed in the periods after the acquisition date, unless they constitute the costs associated with issuing debt or equity securities. Restructuring and other direct costs of a business combination are no longer considered part of the acquisition accounting.

This standard is equivalent to the International Financial Reporting Standard 3, "Business Combinations (January 2008)" on business combinations. This standard is applied prospectively to business combinations with acquisition dates on or after January 1, 2011. Earlier adoption is permitted. This new Section will only have an impact on the Company's consolidated financial statements for future acquisitions that will be made in periods subsequent to the date of adoption.

II) CONSOLIDATED FINANCIAL STATEMENTS AND NON-CONTROLLING INTERESTS

In January 2009, the CICA issued Handbook Section 1601, "Consolidated Financial Statements", and 1602, "Non-controlling Interests", which replaces existing guidance. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination.

Section 1602 applies to the accounting for non-controlling interests and transactions with non-controlling interest holders in consolidated financial statements. The new Sections require that, for each business combination, the acquirer measure any non-controlling interest in the acquiree either at fair value or at the non-controlling interest's proportionate share of the acquiree's identifiable net assets. The new Sections also require non-controlling interest to be presented as a separate component of shareholders' equity. Under Section 1602, non-controlling interest in income is not deducted in arriving at consolidated net income or other comprehensive income. Rather, net income and each component of other comprehensive income are allocated to the controlling and non-controlling interests based on relative ownership interests.

These two Sections are the equivalent to the corresponding provisions of International Accounting Standard 27, "Consolidated and Separate Financial Statements (January 2008)". These Sections apply to interim and annual consolidated financial statements relating to fiscal years beginning on or after January 1, 2011, and should be adopted concurrently with Section 1582. Earlier adoption is permitted. The Company is currently evaluating the impact of adopting this standard on its consolidated financial statements.

III) INTERNATIONAL FINANCIAL REPORTING STANDARDS

In January 2006, the CICA Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of the plan, accounting standards in Canada for public companies will converge with International Financial Reporting Standards ("IFRS") on January 1, 2011.

Although IFRS is principles based and uses a conceptual framework similar to Canadian GAAP, there are significant differences and choices in accounting policies, as well as increased disclosure requirements under IFRS. It is expected the most significant impact will be to property, plant and equipment.

Although IFRS 1 provides some relief on transition to IFRS, the changeover may materially affect the reporting of Company's reported financial position and results of operations. The Company is currently assessing the impact of the conversion from Canadian GAAP to IFRS on its results of operations, financial position and disclosures, and is in the process of developing an IFRS changeover plan. The plan will include an assessment of differences between Canadian GAAP and IFRS, accounting policy choices under IFRS, internal controls over financial reporting, potential system changes, and affects on internal controls including resources and training required for employees. Certain employees have been identified to manage this transition and to ensure successful implementation within the required timeframe. The Company will provide disclosures of the key elements of its plan and progress on the project as the information becomes available during the transition period. The Company is continuing to monitor new standards development as issued by the AcSB and the IASB.

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES
The significant accounting policies used by Sabretooth are disclosed in note 3 to the Annual Financial Statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstance may result in actual results or changes to estimate amounts that differ materially from current estimates. The following discussion identifies the critical accounting policies and practices of the Company and helps assess the likelihood of materially different results being reported.

RESERVES
Oil and gas reserves are estimates made using all available geological and reservoir data, as well as historical production data. All of the Company's reserves were evaluated and reported on by an independent qualified reserves evaluator. However, revisions can occur as a result of various factors including: actual reservoir performance, change in price and cost forecasts or a change in the Company's plans. Reserve changes will impact the financial results as reserves are used in the calculation of depletion and are used to assess whether asset impairment occurs. Reserve changes also affect other Non-GAAP measurements such as finding and development costs; recycle ratios and net asset value calculations.

DEPLETION
The Company follows the full cost method of accounting for oil and natural gas properties. Under this method, all costs related to the acquisition of, exploration for and development of oil and natural gas reserves are capitalized whether successful or not. Depletion of the capitalized oil and natural gas properties and depreciation of production equipment which includes estimated future development costs less estimated salvage values are calculated using the unit-of-production method, based on production volumes in relation to estimated proven reserves.

An increase in estimated proved reserves would result in reduction in depletion expense. A decrease in estimated future development costs would also result in a reduction in depletion expense.

UNPROVED PROPERTIES
The cost of acquisition and evaluation of unproved properties are initially excluded from the depletion calculation. An impairment test is performed on these assets to determine whether the carrying value exceeds the fair value. Any excess in carrying value over fair value is impairment. When proved reserves are assigned or a property is considered to be impaired, the cost of the property or the amount of the impairment will be added to the capitalized costs for the calculation of depletion.

CEILING TEST
The ceiling test is a cost recovery test intended to identify and measure potential impairment of assets. An impairment loss is recorded if the sum of the undiscounted cash flows expected from the production of the proved reserves and the lower of cost and market price of unproved properties does not exceed the carrying values of the petroleum and natural gas assets. An impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of cost and market price of unproved properties. The cash flows are estimated using the future product prices and costs and are discounted using the risk free rate. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment as a result of this ceiling test will be charged to operation as additional depletion and depreciation expense.

ASSET RETIREMENT OBLIGATIONS
The Company records a liability for the fair value of legal obligations associated with the retirement of petroleum and natural gas assets. The liability is equal to the discounted fair value of the obligation in the period in which the asset is recorded with an equal offset to the carrying amount of the asset. The liability then accretes to its fair value with the passage of time and the accretion is recognized as an expense in the financial statements. The total amount of the asset retirement obligation is an estimate based on the Company's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The total amount of the estimated cash flows required to settle the asset retirement

obligation, the timing of those cash flows and the discount rate used to calculate the present value of those cash flows are all estimates subject to measurement uncertainty. Any change in these estimated would impact the asset retirement liability and the accretion expense.

STOCK BASED COMPENSATION

The Company uses fair value accounting for stock-based compensation. Under this method, all equity instruments awarded to employees and the cost of the service received as considerations are measured and recognized based on the fair value of the equity instruments issued. Compensation expense is recognized over the period of related employee service, usually the vesting period of the equity instrument awarded.

INCOME TAXES

The determination of income and other tax assets and liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax asset may differ significantly from that estimated and recorded by management.

The recognition of a future income tax asset is also based on estimates of whether the Company is "more likely than not" to realize these assets. This estimate, in turn, is based on estimates of proved and probable reserves, future oil and natural gas prices, royalty rates and costs. Changes in these estimates could materially impact net income and the future income tax asset recognized.

LONG-TERM INVESTMENT

See "Liquidity and Capital Resources" section for an in-depth discussion of the estimates used to value the ABCP held by the Company.

OTHER ESTIMATES

The accrual method of accounting requires management to incorporate certain estimates including estimates of revenues, royalties and operating costs as at a specific reporting date, but for which actual revenues and costs have not yet been received. In addition, estimates are made on capital projects which are in progress or recently completed where actual costs have not been received by the reporting date. The Company obtains the estimates from the individuals with the most knowledge of the activity and from all project documentation received. The estimates are reviewed for reasonableness and compared to past performance to assess the reliability of the estimates. Past estimates are compared to actual results in order to make informed decisions on future estimates.

RISK MANAGEMENT

The Company is engaged in the exploration, development, production and acquisition of crude oil and natural gas. This business is inherently risky and there is no assurance that hydrocarbon reserves will be discovered and economically produced. Financial risks associated with the petroleum industry include fluctuations in commodity prices, interest rates and currency exchange rates along with the credit risk of the Company's industry partners. Operational risks include reservoir performance uncertainties, the reliance on operators of our non-operated properties, competition, environmental and safety issues, and a complex and changing regulatory environment.

The primary risks and how the Company mitigates them are as follows:

Commodity price and exchange rate volatility

Revenues and consequently cash flows fluctuate with commodity prices and the US/Canadian dollar exchange rate. Commodity prices are determined on a global basis and circumstances that occur in various parts of the world are outside of the control of the Company. The Company protects itself from fluctuations in prices by maintaining an appropriate hedging strategy, diversifying its asset mix and strengthening its balance sheet in order to take advantage of low price environments by making strategic acquisitions. We enter into commodity price contracts to actively manage the risks associated with price volatility and thereby protect our cash flows used to fund our capital program. We have used costless collars and swap contracts to manage these risks and to take advantage of market conditions. Net earnings for the period ended June 30, 2009 included $4,546 of realized gains and $2,407 of unrealized gain on these transactions. For contracts outstanding as at June 30, 2009, please see Note 14 of the Financial Statements.

Sabretooth is also exposed to fluctuations in the exchange rate between the Canadian and US dollar. Most commodity prices are based on U.S. dollar benchmarks that results in our realized prices being influenced mainly by the Canadian/U.S. currency exchange rates. The decline in the price of both oil and natural gas during the latter half of the year precipitated a decline in the Canadian dollar relative to the US dollar and one has tended to, at least partially, offset the effects of the other. As at June 30, 2009, the Company had no forward, foreign exchange contracts in place, nor any significant working capital items denominated in foreign currencies.

Credit risk
Credit risk arises from the potential loss resulting from a counterparty failing to meet its obligations in accordance with the agreed terms. The Company may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Company, such failures may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner. Substantially all of the accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. The Company generally extends unsecured credit to these customers and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions. Management believes the risk is mitigated by entering into transactions with long-standing, reputable, counterparties and partners. In many cases, the Company has offsetting receivables and payables with its partners and makes use of these offsets to mitigate any payment risk. Wherever possible, the Company requires cash calls from its partners on capital projects before they commence.

Receivables related to the sale of the Company's petroleum and natural gas production are mainly from major marketing companies who have excellent credit ratings. These revenues are normally collected on the 25th day of the month following delivery. The Company has not experienced any collection losses from its marketing companies.

The Company also has credit risk related to its investment in ABCP as described in Note 3 and 6 of the Financial Statements.

Access to Capital Risk
The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As the Company's revenues may decline as a result of decreased commodity pricing, it may be required to reduce capital expenditures. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Company to additional access to capital risk. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business financial condition, results of operations and prospects.

Current Economic Conditions
Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and are continuing in 2009, causing a loss of confidence in the global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward. Petroleum prices are expected to remain volatile for the near future as a result of

market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns.

NEW ALBERTA ROYALTY REGIME

Alberta Government New Royalty Framework

On April 10, 2008, the Alberta Government announced revisions to the Framework that was legislated in November 2008 and took effect on January 1, 2009. The revisions to the Framework include the following:

- Increased royalty rates on conventional and non-conventional oil and natural gas production in Alberta whereby royalty rates may increase to a maximum rate of 50 per cent;
- Sliding scale royalty calculations based on a broader range of commodity prices whereby conventional oil and natural gas royalty rates may increase up to maximum prices of approximately Cdn$120 per barrel and Cdn$16 per GJ, respectively;
- The elimination of royalty incentive and royalty holiday programs with the exception of specific programs relating to deep oil and natural gas drilling programs, innovative technology and enhanced recovery programs.

Subsequent to legislation of the NRF, the Alberta Government introduced the Transitional Royalty Plan (“TRP”) in response to the anticipated decrease in Alberta development activity resulting from the economic downturn and declining commodity prices. The TRP offers reduced royalty rates for new wells drilled on or after November 19, 2008 through December 31, 2013 that meet certain depth criteria. The TRP is in place for a maximum period of five years to December 31, 2013; all wells will convert to the NRF on January 1, 2014. The TRP is an “elective plan” whereby an election must be filed on an individual well basis to qualify for the TRP. The Company does not anticipate a significant benefit from the TRP in 2009 as the majority of the Company’s wells converted to the NRF on January 1, 2009.

On March 3, 2009, the Alberta Government announced the Energy Incentive Program (“EIP”) in response to the decrease in energy related development activity in the province. The incentive program will work in tandem with the NRF and the TRP and includes the following key elements:

- Drilling Royalty Credit – producers will receive a drilling credit for new wells drilled between April 1, 2009 and March 31, 2011. The drilling credit is based on a $200 per meter credit on total meters drilled.
- New Well Incentive Program – new production brought on-stream between April 1, 2009 and March 31, 2011 will qualify for a five per cent Alberta Crown Royalty rate for a period of 24 months subject to volume caps of 50,000 barrels of crown oil production and 150 Mmcf of crown natural gas production.

Sabretooth is evaluating the impact of all of the Alberta royalty changes on its operations and future drilling expenditures.