

## **ANTLER CREEK ENERGY CORP**

### **FORM 51-102F1**

### **RESTATED MANAGEMENT'S DISCUSSION AND ANALYSIS** **FOR THE SIX MONTH PERIOD ENDED JANUARY 31, 2010**

The following sets out management's discussion and analysis of the financial condition and results of operations the ("MD&A") of Antler Creek Energy Corp. ("Antler Creek" or the "Corporation") and incorporates all relevant information and considerations to that date and should be read in conjunction with the audited financial statement of the Corporation and its predecessor corporations Testudo Oil & Gas Exploration Ltd. and Batoche Energy Corp together with the accompanying notes thereto. This management's discussion and analysis is dated March 31, 2010, and is in respect of the six month period ended January 31, 2010 (the "Period Ended January 31, 2010").

#### **Non-GAAP Financial Measurements**

The Corporation has used certain measures of financial reporting that are commonly used benchmarks within the oil and gas industry in this MD&A that are considered non-GAAP measures. The measures used in this document include "funds from operations", "funds from operations per share" and "netback". The term funds from operations contained within the MD&A should not be considered as an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with GAAP. The Corporation believes that funds from operations are a useful supplementary measure as investors may use this information to analyze operating performance, leverage and liquidity. Funds from operations, if disclosed within this MD&A, represents cash flow from operating activities before changes in non-cash working capital. The Corporation believes that the term "netback" contained within the MD&A is also a useful supplementary measure as investors may use this information to analyze field level operating performance of the Corporation's oil and gas properties. Further supplemental indicators of performance common to the oil and gas industry are the measurement of costs and expenses on a per barrel of oil equivalent (boe). These non-GAAP measures may not necessarily be comparable to similarly titled measures used by other entities and readers of this MD&A are cautioned in attempting to make such comparisons.

#### **Other Measurements**

For the purposes of calculating unit costs, natural gas has been converted to a barrel of oil equivalent ("BOE" or "boe") using 6,000 cubic feet (6 Mcf) of natural gas equal to one barrel of oil (6:1), unless otherwise stated. The BOE conversion ratio of 6 Mcf to 1 barrel is based on an energy equivalency conversion method and does not represent a value equivalency. Therefore BOEs may be misleading if used in isolation. References to natural gas liquids ("NGL's") in this MD&A include condensate, propane, butane and ethane and one barrel of NGL's is considered to be equivalent to one barrel of crude oil equivalent (BOE).

#### **Forward-looking Information and Statements**

Certain information regarding Antler Creek Energy Corp. set forth in this report, including management's assessment of the Corporation's future plans, operations, properties, production and prospects contains forward looking information and statements that involve substantial known and unknown risks and uncertainties. Such forward-looking statements and information are based on the opinions and estimates of management at the date the statements are made and are subject to a variety of risks and uncertainties and other factors that could cause actual events or results to differ materially from those projected in the forward-looking statements and information. These factors include the inherent risks involved in the

exploration and development of oil and gas properties, the uncertainties involved in interpreting drilling results and other geological data, the possibility that royalties and other government levies or taxes could be increased, the possibility that laws relating to First Nations, environmental regulations, oil and gas conservation or production laws or protocols, other government regulations and laws could be amended or created in a manner that could adversely impact the Corporation's ability to develop any claims or mineral deposits held by the Corporation, fluctuating commodity prices, the possibility of project cost overruns or unanticipated costs and expenses, uncertainties relating to the availability and costs of financing needed in the future and other factors including unforeseen delays. As a junior oil and gas exploration focused enterprise, the Corporation faces risks, including those associated with exploration, development, approvals and the ability to access sufficient capital from external sources. Anticipated exploration and development plans relating to the Corporation's properties are subject to change. Readers should be aware that historical results are not necessarily indicative of future performance. Antler Creek's actual results, performance or achievements could differ materially from those expressed in, or implied by, such forward-looking information and statements, and accordingly, no assurance can be given that any events anticipated by the forward-looking statements will transpire or occur. or if any of them do, what benefits Antler Creek can derive therefrom. In some cases, forward-looking information and statements can be identified by terminology such as "may", "will", "should", "intends", "expects", "projects", "plans", "anticipates", "targets", "believes", "strives", "estimates", "continues", "designed", "objective", "maintain", "schedule" and similar expressions or statements that certain events or conditions "may" or "will" occur. The Corporation undertakes no obligation to update such forward-looking statements or information if circumstances or management's estimates or opinions should change unless required by law.

### **The Corporation**

The Corporation is a junior oil and gas exploration company whose focus is to explore for and develop oil and gas assets in high netback oil resource plays in the Williston Basin (Saskatchewan, Manitoba, Montana and North Dakota) and Texas Basin using horizontal wells and multistage fracturing completion techniques designed to increase the recovery volumes and rates of recovery beyond conventional recovery methods.

### **Recent Corporate History**

The Corporation is the resulting entity formed on May 31, 2009 upon the amalgamation of Antler Creek Energy Corp. ("ACEC") (after it had changed its name from Testudo Oil & Gas Exploration Ltd. on May 22, 2009) and Batoche Energy Corp ("BEC"). On May 25, 2009, ACEC acquired all of the issued and outstanding common shares of BEC.

### **No Comparative Data**

Because the fiscal period of the Corporation (July 31) does not match the fiscal period of BEC (January 31), and because BEC, as a private corporation, did not prepare certain statistical information, it is not possible to report comparative figures for increases of net asset value ("NAV"), reserve volumes, finding development and acquisition costs ("FD&A"), changes to future development capital ("FDC"), recycle ratios (which measures the return potential for every dollar reinvested given stable netbacks). Certain operational data will be presented for the period from November 1, 2009 to January 31, 2010. Operational data for the period from February 1, 2009 to July 31, 2009 is available in the MD&A filed by the Corporation for the period ended July 31, 2009. Operational data for the period from August 1, 2009 to October 31, 2009 is available in the MD&A filed by the Corporation for the period ended October 31, 2009.

## Overall Performance

The unaudited financial statements of the Corporation report a loss of \$125,658 for the three month period ended January 31, 2010 and a loss of \$244,117 for the six months ended January 31, 2010. The financial statements reflect a deficit of \$626,081. The financial statements reflect a negative working capital of \$688,215 (current assets less current liabilities). Included in the accounts payable is an amount of \$182,250 to Aldon Oils Ltd. ("Aldon"). Of the debt owing to Aldon, the sum of \$140,000 represents the Corporation's proportionate share of the cost of completing a Bakken well (1D8-6-2D8 5-9-9-W2M) in December 2009. The balance owing to Aldon does not reflect any reduction of the accounts payable to Aldon (joint venture operator) for capital and operational charges which management believes are not permitted by the joint operating agreement (which incorporates the CAPL Operating and Accounting Procedure). Included in the accounts payable is the sum of \$409,968 owing to Crescent Point Energy Corp ("Crescent Point"), which represents the unpaid portion of the capital cost of the Corporation's proportionate share of the cost (20%) of the cost to drill, case, complete and equip (with standalone batteries) 2 Bakken wells (Section 13-8-11-W2M). The Corporation has been billed \$554,000 to date and expects to be invoiced for an additional \$160,000 in the next two months. The wells were drilled in December and were completed by the end of January 2010. (See "Drilling/Operational Results" for a discussion of the performance of the 2 new wells and the newly fraced well).

## Restatement

The original interim financial statements from six months ended January 31, 2010, were prepared without an auditor review and did not include adjustments for accretion, depletion and depreciation, and future income taxes. As a result of the auditor review, these financial statements include adjustments for accretion, depletion and depreciation, future income taxes, and other operation accruals.

The balance sheet has been restated as follows:

	<u>As reported</u>	<u>Adjustment</u>	<u>Restated</u>
Accounts receivable	\$ 17,533	\$ (8,197)	\$ 9,336
Petroleum and natural gas properties and equipment	3,251,428	(399,545)	2,851,883
Accounts payable and accrued liabilities	(637,081)	1,397	(635,684)
Current portion due to related party	(118,319)	(4,150)	(122,469)
Future income taxes	(296,018)	73,973	(222,045)
Asset retirement obligation	(66,549)	(12,862)	(79,411)
Share capital	(1,718,132)	5,798	(1,712,334)
Deficit	282,495	343,586	626,081
	<u>\$ 715,357</u>	<u>\$ -</u>	<u>\$ 715,357</u>

The statements of comprehensive loss and deficit have been restated as follows:

	Three Months Ended January 31, 2010			Six Months Ended January 31, 2010		
	As reported	Adjustment	Restated	As Reported	Adjustment	Restated
Petroleum and natural gas sales	\$ (307,705)	\$ 7,324	\$(300,381)	\$(449,926)	\$ (13,922)	\$ (463,848)
Interest income	-	103	103	-	(1,430)	(1,430)
Accretion	-	764	764	-	1,565	1,565
Depletion and depreciation	-	242,010	242,010	-	429,371	429,371
General and administrative	139,386	(22,427)	116,959	149,469	6,731	156,200
Oil and gas production costs	-	-	-	123,068	1,042	124,110
Future income tax recovery	-	(47,458)	(47,458)	-	(79,771)	(79,771)
	<u>\$ (168,319)</u>	<u>\$ 180,316</u>	<u>\$ 11,997</u>	<u>\$(177,389)</u>	<u>\$ 343,586</u>	<u>\$ 166,197</u>

A summary of the balance sheet information is shown below:

	July 31, 2009 (Audited)	Jan. 31, 2010 (Unaudited) (as restated)
<b>CURRENT ASSETS</b>	\$676,105	97,827
Petroleum and Natural Gas Properties and Equipment	<u>2,515,445</u>	<u>2,851,883</u>
Total Assets	<b>\$3,191,550</b>	<b>\$2,949,710</b>
<b>CURRENT LIABILITIES (excluding amounts due to related party)</b>	368,905	663,573
Due to Related Party	998,099	772,617
Future Income Taxes	296,018	222,045
Asset Retirement Obligation	<u>66,529</u>	<u>79,411</u>
<b>TOTAL LIABILITIES</b>	<b>\$1,729,551</b>	<b>\$1,737,646</b>
Shareholder Capital	1,843,943	1,838,145
<b>DEFICIT</b>	<b>(381,964)</b>	<b>(626,081)</b>

A summary of the income statement information is shown below:

	<b>July 31, 2009 (Audited)</b>	<b>Six Months Ended January 31, 2010 (Unaudited) (as restated)</b>	<b>Three Months Ended January 31, 2010 (Unaudited) (as restated)</b>
<b>REVENUE</b>			
Petroleum and Natural Gas Sales	\$178,855	\$463,848	\$300,381
Royalties	(22,891)	(62,029)	(44,486)
Other Income		1,430	
Interest Income	<u>4,900</u>	-----	<u>(103)</u>
	\$160,864	\$403,249	\$255,792
Oil and Gas Production Costs	<u>(34,286)</u>	<u>(124,110)</u>	<u>(61,250)</u>
	\$126,578	\$279,139	\$194,542
<b>EXPENSES</b>			
Professional Fees <sup>(1)</sup>	246,767	99,264	83,432
Stock Based Compensation <sup>(2)</sup>	51,328	-----	-----
TSXV Fees and public company costs	24,859	-----	-----
Office	23,785	32,352	24,447
Rent	5,859	17,264	8,692
Bank Interest and Charges	4,502	589	388
Interest on Related Party Debt	20,911	15,891	7,925
Depletion and Depreciation (3)	123,050	429,371	242,010
Accretion	<u>581</u>	<u>1,565</u>	<u>764</u>
<b>GAIN (LOSS) BEFORE INCOME TAXES</b>	<b>\$(375,064)</b>	<b>\$(323,888)</b>	<b>\$(173,116)</b>
Future Income Tax (Reduction)	<u>(201,015)</u>	<u>(79,771)-</u>	<u>(47,458)</u>
<b>GAIN (LOSS)</b>	<b>\$(174,049)</b>	<b>\$(244,117)</b>	<b>\$(125,658)</b>
Deficit at the Beginning of Period	<u>(207,915)</u>	<u>(381,964)</u>	<u>(500,423)</u>
Deficit — End of Period	\$(381,964)	\$(626,081)	\$(626,081)
Gain (Loss) Per Share Basic and Diluted	(0.08)	(0.061)	(0.032)
Weighted Number of Shares Outstanding	2,090,849	4,000,000	4,000,000

Notes:

- (1) The sum of approximately \$225,000 of these fees reflect the cost incurred by ACEC to complete its acquisition of BEC and should not be recurring costs.
- (2) These costs are non-cash items which resulted when ACEC granted stock options to its directors concurrent with the acquisition of BEC and when ACEC granted options to PI Financial Corp as part of a private placement.
- (3) These sums are non cash items.

There are several positive industry and economic trends which will influence the ability of the Corporation to raise equity to continue to realize on the inherent value of its assets, including: (a) increase in commodity prices; (b) new drilling equipment, techniques and technologies for horizontal wells; (c) new completion equipment, techniques and technology; (d) lower costs; (e) higher overall recovery volumes; (f) higher primary recovery volumes; (g) higher initial production rates; and (h) lower water volumes as a result of the drilling and completion equipment, techniques and technology. Two additional factors should be considered. First, the building of pipeline infrastructure in the Viewfield area will permit the gathering of natural gas and solution gas which will: (a) increase the volumes of oil and natural gas substances sold; (b) reduce the cost to truck oil and other operating costs; and (c) increase operating netbacks. The Corporation's lands are tied-in or are proximate to pipelines which allows for the collection of natural gas and solution gas. Second, the potential exists for secondary recovery which might increase the recovery factor.

To summarize, the Corporation's important properties are located in Southeast Saskatchewan, Canada and consist of 4,960 gross acres (4,249 leased acres) (1,800 net acres). The Corporation has approximately 2,500 gross acres in Township 9 and 10 Range 11 W2M (near Fillmore, Saskatchewan) ("Fillmore Lands"). The Corporation's most important plants, facilities and installations are as follows:

Well Location	WI %	Oil/Gas	Producing Since	Pipeline Proximity/transportation
HZ S 1B4-24-4B4-13-8-11-W2M	20%	Oil	April 08	Tied-into CP battery (not operational)
HZ S 2A1-24-3A1-13-8-11-W2M	20%	Oil	April 08	Tied into CP battery (not operational)
HZ S 1B4-6-3B1 31-8-9-W2M	22.5%	Oil	April 08	Tied-into CP battery
HZ S 2A3-6-3A3-31-8-9-W2M	22.5%	Oil	August 08	Tied-into CP battery
HZ W 4A1-6-4A1 5-9-9-W2M	25%	Oil	March 08	Tanks on Roadway/Building Pipeline
HZ W 1D8 6-2D8 5-9-9-W2M	25%	Oil	August 08	Tanks on Roadway/Building Pipeline
HZ S 2A2-24-3A2 13-8-11-W2M	20%	Oil	December 2009	Tied-into CP battery (not operational)
HZ S 1B3-24-4B4 13-8-11-W2M	20%	Oil	December 2009	Tied into CP battery (not operational)

### Average Sales Prices

The average sales price received by for the period from November 1, 2009 to January 31, 2010 was as follows:

	Category		December 1,2009	January 31, 2010	Category
Aldon	oil	c/m	\$464.00	\$443.00	\$471.00
		bbl	\$73.76	\$70.42	\$74.88
Crescent Point	oil	c/m	\$76.00	\$71.70	\$80.76
		bbl	\$478.00	\$451.00	\$508.00
In Cdn \$	gas	c3/m3	\$139.00	\$214.00	\$216.00
Prices have been rounded and averaged	NGL	c/m	\$340.00	\$352.00	\$317.00
		bbl	\$54.05	\$55.96	\$50.40

### Operational Results

Antler Creek does not operate any of its producing properties. The operational results vary depending on the operator. The tables below reflect 100% of the production from the lands (described in the tables) for the period from November 1, 2009 to January 31, 2010.

Operator							
Crescent Point Energy Corp. West 31-8-9-W2M (2 wells) Section 13-8-11-W2M (4 wells)				Aldon Oils Ltd. South 5-9-9-W2M (2 wells)			
	Gross \$	Per boe	Per c/m	Per c/m	Per boe	Gross \$	
Agg Volume Oil	1,843 cm					988 cm Agg	Volume Oil
Gas and NGL's 100% Production	11,592 bbl					6,215 bbl	
Aggregate Price	\$886,489	\$76.47	\$481.00	\$472.73	\$75.15	\$467,057	Aggregate Price
Royalty	93,740	8.08	50.86	58.47	9.30	57,777	Royalty
GOR	-----			6.49	1.03	6.418	GOR
Revenue Less Royalties	<b>\$792,749</b>	<b>\$430.14</b>	<b>68.38</b>	<b>\$407.75</b>	<b>64.70</b>	<b>\$402,864</b>	Revenue Less Royalties
Equipment rentals	-			19.63	3.12	19,460	Equipment rentals <sup>(1)(2)</sup>
Operators fees	1,721	0.15	0.93	3.13	0.50	3,100	Operators fees <sup>(1)</sup>
Approved Admin fees <sup>(1)</sup>	4,014	0.34	3.17	1.67	0.27	1,650	Approved Admin fees <sup>(1)</sup>
	---	----	---	17.60	2.73	16,986	Unexplained Admin Fees <sup>(1)(2)</sup>
<b>Treatment<sup>(1)</sup></b>	<b>11,057</b>	<b>0.95</b>	<b>6.00</b>	<b>19.36</b>	<b>3.07</b>	<b>19,126</b>	<b>Treatment charges<sup>(1)(2)</sup></b>
<b>Trucking (oil, water and hauling)</b>	<b>16,402</b>	<b>1.43</b>	<b>9.00</b>	<b>65.40</b>	<b>10.40</b>	<b>64,622</b>	<b>Trucking<sup>(1)(2)</sup> (oil, water and hauling)</b>
<b>Disposal</b>	<b>7,528</b>	<b>0.65</b>	<b>4.08</b>	<b>10.10</b>	<b>1.60</b>	<b>9,978</b>	<b>Disposal</b>
Other Expenses	30,812	2.65	16.71	16.50	2.63	16,313	Other Expenses
Gas Processing	-----	-----	-----	-----	-----	-----	Gas Processing
<b>Total Expenses</b>	<b>\$71,174</b>	<b>6.14</b>	<b>38.64</b>	<b>152.92</b>	<b>24.31</b>	<b>151,085</b>	<b>Total Expenses</b>
<b>Profit/Netback</b>	<b>721,635</b>	<b>391.55</b>	<b>62.25</b>	<b>254.10</b>	<b>40.40</b>	<b>251,060</b>	<b>Profit/Netback</b>

Note:

- (1) Denotes Non Arms Length Billing by Operator
- (2) will be subject to joint venture audit along with other capital charges not reflected in the operating calculations shown above.

There is a significant difference between the operating netbacks between wells operated by Crescent Point and wells operated by Aldon. The wells have the same maintenance, treatment, trucking and disposal requirements however, the two differences are that: (a) Crescent Point has tied in the wells by pipe to a battery for West 31-8-9-W2M; and (b) Crescent Point engages arms length contractors. Aldon charges non-arms length rates for certain services. The Corporation will be auditing all of the non-arms length joint venture expenses billed by Aldon from April 2008 to January 31, 2010. It is the opinion of management that the operating costs of Crescent Point reflect a reasonable industry standard cost structure and will reflect the operating netback of the Corporation if it operates its own properties.

### Drilling/Operational Results

The Corporation has non-operated working interests in 8 producing Bakken wells producing from 1,280 gross acres (280 net acres). Six wells are operated by Crescent Point and two by Aldon. Production from the lands averaged 90 boe/d for the month of January 31, 2010 (based on average of 25.75 working days/well).

The Corporation was expecting higher production rates because two wells were drilled and completed by Crescent Point in January 2010 (2A2-24-3A2 13-8-11-W2M and 1B3-24-4B4 13-8-11-W2M). The production has not been as expected. The Corporation is uncertain whether expected production can be obtained by well maintenance or other remedial work. The Corporation was expecting an increase in production as a result of the frac of 1D8-6-2D8 5-9-9-W2M. The production has not been what was expected.

The production for the third quarter ending April 30, 2010 is expected to be between 50-70 boe/d (90% oil) depending on the success in remediating the two new wells. Production could increase in the fourth quarter if the Corporation drills the 2 Bakken wells described as HZ S 2A2-24-3A2 13-9-9-W2M and HZ S 1B12-13-4B4 13-9-9-W2M. (See "Contractual, Commitment Contingencies and Drilling Plans"). The Corporation will be the operator for the Fillmore Lands (3,200 acres (gross) (2,609 leased acres) of undeveloped lands in Twp 9 and 10 of Range 11 W2M) and likely the Conoco Lands (NE, SE and SW Section 13-9-9-W2M).

### Capital Expenditures

	February 1, 2009 to July 31, 2009	August 1, 2009 to October 31, 2010	November 1, 2009 to January 31, 2010
Property Acquisitions	Nil		
Exploration	Nil		
Development	\$21,871	\$41,024	\$713,489
Equipment	36,404		
Dispositions	Nil		
Total capital expenditures	\$58,275	\$41,024	\$713,489

### Contractual Commitments, Contingencies and Drilling Plans

As of January 31, 2010, the only commitment of the Corporation was a \$100,000 performance penalty payable to ConocoPhillips (BRC) Partnership ("Conoco") if the Corporation failed to drill 2 Bakken wells on SE, NE and SW Section 13-9-9-W2M by the summer of 2010. The Corporation would do so by seeking to drill one 1400m Bakken well (Antler Creek Heward HZ S 2A2-24-3A2 13-9-9-W2M) and a bilateral 600m leg horizontal Bakken well (bilateral construction)(to be described as Antler Creek Heward HZ S 1B12-13-4B4 13-9-9-W2M). Because the Corporation has 75% of the mineral rights it is expected that Antler Creek would drill and complete this well. As operator, in order to complete the well prior to mineral lease expiry dates, the Corporation may be obligated to pay 100% of the estimated \$4,000,000 capital cost to drill, case and complete the one 1400m well and the two 600m wells.

Crescent Point has recently entered into a letter of intent to lease the 25% interest. To date no joint operating agreement has been signed with the lessee of the 25% interest for the development of the NE, SE and SW Section 13-9-9-W2M. The Corporation has applied to the Saskatchewan government for a ministerial order permitting the pooling and development of the land and expects to obtain such an order prior to the mineral lease expiry date. The drilling of the HZ S 2A2-24-3A2 13-9-9-W2M and HZ S 1B12-13-4B4 13-9-9-W2M wells should be completed by July 2010 if the pooling order can be obtained by the end of April 2010. Production for the fourth quarter ending July 31, 2010 is uncertain because it is dependant upon the timing of the wells described above.

The following table sets forth the contractual commitment of the Corporation as of January 31, 2010:

Contractual Obligations	Payments Due By Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Long Term Debt <sup>(1)</sup>	772,617	122,469	444,804	205,344	0
Capital Lease Obligations	0	0	0	0	0
Operating Leases	0	0	0	0	0
Purchase Obligations	0	0	0	0	0
AFE Obligations	600,000	600,000			
Other Obligations <sup>(2)</sup>	100,000	100,000	0	0	0
Total Contractual Obligations	1,472,617	822,469	444,804	205,344	

Notes:

- (1) This a related party loan.
- (2) This is the performance penalty which would be payable to Conoco if the Corporation fails to drill 2 Bakken well on Section 13-9-9W2M before July 2010. To meet its obligation and to earn its interest, the Corporation would be required to commit to \$2 - \$4,000,000 depending on the nature and scope of the operations and who was the operator. This would increase the Year 1 commitments to between \$3 - \$5,000,000.

## Liquidity

The junior oil and gas business is inherently risky and capital intensive and can require significant capital resources to grow reserves and cashflow. Given the nature of the oil and gas business and the size of the Corporation, it will need to access capital markets to raise funds to meet its commitments and expand its production and reserve base.

As at January 31, 2010, the Corporation had a working capital deficiency of \$688,215. The Corporation does not have any line of credit or any bank debt. If additional equity is not raised and further drilling does not take place the Corporation may fail to meet certain of its financial debt covenants on its loan agreements during the year.

The Corporation has budgeted \$5.0M of capital expenditures for the balance of 2010 for Saskatchewan assets. In addition to the wells described in "Commitments, Contingencies and Drilling Plans", the Corporation plans to drill another 2 — 1400m Bakken wells in Section 13-9-9-W2M. The cash flow from the wells would permit the remainder of the development and permit the Corporation to drill on other lands or make other acquisitions. The Corporation expects to rely on internally generated cash flows to finance the remainder of the capital program and as such the program could be reduced if the business environment weakens further in the second half of 2010.

The Corporation is also exploring the possibility of acquiring mineral rights in South Texas. To do so will require additional capital. To secure adequate capital resources, the Corporation may raise funds during the year the Corporation also intends to continue to evaluate corporate acquisitions, mergers or divestitures.

## Capital Resources

The capital resources of the Corporation have been discussed above.

## Off Balance Sheet Arrangements

There are no off balance sheet arrangements.

### Transactions with Related Parties

As part of the consideration paid to acquire BEC, the Corporation entered into a loan agreement for \$1,100,000 with a related party, who is a shareholder, director and officer of the Corporation. The debt bears interest at 4% per annum and is due within 48 months of the closing of the transaction, or by May 25, 2013. The loan shall be repaid from cash flow from all operations at the rate of 75% of gross monthly cash flow. If cash flow is withheld by operators to pay capital or operational authorization for expenditures ("AFE"), then the non-payment of the loan shall not be considered as an event of default. Commencing January 1, 2010, there shall be a minimum monthly blended payment of \$20,000 per month. The debt is secured by a general security agreement, being a first charge on all assets of the Corporation. Any new advances to the related party will bear interest at 7% per annum. Included in interest on related party debt is \$15,891 (Nil as at January 31, 2009) of interest payable during the year on this loan. Related party loan balance repayment terms are approximately:

2010	\$	122,469
2011		217,962
2012		226,842
2013		205,344
Total	\$	<u>772,617</u>

Included in general and administrative expenses are legal expenses of \$77,380 as of January 31, 2010 (\$57,260 as at January 31, 2009) and rent expenses of \$17,264 (Nil as at January 31, 2009) paid to Gregory J. Leia Professional Corporation, a company related by virtue of a common shareholder. Included in accounts payable and accrued liabilities is \$23,500 (\$Nil as of January 31, 2009) related to these transactions. These transactions were conducted in the normal course of operations and have been measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Two directors own percentage working interests in the Fillmore Lands. Another director, owns shares in Testudo Resources Ltd. which has a gross overriding royalty over parts of the Fillmore Lands. The gross overriding royalty is 2.5% with a bonus 1% if the production from the Red River or Winnipegosis zones exceed 1,000 boe/d in any 640 acre spacing unit.

### Contingent Liabilities

The Corporation is named as defendant in a lawsuit in Saskatchewan, which has been commenced by a party which had sold mineral rights to the Corporation and farmout mineral rights to the Corporation. The action seeks a declaration confirming that a consultant of the vendor/farmor did not have a right of first refusal or any rights to the mineral interests sold or farmed out because the consulting agreement was terminated. The consultant filed a defence and counterclaim against the vendor/farmor alleging that the consultant is entitled to a 10% gross working interest (5% net) in the mineral rights sold to the Corporation and farmed out to the Corporation. The consultant admits that the consulting agreement was terminated, but notwithstanding claims that the contractual obligation to offer the right of first refusal continued after the termination of the consulting agreement. In the alternative, the consultant claims that the vendor/farmor was in a position of trust and confidence and owed the consultant a fiduciary duty. In breach of the fiduciary duty, the party entered into specified oil and gas mineral leases.

The Corporation believes the claim to be without merit. In the event that the consultant is successful in the counterclaim, then: (a) the Corporation will likely be required to assign to the consultant an undivided 5% net working interest in the Bakken formation in the Mississippian period underlying the West 31-8-9-W2M; (b) the Corporation will be required to assign an undivided 5% net working interest in the Bakken

formation in the Mississippian period underlying the South 5 9-9 W2M; and (c) the Corporation will likely have to account to the consultant for any net revenues (net of capital costs advanced) relating to the 5% net working interest. The effect on the financial statements of the Corporation as of January 31, 2010 would be: (a) reduction in gross revenues; (b) reduction in royalties; (c) reduction in operating expenses; (d) reduction in capitalized costs; (e) recovery of the capital costs advanced to drill 4 wells; and (f) recovery of some general and administrative expenses related to the 4 wells.

## **Second Quarter**

Because the transaction with BEC concluded May 25, 2009, second quarter results cannot be compared with prior periods and all relevant information has been provided in the disclosure above.

## **Proposed Transactions**

The Corporation intends to acquire mineral rights in Southeast Saskatchewan and Texas. Further details will be press released in accordance with timing prescribed by securities laws.

## **SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES**

The financial statements of the Corporation have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP"). The financial statements have, in management's opinion, been properly prepared using careful judgment within reasonable limits of materiality and within the framework of the significant accounting policies summarized below.

### **Cash and cash equivalents**

Cash consists of cash on hand and bank deposits. Highly liquid investments with maturities of three months or less at date of purchase are considered to be cash equivalents.

### **Petroleum and natural gas properties and equipment**

The Corporation uses the successful efforts method of accounting for petroleum and natural gas activities. Costs to acquire mineral interests in petroleum and natural gas properties, to drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves are expensed at the time that the exploratory drilling proves to be unsuccessful. Geological and geophysical costs and costs of carrying and retaining unproved properties are expensed as they are incurred. Unproved oil and gas properties are periodically assessed for impairment after considering the remaining term of the lease, drilling results and the evaluation of geological data and other information. A loss is recognized at the time of impairment by providing an impairment allowance.

Capitalized costs of producing petroleum and natural gas properties, after considering estimated salvage values, are depleted over their estimated useful life on a declining balance basis of 30%. Capitalized costs of producing petroleum and natural gas equipment, after considering estimated salvage values, are depreciated over their estimated useful life on a declining balance basis of 25%.

Some portion of the exploration, development and production activities of the Corporation are conducted jointly with others and, accordingly, the financial statements reflect only the Corporation's proportionate interest in such activities.

### **Asset retirement obligations**

The Corporation calculates and records the estimated fair value of each asset retirement obligation in the period a well or related asset is drilled, constructed or acquired. Fair value is determined using the present value of the estimated future cash outflows to abandon the asset and restore the site discounted at the Corporation's credit adjusted risk-free interest rate. The obligation is reviewed regularly by the Corporation's management based on the current regulations, costs, technologies and industry standards. The discounted obligation is initially capitalized as part of the carrying amount of the related petroleum and natural gas properties and a corresponding liability is recognized. The increase in petroleum and natural gas properties is depleted on the same basis as the remainder of the petroleum and natural gas properties. The liability is accreted against income until it is settled or the property is sold. Actual restoration expenditures are charged as reductions to the accumulated obligation when incurred.

### **Income taxes**

The Corporation follows the liability method of income tax allocation. Under this method, current income taxes are recognized for the estimated income taxes payable for the current year. Future income tax assets and liabilities are recognized for temporary differences between the tax and accounting bases of assets and liabilities as well as for the benefit of losses available to be carried forward to future years for tax purposes that are likely to be realized. Future tax assets and liabilities are measured using substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled.

### **Revenue recognition**

Revenue associated with the sale of petroleum and natural gas are recorded when title passes to the customer. Revenue from petroleum and natural gas production from properties in which the Corporation has an interest with other producers is recognized on the basis of the Corporation's net working interest. Interest income is recognized as it is earned on a time proportion basis.

### **Stock-based compensation**

The Corporation has established a stock option plan for officers, employees, directors and service providers. In order to calculate the compensation expense, the fair value of the stock options is estimated using the Black-Scholes option-pricing model that takes into account, as of the grant date: exercise price, expected life, current price, expected volatility, expected dividends and risk-free interest rates.

Consideration paid to the Corporation upon the exercise of the stock options is recorded as an increase to share capital and an adjustment is made to transfer to share capital the compensation expense previously recognized in contributed surplus for the specific stock options exercised.

The Corporation does not incorporate an estimated forfeiture rate for stock options in determining the stock option fair value in order to calculate its compensation expense, as the Corporation has assumed that all stock options granted will vest. Accordingly, forfeitures are accounted for as they occur and are treated as a change in estimate. The cumulative effect of the change on current and prior periods is recognized in the period of the change in estimate. In the event that vested options expire without being exercised, previously recognized compensation costs associated with such stock options are not reversed.

### **Per share calculations**

Basic loss per share is calculated by dividing net loss by the weighted average number of common shares outstanding during the period. The Corporation applies the treasury stock method for the calculation of diluted net loss per share whereby the effect of in-the-money instruments such as stock options and

warrants affect the calculation. The treasury stock method assumes that the proceeds from the exercise of in-the-money stock options and warrants plus the unamortized portion of stock-based compensation are used to purchase common shares of the Corporation at the weighted average market price during the period.

### **Flow-through shares**

The Corporation, from time to time, finances a portion of its exploration activities through the issuance of flow-through shares. The related resource expenditure deductions normally available for income tax purposes are renounced to investors in accordance with income tax legislation. Share capital is reduced and the future income tax liability is recorded for the estimated tax benefits transferred to investors when the resource expenditure deductions are renounced and the tax filings are prepared and filed.

### **Financial instruments**

The Corporation has designated its financial instruments as follows:

- (a) Cash and cash equivalents are classified as "Held for Trading" and are measured at fair value, with fair value of cash equivalents being determined by the market value plus accrued interest. Transaction costs are expensed.
- (b) Accounts receivable are classified as "Loans and Receivables". These financial assets are recorded at values that approximate their amortized cost using, the effective interest method. Transaction costs are expensed.
- (c) Accounts payable and accrued liabilities and due to related party are classified as "Other Financial Liabilities". These financial liabilities are recorded at values that approximate their amortized cost using the effective interest method. Transaction costs are expensed.

### **Measurement uncertainty**

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amount of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the year. Estimates and assumptions include the estimated outcome of contingent liabilities, the estimated useful life of petroleum and natural gas properties and equipment for depletion and depreciation purposes, the timing and cost of future well abandonments used to calculate the asset retirement obligation, the future cash flow models developed in applying asset impairment tests, the fair value of stock options and warrants, the estimated current portion of related party debt, the net recoverable amount of accounts receivable and petroleum and natural gas properties and equipment and the tax rates at which temporary differences between the tax bases and accounting bases of assets and liabilities are expected to reverse. By their nature, these estimates are subject to measurement uncertainty, and the effect on the financial statements of changes in such estimates in future periods could be significant.

## CHANGES IN ACCOUNTING POLICIES

### Business Combinations

CICA Handbook Section 1582, Business Combinations is required to be applied to fiscal years beginning on or after January 1, 2011 and harmonizes current GAAP with International Financial Reporting Standards. Effective August 1, 2008 the Corporation early adopted this section on a prospective basis.

### International Financial Reporting Standards (IFRS) Conversion

During 2008, the CICA Accounting Standards Board ("ACSB") confirmed the changeover to IFRS from Canadian GAAP will be required for publically accountable enterprises interim and annual financial statements effective for fiscal years beginning on or after January 1, 2011. The changeover to IFRS is a significant undertaking that may materially affect the Corporations' reported financial position and operations.

To date, the CFO, the primary sponsor of the project, has prepared a summary level changeover plan for IFRS conversion that has been presented to the Audit Committee of the Board of Directors. Hallmarks of the changeover plan include initial definition of the tasks required for conversion, a timetable for completion of the tasks, an estimate of the effort and duration associated with the conversion, prioritization of the tasks and the assignment of key personnel within the organization. The conversion plan has been divided into two distinct phases. The first is the identification of the significant accounting policies that relate to each of the major conversion items within the firm. Management is at this phase. In the next phase, management of the dual reporting under Canadian GAAP and IFRS as required. This phase determines the mapping between the different accounts identified in our chart of accounts and applies the mapping to generate the IFRS reporting. Dual reporting capability will be required as of April 1, 2010, so that the Corporation can prepare comparative information for IFRS reporting which will begin in the first quarter of 2011.

### Other Information

#### Summary of Quarterly Results

A summary of selected financial information for the eight most recently completed quarters is as follows:

	Year-End Combined Twelve Months Ended July 31, 2008	Q1 Three Months Ended Oct 31, 2008	Q2 Three Months Ended Jan 31, 2009	Q3 Three Months Ended April 30, 2009	Q4 Three Months Ended April 30, 2009	Year-End Combined Twelve Months Ended July 31, 2009	Q1 Three Months Ended Oct 31, 2009	Q2 Three Months Ended Jan 31, 2010
	Audited	Unaudited	Unaudited	Unaudited	Unaudited	Audited	Unaudited (as restated)	Unaudited (as restated)
Total Revenue	\$20,852	\$2,923	\$1,481	\$1,768	\$154,592	\$160,864	\$147,457	\$255,792
Net Income (loss)	\$(124,428)	\$(71,138)	\$(62,432)	\$(61,262)	\$(180,232)	\$(375,064)	\$(118,459)	\$(125,658)
Net Income (Loss) Per Share	\$(0.08)	\$(0.013)	\$(0.12)	\$(0.01)	\$(0.04)	\$(0.08)	\$(0.29)	\$(0.032)
Total Assets	\$597,029	\$540,725	\$447,959	\$351,697	\$3,191,550	\$3,191,550	\$2,895,306	\$2,949,710
Long-term Liabilities	Nil	Nil	Nil	Nil	\$1,012,715	\$1,012,715	\$980,255	\$951,604

For the Period Ended January 31, 2010, the Corporation reported no discontinued operations and declared no cash dividends.

### Analysis of Selected Annual Information

The following table sets forth a breakdown of material components of the general and administration costs of the Corporation for the Period Ended January 31, 2010.

	Total Twelve Months Ended July 31, 2008	Q1 Three Months Ended Oct 31, 2008	Q2 Three Months Ended Jan 31, 2009	Q3 Three Months Ended April 30, 2009	Q4 Three Months Ended July 31, 2009	Total Twelve Months Ended July 31, 2009	Q1 Three Months Ended Oct 31, 2009	Q2 Three Months Ended Jan 31, 2010
	Audited	Unaudited	Unaudited	Unaudited	Unaudited	Audited	Unaudited (as restated)	Unaudited (as restated)
Bank Charges	\$433	\$84	\$134	\$142	\$4,142	\$4,502	\$201	\$388
Office	\$12,003	\$11,527	\$9,903	\$2,837	\$482	\$23,785	\$7,905	\$24,447
Investor Relations	\$21,726	-----		\$5,000	\$19,859	\$24,859	Nil	Nil
Legal Fees	\$111,118	\$63,600	\$47,254	\$53,081	\$43,665	\$207,600	\$15,832	\$77,380
FS Fees		-----	-----	-----	\$39,167	\$39,167	Nil	\$6,052

The Corporation has not entered into any guarantees requiring disclosure.