
The following Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of Pinecrest Energy Inc., formerly Antler Creek Energy Corp. ("Pinecrest" or the "Company") is for the three and twelve months ended July 31, 2010 ("Reporting Periods") with comparative results for the three and twelve months ended July 31, 2009 ("Comparative Periods"). For a full understanding of the financial condition and results of operations of the Company, this MD&A should be read in conjunction with the audited annual financial statements for the year ended July 31, 2010 and 2009. These documents, including the Annual Information Form and additional information about Pinecrest are available on SEDAR at www.sedar.com. This MD&A is dated as of October 5, 2010.

FORWARD LOOKING STATEMENTS

Certain statements in this document constitute forward-looking statements under applicable securities laws. Such statements are based on assumptions of future events and actual results could vary from these assumptions. Events or circumstances may cause actual results to differ materially from those predicted as a result of numerous known and unknown risks, uncertainties and other factors, many of which are beyond the control of the Company. These include, but are not limited to, risks associated with oil and gas exploration, production, marketing and transportation, such as loss of market, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, imprecision of accounting estimates, environmental risk, and competition from other producers and ability to access sufficient capital from internal and external sources. There can be no assurance that forward-looking information will prove to be accurate, as results and future events could differ materially from those expected or estimated in such statements. **As such, readers are cautioned not to place undue reliance on these forward-looking statements.** Furthermore, the Company disclaims any intention or obligation to update or revise these forward-looking statements as a result of new information, future events or otherwise.

All amounts are expressed in Canadian dollars unless otherwise noted. Petroleum and natural gas reserves and volumes are converted to an equivalent measurement basis referred to as a "barrel of oil equivalent" ("boe") on the basis of 6 thousand cubic feet of natural gas equal to 1 barrel of oil. This conversion is based on an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. Readers are cautioned that boe figures may be misleading, particularly if used in isolation. The term boe per day (boe/d) has been used throughout this MD&A.

NON-GAAP MEASURES

The terms "cash flow from operations" and "cash flow from operations per share" in this discussion are used as an indicator of the Company's operating performance. These are not recognized measures under Canadian generally accepted accounting principles ("GAAP"). As such, Pinecrest's method of calculating cash flow from operations may differ from other companies and accordingly it may not be comparable to measures used by other companies. Readers are cautioned that this measure should not be construed as an alternative to net earnings as calculated under GAAP as an indication of Pinecrest's performance. Pinecrest expresses cash flow from operations as cash flow from operating activities before changes in non-cash working capital and asset retirement expenditures. Cash flow from operations per share is calculated using the weighted-average basic and diluted shares used in calculating earnings per share. The Company also uses "operating netback" and "corporate netback" as indicators of operating performance, calculated on a per boe basis.

Operating netback is calculated as average realized sales price, less royalties, operating and transportation expenses and including any realized gain or loss on derivative financial instruments. Corporate netback is calculated as operating netback plus other income, less general and administrative and interest expenses.

RECAPITALIZATION AND DESCRIPTION OF THE COMPANY

Pinecrest Energy Inc., formerly Antler Creek Energy Corp. ("ACEC") was incorporated under the Business Corporations Act (Alberta) on March 24, 2006 as a capital pool corporation. On May 25, 2009, ACEC completed its qualifying transaction by acquiring all the issued and outstanding common shares of Batoche Energy Corp. ("BEC") pursuant to a share purchase agreement dated April 30, 2009. On May 31, 2009, ACEC and BEC amalgamated.

On April 26, 2010, the Company entered into a reorganization and investment agreement, which provided for a new management team and board of directors. The present capital structure of Pinecrest is based on the recapitalization. The Company has been active since its initial recapitalization transaction and we have outlined its recent history below.

- The new management team raised total proceeds of approximately \$20.0 million. The recapitalization transaction gave the new team a public vehicle.
- On June 16, 2010 the Company announced a bought-deal private placement financing, which resulted in the Company issuing 27.7 million shares at \$1.04 per share for gross proceeds of \$28.8 million.
- On July 15, 2010 the Company announced that it had entered into three separate asset acquisitions at a total cost of \$17.9 million. The acquisitions were focused on properties in the Company's Red Earth, Alberta core focus area. The Company acquired 13,150 net acres of land located in the emerging Slave Point formation tight oil play.
- On July 21, 2010 the shareholders approved the Company's name change from Antler Creek Energy Corp., to Pinecrest Energy Inc.
- On July 22, 2010, Pinecrest announced that its 2010 capital budget would be approximately \$25 million. The budget would include the drilling of 8.25 net wells targeting high quality light oil, including 6 net horizontal Slave Point wells on the Red Earth property and 2.25 net Bakken wells in SE Saskatchewan.
- On August 17, 2010, the Company announced that it had expanded its Slave Point formation drilling inventory in the Red Earth area, to 92 net horizontal locations.
- On August 24, 2010, the Company announced a \$35.0 million bought deal financing, which resulted in the issuance of 25.0 million shares at \$1.40 per share. This financing subsequently closed on September 15, 2010.
- Pinecrest is a Calgary-based energy company whose common shares trade on the TSX Venture Exchange under the symbol "PRY".

FINANCIAL AND OPERATIONAL HIGHLIGHTS

	Three months ended July 31			Twelve months ended July 31		
	2010	2009	%Change	2010	2009	%Change
Financial (\$ except per share amounts)						
Petroleum and natural gas sales	561,351	178,855	214	1,219,663	178,855	582
Funds (used) generated by operations	(263,624)	(5,274)	(4,899)	(110,008)	(165,819)	45
Per share, basic and diluted	(\$0.00)	(\$0.00)	-	(\$0.01)	(\$0.10)	93
Net loss	788,802	9,018	8,647	1,221,192	203,850	499
Per share, basic and diluted	0.01	0.00	100	0.07	0.10	27
Capital expenditures	9,691,821	17,796	54,361	10,611,677	17,796	59,530
Asset acquisitions	17,964,841	-	100	18,079,841	-	100
Net debt and working capital surplus (deficit)	17,531,301	(40,751)	43,121	17,531,300	(40,751)	43,121
Common Shares						
Shares outstanding, end of period	85,315,774	4,000,000	2,033	85,315,774	4,000,000	2,033
Weighted average shares, basic & diluted	64,478,420	2,090,849	2,984	17,071,207	2,090,849	716
Operating						
Production						
Crude oil (bbls/d)	71	39	83	43	39	11
Natural gas (mcf/d)	20	14	50	9	14	(33)
Natural gas liquids (bbls/d)	4	2	59	1	2	(35)
Barrels of oil equivalent (boe per day)	78	43	80	46	43	6
Average realized price						
Crude oil (\$ per bbls)	82.12	66.04	24	74.98	66.04	14
Natural gas (\$ per mcf)	4.62	3.90	18	4.74	3.90	22
Natural gas liquids (\$ per bbls)	49.59	45.13	10	51.27	45.13	14
Barrels of oil equivalent (\$) (6:1)	78.24	62.71	25	72.67	62.71	16
Netback per boe (\$)						
Petroleum and natural gas sales	78.24	62.71	25	72.67	62.71	16
Royalties	8.56	8.03	7	9.20	8.03	15
Operating & transportation expenses	18.54	12.02	54	18.58	12.02	55
Operating netback	51.14	42.66	20	44.89	42.66	5

PRODUCTION

Average production in the three month Reporting Period increased 80% to 78 boe/d from 43 boe/d in the three month Comparative Period. Average production in the twelve month Reporting Period increased 6% to 46 boe/d from 43 boe/d in the twelve month Comparative Period. The Comparative Period results are effective from May 25, 2009, the date the Company completed its qualifying transaction and commenced operations.

The increases are due to the following:

- Successful drilling results in the Company's core area of southeast Saskatchewan in 2009.
- The Company's acquisition of the Red Earth #1 Properties on July 14, 2010.
- The Company's acquisition of the Loon Properties on July 14, 2010.
- The Company's acquisition of the Red Earth #2 Properties on July 15, 2010.

The Company continues to concentrate its capital spending on light oil with more than 90% of its 3 month and 12 month production being in crude oil.

	Three months ended July 31			Twelve months ended July 31		
	2010	2009	%Change	2010	2009	%Change
Crude oil (bbls/d)	71	39	83	43	39	11
Natural gas (mcf/d)	20	14	50	9	14	(33)
Natural gas liquids (bbls/d)	4	2	59	1	2	(35)
Total (boe/d) (6:1)	78	43	80	46	43	6
Crude oil (%)	91	90	4	93	90	4
Natural gas (%)	4	5	(2)	3	5	(2)
Natural gas liquids (%)	5	5	(2)	4	5	(2)
Total (%)	100	100	-	100	100	-

Production is split by the Company's main operating regions as follows:

(boe/d)	Three months ended July 31			Twelve months ended July 31		
	2010	2009	%Change	2010	2009	%Change
Southeast Saskatchewan	63	43	47	42	43	-
Red Earth Alberta	15	-	100	4	-	100
Total	78	43	80	46	43	6

Production over the last five quarters is as follows:

	Q4	Q3	Q2	Q1	Q4
	2010	2010	2010	2010	2009
Crude oil (bbls/d)	71	26	50	24	39
Natural gas (mcf/d)	20	9	4	4	14
Natural gas liquids (bbls/d)	4	1	1	1	2
Total (boe/d) (6:1)	78	27	52	25	43

REVENUE

Petroleum and natural gas revenue increased 214% to \$561,351 in the three month Reporting Period, up from \$178,854 in the three month Comparative Period. This is the result of a 152% increase in production and a 25% increase in average unit price.

Petroleum and natural gas revenue increased 582% to \$1,219,663 in the twelve month Reporting Period, up from \$178,854 in the twelve month Comparative Period and is the result of a 515% increase in production and a 16% increase in average unit price.

\$	Three months ended July 31			Twelve months ended July 31		
	2010	2009	%Change	2010	2009	%Change
Crude oil sales	536,266	168,619	218	1,176,377	168,619	598
Natural gas sales	8,662	3,505	147	15,918	3,505	354
Natural gas liquids sales	16,423	6,730	144	27,368	6,730	307
Total	561,351	178,854	214	1,219,663	178,854	582

Cash flow management is an integral part of the Company's overall business strategy. The risk exposure inherent in fluctuations in the price of crude oil and natural gas, the US/Cdn dollar exchange rate and interest rates are monitored by the Company's management and its board of directors, and hedging policies and programs are being established to mitigate these risks.

At present, the Company has not undertaken any risk management contracts or commodity price contracts, and therefore has no realized or unrealized gains or losses in the three or 12 month Reporting Periods.

REALIZED PRICES

Oil Prices

The Company's crude oil prices are based on Alberta's Edmonton light stream, adjusted for quality differentials. Realized oil price increased by 24% to \$82.12/bbl in the three month Reporting Period, up from \$66.04/bbl in the three month Comparative Period and is consistent with the increase in Edmonton benchmark price. The Company realizes only a small pricing differential from the benchmark price due to the overall high quality of the Company's Bakken light oil production in southeast Saskatchewan and its Slave Point and Granite Wash light oil production in Red Earth. The Company recorded a 14% increase in oil price to \$82.12/bbl in the twelve month Reporting Period from \$66.04/bbl in the twelve month Comparative Period, as compared to a 9% increase in the Edmonton benchmark price over the same period.

Natural Gas Prices

The Company's natural gas prices are based on the Alberta AECO reference price. Due to the high heating content of the Company's liquid-rich sweet gas production, Pinecrest receives premium pricing as compared to the AECO benchmark. Pinecrest realized an 18% increase in natural gas price of \$4.62/mcf in the three month Reporting Period, up from \$3.90/mcf in the three month Comparative Period, and a 22% increase in realized natural gas price of \$4.74/mcf in the twelve month Reporting Period, up from \$3.90/mcf in the twelve month Comparative Period. This is not consistent with the period-over-period changes in the AECO benchmark price, as the Company only received revenue for its gas in the final two months of 2009, not the entire 12 month Comparative Period. The premium to AECO the Company received in both the Reporting and Comparative Periods reflects the high heating content of the Company's sweet solution gas production conserved from its Bakken oil production in Saskatchewan.

Liquids Prices

The Company's natural gas liquids prices are based on market prices and vary depending on the mix of liquids products in the Company's production mix.

Pinecrest recorded a 10% increase in natural gas liquids price to \$49.59/bbl in the three month Reporting Period, up from \$45.13/bbl in the three month Comparative Period, and recorded a 14% increase in natural gas liquids price to \$51.27/bbl in the twelve month Reporting Period, up from \$45.13/bbl in the twelve month Comparative Period. The increase is consistent with other commodity price increases during the twelve month Comparative Period.

BOE and Benchmark Prices

Pinecrest realized a 25% increase in the overall price per boe to \$78.24 in the three month Reporting Period, up from \$62.71 in the three month Comparative Period. The Company also realized an increase of 16% in the overall price per boe to \$72.67 in the twelve month Reporting Period, up from \$62.71 in the twelve month Comparative Period. The increase is due mainly to the increase in crude oil prices.

	Three months ended July 31			Twelve months ended July 31		
	2010	2009	%Change	2010	2009	%Change
Average Realized Prices						
Crude oil (\$/bbl)	82.12	66.04	24	74.98	66.04	14
Natural gas (\$/mcf)	4.62	3.90	18	4.74	3.90	22
Natural gas liquids (\$/bbl)	49.59	45.13	10	51.27	45.13	14
Total (\$/boe)	78.24	62.71	25	72.67	62.71	16
Benchmark Prices						
Oil - Edmonton light crude (\$/bbl)	72.87	69.15	6	76.78	70.54	9
Gas - AECO natural gas (average daily spot) (\$/mmbtu)	3.67	3.11	18	3.91	4.89	(20)

ROYALTY EXPENSES

Royalties, as a percentage of petroleum and natural gas revenue, decreased to approximately 11% in the three month Reporting Period and remained at 13% in the twelve month Comparative Period. Factors affecting the Company's royalty rates are as follows:

- The Company's production in Saskatchewan is from horizontal Bakken wells which are on freehold lands. The effective royalty rate is consistent from the Prior Comparative Period to the current Reporting Period, as expected.
- The Company's current production in Alberta is primarily from Crown lands and, as it originates from previously drilled wells, does not qualify for the Alberta Governments' new drilling incentives and/or credits under the existing Alberta Royalty Framework. This has very little impact on the 2010 reported results because the property acquisitions closed mid-July 2010 and results have only been reported for 15 days to the fiscal year ended July 31, 2010.

\$	Three months ended July 31			Twelve months ended July 31		
	2010	2009	%Change	2010	2009	%Change
Crown royalties	9,046	-	100	9,046	-	100
Freehold royalties and freehold production tax	46,463	20,461	127	126,907	20,461	520
Gross overriding royalties	5,877	2,431	142	18,534	2,431	663
Total royalties	61,386	22,892	168	154,487	22,892	575
As a % of petroleum and natural gas revenue						
Crown royalties	2	-	10	1	-	10
Freehold royalties and freehold production tax	8	11	(27)	10	11	9
Gross overriding royalties	1	1	-	1	1	-
Total	11	13	(15)	13	13	-
\$ Per boe	8.56	8.03	7	9.20	8.03	15

The Company expects its royalty rate to remain low into the future as drilling is planned primarily in the Red Earth area of Alberta, which will qualify for lower royalty rates introduced by the Alberta Government in 2009. The Horizontal Oil New Well Royalty Rates provide for a maximum royalty rate of 5% on production for up to 24 month or on the first 60,000 barrels, whichever comes first (actual numbers are a function of the overall depth of the new horizontal well).

OPERATING AND TRANSPORTATION EXPENSES

Operating and transportation expenses increased to \$133,037 (\$18.54 per boe) in the three month Reporting Period, up from \$34,286 (\$12.02 per boe) in the three month Comparative Period, an increase of 288%. This increase results from a 152% increase in total production or an 80% increase in production on a per barrel basis).

Operating expenses per boe increased 55% to \$18.58 in the twelve month Reporting Period, up from \$12.02 in the twelve month Comparative Period, and is primarily due to a 488% increase in production. As well, the current 12 month Reporting period includes a full year of operations, whereas the comparative year only reflects costs for the period from May 25, 2009 to year end July 31, 2009. As Pinecrest continues to exploit its assets and increase production in southeast Saskatchewan and Red Earth Alberta, it expects that expenses per boe will decrease.

The operating costs for the current 12 month period reflect certain workover expenses on wells in southeast Saskatchewan, in addition to higher per boe costs associated with the assets acquired in the Red Earth area in July 2010.

	Three months ended July 31			Twelve months ended July 31		
	2010	2009	%Change	2010	2009	%Change
Operating expenses	133,037	34,286	288	311,782	34,286	809
\$ Per boe	18.54	12.02	54	18.58	12.02	55

GENERAL AND ADMINISTRATIVE EXPENSES

Net general and administrative expenses were \$610,065 (\$85.03 per boe) for the three month Reporting Period, compared to \$104,333 (\$36.58 per boe), an increase of 485% over the three month Comparative Period. Net general and administrative expenses were \$825,274 (\$49.17 per boe) for the twelve month Reporting Period as compared to \$305,772 (\$107.21 per boe) for the twelve month comparative period.

	Three months ended July 31			Twelve months ended July 31		
	2010	2009	%Change	2010	2009	%Change
Gross general and administrative expenses	725,097	104,333	595	940,306	305,772	208
Recoveries	(1,190)	-	-	(1,190)	-	-
Capitalized	(113,842)	-	-	(113,842)	-	-
Net general and administrative expenses	610,065	104,333	485	825,274	305,772	170
\$ Per boe	85.03	36.58	132	49.17	107.21	(54)

Total gross general and administrative expenses increased 595% to \$725,097 in the three month Reporting Period, up from \$104,333 in the three month Comparative Period, and increased 208% to \$940,306 in the twelve month Reporting Period, up from \$305,772 in the twelve month Comparative Period. The increases in both periods are due primarily to an increased level of staff to support the growth of the Company, including associated professional services, related office expenses such as computer systems and software as well as costs associated with continuous disclosure requirements of the Securities Regulator.

The Company has a policy of capitalizing costs directly attributable to new capital projects. During the three and twelve months ending July 31, 2010, the Company capitalized a total of \$113,842 to its capital projects. There were no costs capitalized in the Comparative Periods, because the company was in start-up mode and did not employ technical staff that would qualify for capitalization.

In addition, the Company capitalized a portion of its general and administrative expenses in accordance with common industry practice, whereby an operator calculates and charges overhead to each working interest partner in proportion to their ownership interest, based on 100% of capital and operating expenses incurred. Pinecrest recovered a total of \$1,190 in the three and twelve month Reporting Period, reflecting the start-up of drilling operations in southeast Saskatchewan.

Management believes that it is now prepared for significant future growth and anticipates future employee additions and other increases in general and administrative expenses will be more in line with industry benchmarks. As the Company's production base grows from its planned drilling and exploitation program in Red Earth and Southeast Saskatchewan, the Company expects to see its general and administrative costs on a boe basis decrease significantly.

INTEREST EXPENSE

Interest expense per boe decreased 79% to \$1.52 in the three month Reporting Period, down from \$7.33 in the three month Comparative Period. The decrease is due to a 152% increase in production combined with a 48% decrease in total interest expense.

Interest expense per boe decreased 75% to \$1.80 in the twelve month Reporting Period, down from \$7.33 in the twelve month Comparative Period. The decrease is due to a 488% increase in production combined with a 44% increase in total interest expense. The Company paid off its related party debt in May 2010 with proceeds raised from the recapitalization transaction.

	Three months ended July 31			Twelve months ended July 31		
	2010	2009	%Change	2010	2009	%Change
Interest	10,894	20,911	(48)	30,168	20,911	44
\$ Per boe	1.52	7.33	(79)	1.80	7.33	(75)

NETBACKS

Pinecrest defines operating netback as average realized price per boe, less royalties per boe, less operating and transportation expenses per boe, plus any realized gain or loss per boe on financial instruments. Pinecrest defines corporate netback as operating netback plus other income per boe, less general and administrative expenses per boe less interest expense per boe.

Pinecrest realized an operating netback per boe of \$51.14 in the three month Reporting Period compared to an operating netback per boe of \$42.66 for the Comparative Period. Pinecrest's operating netback per boe for the twelve month Reporting Period was \$44.89 compared to \$42.66 for the Comparative Period. Increased netbacks are primarily the result of increased commodity prices for the periods reported.

Pinecrest realized a corporate netback loss of \$35.41 per boe for the three month Reporting Period compared to a corporate netback loss of \$3.07 per boe for the Comparative Period. For the year ending July 31, 2010, Pinecrest's corporate netback loss decreased to \$6.08 per boe as compared to a loss of \$73.60 for the Comparative Period. Results for the three month Reporting Period reflect increased general and administrative costs associated with the addition of technical and professional staff necessary to execute the Company's business plan.

	Three months ended July 31			Twelve months ended July 31		
	2010	2009	%Change	2010	2009	%Change
Average realized price	78.24	62.71	25	72.67	62.71	(16)
Royalty expenses	(8.56)	(8.03)	7	(9.20)	(8.03)	15
Operating expenses	(18.54)	(12.02)	54	(18.58)	(12.02)	55
Operating netback	51.14	42.66	20	44.89	42.66	5
Other income	-	(1.72)	(100)	-	(1.72)	(100)
Net general and administrative expenses	(85.03)	(36.58)	(21)	(49.17)	(107.21)	(55)
Interest expense	(1.52)	(7.33)	(80)	(1.80)	(7.33)	(76)
Corporate netback	(35.41)	(3.07)	1,053	(6.08)	(73.60)	(92)

STOCK-BASED COMPENSATION EXPENSE

The Company has adopted an incentive stock option plan whereby options may be granted from time to time to directors, officers, employees and consultants of the Company with shares to be reserved for issuance as options not to exceed 10% of the issued and outstanding common shares. In addition, the Company granted 4,830,000 of performance warrants to various directors, officers and employees on May 21, 2010, with an expiry date of five years from date of issue.

All of the performance warrants have vested and are exercisable at \$0.50 per common share subject to certain share performance criteria being satisfied. As at July 31, 2010 all share performance criteria had been met, all warrants are exercisable; however, none have been exercised.

The fair value of the warrants granted during 2010 was estimated using the Black-Scholes option pricing model. The Company recognizes the expense over the vesting period of the warrants. The following weighted average assumptions were used to calculate stock-based compensation:

	Three months ended July 31			Twelve months ended July 31		
	2010	2009	%Change	2010	2009	%Change
Dividend yield (%)	0	0	-	0	0	-
Expected volatility (%)	50	40	25	50	40	25
Risk-free rate (%)	2.29	3.75	(39)	2.29	3.75	(39)
Expected life (years)	5	10	(50)	5	10	(50)
Vesting period (years)	2	-	100	2	-	100
Weighted average fair value per warrant/option	\$0.23	\$0.26	(12)	\$0.23	\$0.26	(12)
Number of warrants/ stock options granted	4,830,000	200,000	-	4,830,000	200,000	-

Stock-based compensation expense per boe increased to \$112.25 in the three month Reporting Period, up from \$18.00 in the three month Comparative Period. Stock-based compensation expense per boe increased to \$47.98 in the twelve month Reporting Period, up from \$18.00 in the twelve month Comparative Period. The increase in total stock-based compensation expense in the Reporting Periods is due to the granting of the performance warrants, all of which have vested at July 31, 2010, partially offset by a lower weighted average fair value per warrant/option.

	Three months ended July 31			Twelve months ended July 31		
	2010	2009	%Change	2010	2009	%Change
Stock-based compensation expense	805,296	51,328	1,469	805,296	51,328	1,469
\$ Per boe	112.25	18.00	524	47.98	18.00	167

DEPLETION, DEPRECIATION AND ACCRETION EXPENSE

Depletion and depreciation

Effective May 1, 2010, the Company changed its accounting policy for depletion and depreciation of its petroleum and natural gas assets from the declining balance method to the unit of production method. Under this method, depletion and depreciation expense is calculated using the estimated proved reserve additions, plus the associated future development capital required to recover those proved reserves, plus the cost of petroleum and natural gas properties in the full cost pool attributable to those proved reserves.

As a result of this change in policy, the charge for depletion and depreciation expense for the three month Reporting Period was a credit of \$220,651 or a credit of \$30.76 per boe, as compared to a charge of \$57.71 per boe in the three month Comparative Period. Depletion and depreciation was \$472,455 (\$28.15 per boe) for the twelve month Reporting Period as compared to \$164,594 (\$57.71 per boe) for the Comparative Period. The decrease on a per boe basis results from adding reserves at a lower cost primarily through the Company's acquisitions of relatively long-life high netback properties, as compared to the Comparative Periods. The increase in total depletion and depreciation expenses reflect higher total production in the Reporting Periods. At July 31, 2010, the Company excluded from its full cost pool \$25,297,073 (2009 - \$154,598) of costs for undeveloped land acquired at Crown land sales and through acquisitions during the year.

Accretion Expense

Pinecrest records its asset retirement obligations as the present value of the estimated abandonment and reclamation costs for its well sites, pipelines and facilities. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Accretion expense per boe decreased to \$0.13 in the three month Reporting Period, down from \$0.20 in the three month Comparative Period, primarily as the result of increased production in the three month Reporting Period.

Accretion expense per boe increased to \$0.26 in the twelve month Reporting Period, up from \$0.20 in the twelve month Comparative Period.

	Three months ended July 31			Twelve months ended July 31		
	2010	2009	%Change	2010	2009	%Change
Depletion and depreciation expense	(220,651)	164,594	(234)	472,455	164,594	187
\$ Per boe	(30.76)	57.71	(153)	28.15	57.71	(51)
Accretion expense	930	581	60	4,282	581	637
\$ Per boe	0.13	0.20	(36)	0.26	0.20	25
Total depletion, depreciation and accretion expense	(219,721)	165,175	233	476,737	165,175	189
\$ Per boe	(30.63)	57.91	(153)	28.41	57.91	(51)

INCOME AND OTHER TAXES

Pinecrest recorded a future income tax recovery of \$60,395 in the three month Reporting Period, offset by a current income tax expense of \$8,508 compared to a future income tax recovery of \$212,759 for the three month Comparative Period. The Company recorded a future income tax recovery of \$170,849 in the twelve month Reporting Period, compared to a future income tax recovery of \$212,759 for the twelve month Comparative Period. The recoveries result mainly from recognition of the tax benefit from non-capital losses, and reductions to future corporate income tax rates.

NET EARNINGS AND CASH FLOW

The Company recorded a net loss of \$788,602 or \$0.01 per basic and diluted share in the three month Reporting Period, as compared to a net loss of \$9,018 or \$0.00 per basic and diluted share in the three month Comparative Period, representing a 100% decrease in losses on a per share basis. The Company recorded a net loss of \$1,221,192 or \$0.07 per basic and diluted share in the twelve month Reporting Period, as compared to a net loss of \$203,849 or \$0.10 per basic and diluted share in the twelve month Comparative Period, representing a 27% decrease in losses on a per share basis.

The net loss for the twelve month Reporting Period reflects the costs associated with the start-up and hiring of a full complement of technical and professional staff required to execute the Company's current business plan.

The Company recorded a cash flow deficit from operations of \$263,623 or \$0.00 per basic and diluted share in the three month Reporting Period, as compared to a cash flow deficit of \$5,273 or \$0.00 per basic and diluted share in the three month Comparative Period, representing no change in cash flow per basic and diluted share. The Company recorded cash flow deficit from operations of \$110,008 or \$0.01 per basic and diluted share in the twelve month Reporting Period, as compared to cash flow deficit of \$200,105 or \$0.10 per basic and diluted share in the twelve month Comparative Period, representing an increase of \$0.09 per basic and diluted share.

CAPITAL EXPENDITURES AND CAPITAL RESOURCES

Capital expenditures totaled \$28,691,571 in 2010 compared to \$17,796 in 2009. The increase in spending was incurred primarily on undeveloped land in the Red Earth area of Alberta and on three property acquisitions in the Greater Red Earth area that closed in mid-July.

Capital Expenditures

During the Reporting Periods, Pinecrest focused its capital spending primarily on property acquisitions in Red Earth with the intention of adding to its land base and to increase its drilling inventory.

	Three months ended July 31			Twelve months ended July 31		
	2010	2009	%Change	2010	2009	%Change
Land acquisition	9,374,347	-	100	9,379,323	-	100
Drilling and completions	32,094	17,796	80	801,344	17,796	4403
Equipment and facilities	26,299	-	100	171,929	-	100
Property acquisitions Capitalized	17,964,841	-	100	18,079,841	-	100
administration	113,842	-	100	113,842	-	100
Office and other	145,239	-	100	145,239	-	100
Total capital expenditures	27,656,662	17,796	155,309	28,691,518	17,796	161,124

Pinecrest is committed to fulfill the flow-through obligations pursuant to its May 7, 2010 private placement of flow-through shares. Pinecrest has until December 31, 2011 to incur the full \$5,011,750 of qualifying and development expenditures. At July 31, 2010, Pinecrest had incurred approximately \$40,000 of its qualifying expenditures, leaving approximately \$4,971,750 to be spent by December 31, 2011. Given management's capital budget for the remainder of 2010, the Company expects to complete its obligation by December 2010.

In July 2010, Pinecrest's Board of Directors approved a \$25.0 million budget for the remainder of 2010. The capital program will focus on Bakken and Red Earth light oil development drilling and completions. This budget includes the expected drilling of 8.25 net oil wells, 2.25 of which are in Southeast Saskatchewan and 6 are in Red Earth, Alberta.

Drilling Results

Pinecrest participated in two (0.4 net) wells that were drilled in the southeast Saskatchewan Bakken formation that were subsequently tied-in and brought onto production in early 2010. In addition, Pinecrest started construction on two additional wells in southeast Saskatchewan that were spudded in early August 2010.

	Three months ended July 31				Twelve months ended July 31			
	2010		2009		2010		2009	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Crude oil	-	-	-	-	2	0.4	-	-
Natural gas	-	-	-	-	-	-	-	-
Standing	-	-	-	-	-	-	-	-
Dry and abandoned	-	-	-	-	-	-	-	-
Total	-	-	-	-	2	0.4	-	-
Success rate (%)	n/a	n/a	-	-	100	100	-	-

LIQUIDITY AND CAPITAL RESOURCES

The Company had a combined cash and working capital surplus of \$17,531,301 at July 31, 2010 as compared to a working capital deficit of \$40,751 at July 31, 2009. The 431% improvement in the debt and working capital deficiency results mainly from the Company's equity financings which were completed in May, 2010 and July 2010. The May 2010 financing resulted in the issuance of 53.0 million common shares at a price of \$0.375 per share for total gross proceeds of \$19.9 million. The Company issued 24.1 million common shares at \$1.04 per share in a bought-deal financing, for gross proceeds of \$28,793,800. This financing closed July 7, 2010.

On September 15, 2010, the Company closed another bought deal financing in which it issued 25.0 million shares at \$1.40 per share for gross proceeds of \$35,000,000. Presently, the Company has a debt and working capital surplus in excess of \$40 million.

Management anticipates that the Company will continue to have adequate liquidity to fund future working capital requirements and capital expenditures through combination of cash flows, cash on hand, the availability of credit facilities and additional equity investment. The Company's capital program scheduled for 2010 calls for capital expenditures of approximately \$25.0 million which will be financed from cash flow from operations and cash on hand.

SHARE CAPITAL

The Company had the following outstanding common shares for the Reporting and Comparative Periods:

	Three months ended July 31		Twelve months ended July 31	
	2010	2009	2010	2009
Weighted Average Outstanding Common Shares				
Basic	64,478,420	4,000,000	17,071,207	2,090,849
Diluted	64,478,420	4,000,000	17,071,207	2,090,849
Outstanding securities at July 31, 2010				
Common Shares				85,315,774
Common Share Purchase Warrants				29,928,930
Performance Warrants				4,830,000

Total Market Capitalization

The Company's market capitalization at July 31, 2010 was approximately \$171,706,827.

	July 31, 2010
Common shares – fully diluted	120,074,704
Share price (1)	\$1.43

(1) Represent the last price traded on the Toronto Stock Exchange (Venture) July 31, 2010

At October 5, 2010 there were 110,315,774 common shares outstanding, 29,928,930 common share purchase warrants outstanding, and 4,830,000 performance warrants outstanding.

PINECREST OUTLOOK

The Company expects to be very active operationally for the remainder of 2010 and into the future. In July 2010, Pinecrest's Board of Directors approved a \$25.0 million capital budget up to December 31, 2010, with a continued focus on Bakken and Slave Point light oil development drilling. This budget includes the expected drilling of 8.25 net oil wells, 2.25 of which are in southeast Saskatchewan and 6 of which are in the Red Earth Area. There have also been funds allocated for additional land purchases and facilities.

Presently the Company has not prepared a budget for fiscal 2011 but with its strong balance sheet and land position, the growth and exploitation in Red Earth and southeast Saskatchewan is expected to continue.

NEWLY ADOPTED ACCOUNTING POLICIES**Petroleum and Natural Gas Properties and Depletion**

On May 1, 2010, the Company voluntarily changed its accounting policy for petroleum and natural gas properties and equipment from the successful efforts method to the full cost method. In addition the Company changed its accounting policy for depletion of its petroleum and natural gas properties from the declining balance method of depletion to the unit-of-production method. These changes in accounting policies will provide reliable and more relevant reporting for the Company's oil and gas operations. The majority of junior oil and gas producers use the full cost method to account for their oil and gas properties and this will enable the Company to provide financial reporting which will be more comparable to its industry peers. In addition the change to unit-of-production method of depletion provides more relevant information about the consumption of the petroleum and natural gas reserves of the Company.

There is no impact to the financial statements resulting from the change to full cost accounting because the Company did not have any dry holes, or any direct general and administrative costs which could be directly attributable, and thus capitalized under the full-cost method, to its petroleum and natural gas properties and equipment prior to May 2009. Therefore the only impact that these accounting policy changes have on the financial statements is the amount of depletion and related future income taxes associated with the change in net book values of the Company's petroleum and natural gas assets. These policy changes were applied retrospectively. See Note 2 to the audited annual financial statements.

Section 3862 Financial Instrument- Disclosures

The Canadian Accounting Standards Board (“AcSB”) made amendments to Section 3862 *Financial Instruments - Disclosures* to improve disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three-level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. The amendments to Section 3862 apply for annual financial statements relating to fiscal years ending after September 30, 2009 and are consistent with recent amendments to financial instrument disclosure standards under International Financial Reporting Standards (“IFRS”). The Company adopted this new standard effective August 1, 2009, for the year end July 31, 2010. The adoption of this standard did not have any impact on the Company’s financial statements because the Company does not have any financial instruments that are revalued to fair value on a recurring basis.

EIC – 173 Credit Risk and the Fair Value of Financial Assets

Effective August 1, 2009, the Company adopted the CICA Emerging Issues Committee (“EIC”) Abstract No. 173, Credit Risk and the Fair Value of Financial Assets and Financial Liabilities. (“EIC 173”) which clarified that an entity must consider its own credit risk and the credit risk of the counterparty when measuring the fair value of derivative instruments.

Section 3855 Financial Instruments – Recognition and Measurement

Effective August 1, 2009, the Company adopted the amendments to Section 3855. These amendments bring greater consistency between Canadian GAAP, International Financial Reporting Standards (“IFRS”) and US GAAP regarding the timing of impairment recognition for debt instruments. The amendments allow more debt instruments to be classified as loans and receivables. In addition, the amendments require reversal of previously recognized impairment losses on available-for-sale financial assets in specified circumstances and require that loans and receivables that an entity intends to sell immediately or in the near term be classified as held for trading. The adoption of this standard did not have any impact on the financial statements.

Section 3064 Goodwill and Intangible Assets

This Section establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The adoption of this new standard did not have any impact on the financial statements of the Company.

FUTURE ACCOUNTING PRONOUNCEMENTS

International Financial Reporting Standards (“IFRS”)

In February 2008, the AcSB confirmed the convergence of Canadian GAAP with International Financial Reporting Standards (“IFRS”) will be required for interim and annual financial Statements effective for fiscal years beginning on or after January 1, 2011, including comparatives for 2010 and an opening balance sheet at January 1, 2010 showing the changes from Canadian GAAP to IFRS. For Pinecrest, the date of transition will be August 1, 2011.

IFRS uses a conceptual framework similar to Canadian GAAP however IFRS prescribes certain differences for recognition, measurement and disclosure principles which are outlined below under “*Potential Impacts of IFRS Adoption*”.

IFRS Transition Project

Pinecrest has recently commenced its IFRS Conversion Plan, which will include training and development through-out the organization. The three phases of the plan are: Scoping and Diagnostic, Design and Evaluation and Implementation.

IFRS Conversion Project Phase	Progress
Phase 1 Scoping and Diagnostic Identification of key differences between Canadian GAAP and IFRS, and high-level changes required in accounting policies, systems and processes.	In progress; the IFRS Team has been identified and preliminary review of high impact standards has been completed.
Phase 2 Design and Evaluation Comprehensive documentation and analysis of changes in accounting standards, policies, processes and procedures, which expands on scoping from Phase 1	Initiated; the IFRS Team has set up monthly process which take into consideration the differences in policy as identified in Phase 1. Detailed discussion and review with the Audit Committee has not been done yet.
Phase 3 – Implementation Implementation and execution of changes identified and prioritized from Phase 2.	Not started.

Potential Impacts of IFRS Adoption

The following have been identified as differences between Canadian GAAP and IFRS that will impact Pinecrest: accounting for capital assets, including exploration costs, depletion and depreciation, impairment testing, asset retirement obligations, share-based payments and an increased level of disclosure requirements. These differences have been identified based on current IFRS standards issued and expected to be in effect on the date of transition. Certain IFRS standards may be modified, and as a result, the impact may be different than the Company's current expectations. The project team is currently determining the financial statement impact of these standards.

The following is a summary of the identified IFRS standards that will have an impact on the Company's financial statements:

- a) **First Time Adoption of IFRS ("IFRS 1"):** The transition to IFRS requires the Company to apply IFRS 1, which prescribes requirements for preparing IFRS-compliant financial statements in the first reporting period after the changeover date (January 1, 2010). IFRS 1 includes a requirement for retrospective application of each IFRS as if they were always in effect. IFRS 1 also mandates certain exemptions for retrospective application and provides optional exemptions from retrospective application to ease the transition to IFRS in the transition year.

In July 2009, the International Accounting Standards Board approved amendments and released additional exemptions to IFRS 1 "Additional Exemptions for First-time Adopters" which prescribes transitional exemptions for oil and gas companies following full cost accounting. The amendment allows an entity that used full cost accounting under its previous GAAP to elect, at its time of adoption, to measure exploration and evaluation assets at the amount determined under the entity's previous GAAP and to measure oil and natural gas assets in the development or production phases by allocating the amount determined under the entity's previous GAAP for those assets, to the underlying assets pro rata using reserve volumes or reserve values as of the date of transition, subject to an impairment test as prescribed under IFRS. This exemption will allow Pinecrest to apply IFRS to its full cost pools on a prospective basis, from date of transition to IFRS.

- b) **Impairment of Assets ("IAS 36"):** IAS 36 uses the concept of cash generating units to accumulate asset carrying costs to test and measure impairment. Under IFRS, Pinecrest will no longer be permitted to test for asset impairment at the cost center level (country level) as permitted under Canadian GAAP full cost guideline. IFRS will require impairment testing to be performed at the cash generating unit level, which is at a lower level than the current cost center level.

In addition, IAS 36 uses a one-step approach for testing and measuring asset impairments, with asset carrying values being compared to the higher of: value-in-use and fair value less costs to sell. Value in use is defined as the amount equal to the present value of future cash flows expected to be derived from the asset. In the absence of an active market, fair value less costs to sell may also be determined using discounted cash flows. The use of discounted cash flows under IFRS to test and measure asset impairment differs from Canadian GAAP, which uses undiscounted cash flows. This may result in more frequent write-downs in the carrying amounts of assets under IFRS because the asset carrying amounts previously supported under Canadian GAAP were based on undiscounted cash flows.

However, under IAS 36, impairment losses that were previously recognized may be reversed where circumstances change such that the impairment is reduced. This differs from Canadian GAAP, which prohibits the reversal of previously recognized impairment losses.

- c) **Exploration and Evaluation Expenditures ("IFRS 6"):** Oil and gas companies are required to account for exploration and evaluation expenditures in accordance with IFRS 6, which permits a number of accounting policy choices. For example, this standard addresses the recognition, measurement, presentation and disclosure requirements for costs incurred in the exploration phase.

Unlike Canadian GAAP, IFRS requires the identification and presentation of exploration and evaluation expenditures to be separated from developed and producing assets. In addition, Pinecrest will be required to perform an impairment test on exploration and evaluation expenditures when there is a determination that the expenditures have resulted in a technically feasible and commercially viable project. At that time, the expenditures would be tested for impairment, and then transferred to the developed and producing assets category. Pinecrest is currently evaluating its policy options and applicable impact of these policies under IFRS.

- d) **Property Plant and Equipment (“IAS 16”)**: IFRS and Canadian GAAP contain the same basic principles of accounting for property, plant and equipment; however, differences in application do exist, specifically for oil and gas companies. IAS 16 requires costs recognized as property plant and equipment to be allocated to the significant parts of the asset and amortize each significant component separately. This is a departure from Canadian GAAP for full cost oil and gas companies, and may increase the number of components that will be amortized separately, and could impact the amount of amortization expense. Pinecrest is currently assessing the number of components that will be identified for amortization purposes.

Under IAS 16, companies have the choice to account for property, plant and equipment under the cost model, or the revaluation model. It is expected that Pinecrest will choose and apply the cost model to account for its property, plant and equipment after transition to IFRS.

- e) **Decommissioning Costs (“IAS 37”)**: Under IFRS, the recognition criteria for contingent liabilities are much more explicit than Canadian GAAP and may potentially require the booking of additional liabilities associated with the asset retirement obligations of Pinecrest's oil and gas assets. Liabilities for decommissioning and restoration are recognized for both legal and constructive obligations. Under IFRS, the estimated liability is calculated at each reporting period using estimates of risk-adjusted future cash outflows, discounted using the risk free rate whereas under Canadian GAAP the estimated liability is estimated using a credit-adjusted rate, rather than a risk free rate.

Changes in the estimated timing of cash flows necessary to discharge the obligation are added to or deducted from the cost of the related asset and the adjusted amounts are amortized prospectively over the estimated useful life of the asset. The measurement of the present value of the estimate (arising due to different discount rates used) is likely to be higher under IFRS as compared to Canadian GAAP. However the difference, if any, is not known at this time. In addition, the unwinding of the discount arising from the passage of time is recognized as a financing cost and not a part of depletion expense as is currently presented in the Company's' financial statements under Canadian GAAP.

- f) **Share based Payments (IFRS 2): Similar to Canadian GAAP**, share-based payments under IFRS require that the expense be measured at fair value. However, IFRS requires the expense related to share-based payments to be recognized as the options or warrants vest.

Each tranche of options or warrants is to be treated as a separate grant, which will accelerate the expense recognition as compared to Canadian GAAP, which permits the recognition of the expense on a straight-in basis over the period that the options/warrants vest. Under IFRS the expense recognition will be accelerated, but the cumulative expense over the life of the instruments under both methods will be the same.

Internal Controls over Financial Reporting and Disclosure

Pinecrest management intends to review all entity level, information technology; disclosure and business process controls and will update and test, as required, to reflect changes arising from Pinecrest conversion to IFRS. Material changes identified will be mapped and tested to ensure that no material deficiencies exist as a result of the conversion to IFRS.

Information Systems

It is expected that the conversion to IFRS will have an impact on the information system requirements. Pinecrest has evaluated its financial reporting system and determined that it will be able to accommodate dual reporting during the transition year.

CRITICAL ACCOUNTING ESTIMATES

Pinecrest's financial statements have been prepared in accordance with Canadian generally accepted accounting principles. Certain accounting policies require management to make decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses.

Pinecrest's management reviews its estimates frequently; however, the emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. Pinecrest attempts to mitigate this risk by employing individuals with the appropriate skill set and knowledge to make reasonable estimates, developing internal control systems and comparing past estimates to actual results.

The Company's financial and operating results include estimates of the following:

- Depletion, depreciation and accretion and the ceiling test (test for impairment) are based on estimates of crude oil and natural gas reserves;
- Revenues, operating expenses and royalties for which accruals have been recorded for actual revenues and costs which have been earned or incurred but have not yet been received;
- Capital expenditures on projects that are in progress;
- Asset retirement obligations including estimates of future costs and the timing of the costs.

RISK FACTORS

Statements in this document may contain forward-looking information including expectations of future production, components of cash flow and earnings, expected future events and/or financial results that are forward-looking in nature and subject to substantial risks and uncertainties. The reader is cautioned that assumptions used in the preparation of such information may prove to be incorrect. The Company cautions the readers that actual performance will be affected by a number of factors, many of which may respond to changes in economic and political circumstances throughout the world. Events or circumstances may cause actual results to differ materially from those predicted, a result of numerous known and unknown risks, uncertainties, and other factors, many of which are beyond the control of the Company. These risks include, but are not limited to, the risks associated with the oil and gas industry, and changes to commodity prices and interest and foreign exchange rates.

Industry related risks could include, but are not limited to, operational risks in exploration, development and production, delays or changes in plans, risks associated with the uncertainty of reserve estimates, health and safety risks and the uncertainty of estimates and projections of production, costs and expenses. These external factors beyond the Company's control may affect the marketability of oil and natural gas produced, industry conditions including changes in laws and regulations, changes in income tax regulations, increased competition, fluctuations in commodity prices, interest rates, and variations in the Canadian/United States dollar exchange rate. The reader is cautioned not to place undue reliance on this forward-looking information.

Pinecrest's production and exploration activities are concentrated in the Western Canadian Sedimentary Basin, where activity is highly competitive and includes a variety of different sized companies ranging from smaller junior producers to the much larger integrated petroleum companies. Pinecrest is subject to the various types of business risks and uncertainties including:

- Finding and developing oil and natural gas reserves at economic costs;
- Production of oil and natural gas in commercial quantities; and
- Marketability of oil and natural gas produced.

In order to reduce exploration risk, the Company strives to employ highly qualified and motivated professional employees with demonstrated ability to generate quality proprietary geological and geophysical prospects. To help maximize drilling success, Pinecrest combines exploration in areas that afford multi-zone prospect potential, targeting a range of low to moderate risk prospects with some exposure to select high-risk plays with high-reward opportunities. Pinecrest also explores in areas where the Company's officers and employees have significant drilling and completions experience.

The Company mitigates its risk related to producing hydrocarbons through the utilization of the most appropriate technology and information systems. In addition, Pinecrest seeks operational control of its projects, where feasible. Oil and gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. In order to mitigate such risks, Pinecrest conducts its operations at high standards and follows safety procedures intended to reduce the potential for personal injury to employees, contractors and the public at large. The Company maintains current insurance coverage for general and comprehensive liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect changing corporate requirements, as well as industry standards and government regulations.

INTERNAL CONTROLS

Disclosure Controls and Procedures

The Company has established disclosure controls and procedures for the timely and accurate preparation of financial and other reports. Disclosure controls and procedures are designed to provide reasonable assurance that material information required to be disclosed is recorded, processed, summarized and reported within the time periods specified by applicable securities regulations and that information required to be disclosed is accumulated and communicated to the appropriate members of management for proper reflection in the Company's filings.

Management maintains a system of internal controls to assure that the Company's assets are safeguarded, transactions are authorized and financial information is complete and reliable. Management's review of its internal controls led it to conclude that the internal controls are effective in ensuring the reliability of the financial information for the year ended July 31, 2010. The Company has a limited number of employees therefore internal controls that rely on segregation of duties are not possible in many cases. In these instances, the Company relies on senior management review and approval to ensure that the controls are as effective as possible.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected the disclosure and internal controls and procedures will prevent all errors or fraud.

RELATED PARTY TRANSACTIONS

The Company entered into a loan agreement for \$1,100,000 on May 22, 2009, bearing interest at 4% per annum, with a related party, who was a shareholder, director and officer of the Company, as part consideration for the acquisition of Batoche Energy Corp. The Company paid the balance of the loan \$998,099 and interest of \$30,168 (2009 - \$20,911) during the Reporting Period.

General and administrative expenses for the Reporting Period include legal expenses of \$187,764 (2009- \$207,660) and rent expenses of \$25,714 (2009 - \$5,859) paid to a company that was related by virtue of a common shareholder who was previously a director, officer and shareholder of the Company. Accounts payable and accrued liabilities include \$nil (2009- \$7,850) related to these transactions.

The Company incurred legal fees of \$298,344 (2009- \$nil) related to equity financings, to a law firm, of which of a current board member is a partner. A total of \$86,966 (2009 - \$nil) was outstanding at July 31, 2010.

SUBSEQUENT EVENTS

On August 24, 2010 the Company announced that it has entered into an agreement with a syndicate of underwriters to issue on a bought deal basis 25,000,000 common shares ("Common Shares") at a price of \$1.40 per Common Share for aggregate gross proceeds of approximately \$35,000,000. Closing occurred on September 15, 2010.

The Company has also granted the underwriters an option (the "Over-Allotment Option") to purchase up to an additional 3,750,000 Common Shares to cover over allotments, if any, at a price of \$1.40 per Common Share for additional gross proceeds of approximately \$5,250,000. The Over-Allotment Option is exercisable in whole or in part for a period of 30 days following the closing of the offering.

OFF BALANCE SHEET ARRANGEMENTS

The Company has not entered into any off balance sheet arrangements.

ADDITIONAL INFORMATION

Additional information may be obtained by contacting the Company at Pinecrest Energy Inc. Suite 500, 255 5th Avenue SW, Calgary, Alberta, T2P 3G6, or on-line at www.SEDAR.com