ASPEN EXPLORATION CORP
Form 10QSB
May 15, 2007

FORM 10-QSB

SECURITIES AND EXCHANGE COMMISSION

Washington D.C. 20549

MARK ONE

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2007

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ________ to ________

Commission File Number 0-9494

ASPEN EXPLORATION CORPORATION
(Exact Name of Aspen as Specified in its Charter)

Delaware	84-0811316
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
Suite 208, 2050 S. Oneida St., Denver, Colorado	80224-2426
(Address of Principal Executive Offices)	(Zip Code)

Issuer's telephone number: (303) 639-9860

Indicate by check mark whether Aspen (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that Aspen was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [X] No [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes [ ] No [X]

Indicate the number of shares outstanding of each of the Issuer's classes of common stock as of the latest practicable date.

Class	Outstanding at May 14, 2007
Common stock, $.005 par value	7,259,622

Transitional small business disclosure format: Yes -- XX No --

Part One. FINANCIAL INFORMATION

Item 1. FINANCIAL STATEMENTS

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2007 (unaudited)	June 20
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 3,179,469	$ 6,4
Short-term investments	1,074,937	1,0
Accounts and trade receivables	2,562,363	2,1
Accounts receivable - related party	1,273	
Other current assets	56,452	3
Total Current Assets	6,874,494	9,9
Property and equipment		
Oil and gas property (full cost method)	18,592,790	14,2
Support equipment	184,514	1
	18,777,304	14,3
Accumulated depletion and impairment - full cost pool	(7,615,883)	(6,1
Accumulated depreciation - support equipment	(43,840)	(
Net property and equipment	11,117,581	8,2
Other assets:		
Deposits	263,650	2
Deferred income taxes	1,482,500	7
Total other assets	1,746,150	1,0
Total Assets	$ 19,738,225	$ 19,1

(Statement Continues)

The accompanying notes are an integral part of these condensed consolidated financial stat

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

	March 31, 2007 (unaudited)
LIABILITIES AND STOCKHOLDERS' EQUITY	
Current Liabilities:	
Accounts payable	$ 2,510,585
Other current liabilities and accrued expenses	1,089,485
Notes payable - current portion	275,004
Asset retirement obligation, current portion	28,000
Total Current Liabilities	3,903,074
Long-term liabilities	
Notes payable, net of current portion	660,412
Asset retirement obligation, net of current portion	531,280
Deferred income taxes	3,609,000
Total Long-Term Liabilities	4,800,692
Stockholders' Equity:	
Common stock, $.005 par value: Authorized: 50,000,000 shares Issued and outstanding: At March 31, 2007, 7,159,622 shares and June 30, 2006, 7,094,641 shares	35,723
Capital in excess of par value	7,421,172
Retained earnings	3,577,564
Deferred compensation	--
Total Stockholders' Equity	11,034,459
Total Liabilities and Stockholders' Equity	$ 19,738,225

The accompanying notes are an integral part of these condensed consolidated financial s

3

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended March 31,	Nine Mo M

	2007	2006	2007
Revenues:			
Oil and gas sales	$ 1,344,791	$ 1,496,427	$ 3,361,563
Management fees	154,876	92,682	386,818
Total Revenues	1,499,667	1,589,109	3,748,381
Expenses:			
Oil and gas production	247,292	164,796	576,534
Accretion, and depreciation, depletion and amortization	548,176	450,000	1,528,330
Selling, general and administrative	266,728	205,592	1,047,065
Total Operating Expenses	1,062,196	820,388	3,151,929
Income from Operations	437,471	768,721	596,452
Other Income (Expenses)			
Interest and other income	8,422	23,612	44,308
Interest and other expenses	(10,948)	(22)	(15,716)
Gain on investments	194,400	--	685,096
Gain on sale of equipment	--	--	12,000
Total Other Income (Expenses)	191,874	23,590	725,688
Income Before Income Taxes	629,345	792,311	1,322,140
Provision for Income Taxes	(212,393)	(361,955)	(287,393)
Net Income	$ 416,952	$ 430,356	$ 1,034,747
Basic Net Income Per Share	$ 0.06	$ 0.06	$ 0.14
Diluted Net Income Per Share	$ 0.06	$ 0.06	$ 0.14
Dividends Per Share	$ --	$ --	$ 0.05
Weighted Average Number of Common Shares Outstanding:			
Basic	7,149,735	6,775,715	7,149,735
Diluted	7,326,684	7,360,966	7,326,684

The accompanying notes are an integral part of these condensed consolidated financial st

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Nine Months End
	2007
Cash Flows from Operating Activities:	
Net income	$ 1,034,747
Adjustments to reconcile net income to net cash provided by operating activities:	
Accretion and depreciation, depletion, and amortization	1,528,330
Deferred income taxes	212,500
Amortization of deferred compensation	119,233
Compensation expense related to stock options granted	109,008
Realized (gain) on investments	(373,869)
(Gain) on sale of vehicle	(12,000)
Unrealized (gain) on investments	(311,227)
Proceeds from sale of investments	612,686
Changes in assets and liabilities:	
Increase in current assets other than cash, cash equivalents, and short-term investments	(155,884)
Increase (decrease) in liabilities other than notes payable	(2,410,375)
Net Cash Provided by Operating Activities	353,149
Cash Flows from Investing Activities:	
Additions to oil and gas properties	(2,718,200)
Producing oil and gas properties purchased	(1,075,000)
Additions to property and equipment	(89,425)
Sale of property and equipment	12,000
Net Cash (Used) in Investing Activities	(3,870,625)
Cash Flows from Financing Activities:	
Proceeds from exercise of stock options	28,500
Proceeds from issuance of common stock	--
Proceeds from issuance of long-term debt	600,000
Payment of long-term debt	(39,584)
Payment of cash dividends	(357,981)
Net Cash Provided by Financing Activities	230,935
Net Increase/(Decrease) in Cash and Cash Equivalents	(3,286,541)
Cash and Cash Equivalents, beginning of year	6,466,010

Cash and Cash Equivalents, end of year	$ 3,179,469
Other Information:	
Interest paid	$ 15,716
Income taxes paid	$ 800
Non-Cash Investing and Financing Activities:	
Asset retirement obligation	$ 149,948
Notes payable assumed	$ 375,000
Stock issued for deferred consulting services	$ --

The accompanying notes are an integral part of these condensed consolidated financial sta

ASPEN EXPLORATION CORPORATION

Notes to Condensed Consolidated Financial Statements
(Unaudited)
March 31, 2007

NOTE 1 - BASIS OF PRESENTATION

The accompanying condensed consolidated financial statements of Aspen Exploration Corporation (the Company) are unaudited. However, in the opinion of management, the accompanying condensed consolidated financial statements reflect all adjustments, consisting of only normal recurring adjustments, necessary for fair presentation for the interim period.

The consolidated financial statements included herein have been prepared by the Company pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and footnote disclosures normally included in consolidated financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted pursuant to such rules and regulations. Management believes the disclosures made are adequate to make the information not misleading and suggests that these condensed consolidated financial statements be read in conjunction with the consolidated financial statements and notes hereto included in the Company's Form 10-KSB for the year ended June 30, 2006.

This Form 10-QSB includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical fact included in this Form 10-QSB, including, without limitation, the statements under both "Notes to Consolidated Financial Statements" and "Item 2. Management's Discussion and Analysis" located elsewhere herein regarding the Company's financial position and liquidity, its strategies, financial instruments, and other matters, are forward-looking statements. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from the Company's expectations are disclosed in this Form 10-QSB in conjunction with the forward-looking statements.

NOTE 2 - SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. The Company bases its estimates on historical experience and on various other assumptions it believes to be reasonable under the circumstances. Although actual results may differ from these estimates under different assumptions or conditions, the Company believes that its estimates are reasonable and that actual results will not vary significantly from the estimated amounts.

Recent Accounting Pronouncements

In June 2006, the FASB issued Interpretation (FIN) No. 48, Accounting for Uncertainty in Income Taxes--an interpretation of FASB Statement No. 109. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return, and provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. This Interpretation is effective for fiscal years beginning after December 15, 2006. The Company is currently assessing the potential impact of this Interpretation on its financial statements.

In September 2006, Statement of Financial Accounting Standards (SFAS) No. 157, Fair Value Measurements was issued by the Financial Accounting Standards Board (FASB). This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 will become effective for the Company's fiscal year beginning after November 15, 2007, and the Company is currently assessing the potential impact of this Statement on its financial statements.

In September 2006, Staff Accounting Bulletin ("SAB") No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements. Registrants must quantify the impact on current period financial statements of correcting all misstatements, including both those occurring in the current period and the effect of reversing those that have accumulated from prior periods. This SAB will be applied beginning with the first fiscal year ending after November 15, 2006. The adoption of SAB No. 108 should have no effect to the financial position and result of operations of the Company.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, which permits an entity to measure certain financial assets and financial liabilities at fair value. The objective of SFAS No. 159 is to improve financial reporting by allowing entities to mitigate volatility in reported earnings caused by the measurement of related assets and liabilities using different attributes, without having to apply complex hedge accounting provisions. Under SFAS No. 159, entities that elect the fair value option (by instrument) will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option election is irrevocable, unless a new election date occurs. SFAS No. 159 establishes presentation and disclosure requirements to help financial statement users understand the effect of the entity's election on its earnings, but does not eliminate disclosure requirements of other accounting standards. Assets and liabilities that are measured at fair value must be displayed on the face of the balance sheet. This statement is effective beginning January 1, 2008 and we are evaluating this pronouncement.

NOTE 3 - SHARE-BASED COMPENSATION

Stock Options

Effective July 1, 2006, the Company adopted the fair value recognition provisions of Statement of Financial Accounting Standard 123(R) "Share-Based Payment" ("SFAS 123(R)") using the modified prospective transition method. In addition, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 107 "Share-Based Payment" ("SAB 107") in March, 2005, which provides supplemental SFAS 123(R) application guidance based on the views of the SEC. Under the modified prospective transition method, compensation cost recognized in the quarterly and year-to-date periods ended March 31, 2007 include: (a) compensation cost for all share-based payments granted prior to, but not yet vested as of July 1, 2006, based on the grant date fair value estimated in accordance with the original provisions of SFAS No. 123, and (b) compensation cost for all share-based payments granted beginning July 1, 2006, based on the grant date fair value estimated in accordance with the provisions of SFAS 123(R). In accordance with the modified prospective transition method, results for prior periods have not been restated.

NOTE 3 - SHARE-BASED COMPENSATION (Continued)

The Company currently has two share-based employee compensation plans, which are described in the Notes to Consolidated Financial Statements in the Company's Annual Report on Form 10-KSB for the year ended June 30, 2006.

There was an aggregate of 936,000 common shares reserved for issuance under our stock option plans effective at April 22, 2005, and March 14, 2002. These plans provided for the issuance of 260,000 and 676,000 common shares, respectively, pursuant to stock option exercises. The fair value of each option grant, as opposed to its exercise price, is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions: no dividend yield, expected volatility of 76%, risk free interest rates of 3.92% and expected lives of 4.5 years. Expected volatility was calculated based upon actual historical stock price movements over the most recent periods ending June 30, 2006 equal to the expected option term. Expected pre-vesting forfeitures were assumed to be zero. The expected option term was calculated using the "simplified" method permitted by SAB 107.

The adoption of SFAS 123(R) resulted in stock compensation expense for the three and nine months ended March 31, 2007 of $27,500, and $109,008, respectively, to income from continuing operations and income before income taxes. This expense did not have a significant effect on diluted earnings per share for the quarter, or year-to-date periods ended March 31, 2007.

Prior to July 1, 2006, the Company accounted for these plans under the recognition and measurement provisions of Accounting Principles Board ("APB") Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations, as permitted by Statement of Financial Accounting Standards ("SFAS") No. 123, Accounting for Stock-Based Compensation. No stock-based employee compensation expense was recognized in the Company's Consolidated Statement of Operations prior to July 1, 2006, as all options granted under the Company's stock-based compensation plans had an exercise price equal to the market value of the underlying common stock on the date of grant. Effective July 1, 2006, the Company adopted the fair value recognition provisions of SFAS No. 123 (R), Share Based Payment, using the modified-prospective transition method as described in SFAS No. 148, Accounting for Stock-Based Compensation - Transition and Disclosure. Under this method, compensation cost recognized in the first quarter of fiscal 2007 is the same as that which would have been recognized had the recognition provisions of Statement 123 been applied from its original effective date.

A summary of the pro forma effects to reported net income and earning per share, as if the Company had elected to recognize compensation cost based on the fair value of the options granted at grant date as prescribed by SFAS No. 123 for all periods presented prior to the adoption of SFAS No. 123(R):

	Nine Months Ended March 31, 2006
Net income, as reported	$ 1,796,921
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	
Deduct: Total stock-based compensation expense determined under fair value based method for all awards, net of related tax effects	(244,595)
Pro forma net income	$ 1,552,326
Basic Earnings Per Share	
As Reported	0.27
Pro Forma	0.23
Diluted Earnings Per Share	
As Reported	0.24

Pro Forma	0.21

NOTE 3 - SHARE-BASED COMPENSATION (Continued)

On August 11, 2006, the Board Chairman ("Mr. Bailey") exercised his option for 50,000 shares of our common stock granted March 14, 2002 at a price of $0.57 per share. As consideration for the option shares purchased, Mr. Bailey paid cash consideration of $28,500.

On August 14, 2006, an employee exercised her option for 17,000 shares of our common stock granted March 14, 2002 at a price of $0.57 per share. As consideration for the option shares purchased, the employee surrendered 2,019 shares equal to the exercise price.

Additionally, 10,000 options were granted to a non-employee Director on September 11, 2006. The fair value of those options was estimated using the Black-Scholes option-pricing model with the following assumptions: no dividend yield, expected volatility of 73%, risk free interest rates of 4.97% and expected life of 5 years. As a result, $23,500 was recognized as Director Fees during the first quarter of fiscal year 2007.

A summary of option activity under the plans as of March 31, 2007, and changes during the nine months then ended, is presented below:

	Number of Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term
Outstanding at June 30, 2006	484,000	$ 1.56	
Granted	10,000	3.70	
Exercised	(64,981)	0.57	
Forfeited or expired	(99,019)	0.57	
Outstanding at March 31, 2007	330,000	$ 1.75	2.13
Exercisable at March 31, 2007	223,334	$ 1.69	1.37

The grant-date fair value of options granted during the period was $23,508. The total intrinsic value of options exercised during the period was $185,845.

A summary of the status of the Company's nonvested shares underlying the options outstanding as of March 31, 2007, and changes during the nine months ended March 31, 2007, is presented below:

	Number of Shares	Weighted-Average Grant-Date Fair Value
Nonvested at June 30, 2006	256,666	$ 1.85
Granted	--	
Vested	(106,667)	1.69
Forfeited	(43,333)	2.67
Nonvested at March 31, 2007	106,666	$ 1.68

The total compensation cost related to nonvested awards not yet recognized on March 31, 2007 is approximately $16,000 net of tax, and the weighted average period over which this cost is expected to be recognized is 1.3 years. The total fair value of options vested during the period was $180,267.

NOTE 3 - SHARE-BASED COMPENSATION (Continued)

The following information summarizes information with respect to options granted under equity plans:

		Outstanding		Exercisable	
Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life in Years (1)	Weighted Average Exercisable Price	Number Exercisable	W Ex
$ 0.57	150,000	1.38	$ 0.57	100,000	
2.67	170,000	2.76	2.67	113,334	
3.70	10,000	4.45	3.70	10,000	
	330,000	2.18	$ 1.75	223,334	

(1) The term of the option will be the earlier of the contractual life of the options or 90 days after the date the optionee is no longer an employee, consultant or director of the Company.

NOTE 4 - EARNINGS PER SHARE

The Company's calculation of earnings per share of common stock is as follows:

	Nine Months Ending March 31,				
	2007			2006	
	Net Income	Shares	Per Share Amount	Net Income	Shar
Basic Earnings Per Share:					
Net income and share amounts	$1,034,747	7,149,735	$0.14	$1,796,921	6,7
Effect of Dilutive Securities:					
Stock Options	-	176,950	-	-	5
Diluted Earnings Per Share:					
Net income and assumed share conversion	$1,034,747	7,326,685	$0.14	$1,796,921	7,3

NOTE 5 - INCOME TAXES

The Company uses the asset and liability method of accounting for deferred income taxes. Deferred tax assets and liabilities are determined based on the temporary differences between the financial statement and tax basis of assets and liabilities. Deferred tax assets or liabilities at the end of each period are determined using the tax rate in effect at that time.

The total future deferred income tax liability is extremely complicated for any energy company to estimate due in part to the long-lived nature of depleting oil and gas reserves and variables such as product prices. Accordingly, the liability is subject to continual recalculation, revision of the numerous estimates is required, and may change significantly in the event of such things as major acquisitions, divestitures, product price changes, changes in reserve estimates, changes in reserve lives, and changes in tax rates or tax laws.

NOTE 6 - CONTINGENCIES AND DRILLING COMMITMENTS

In January 2007 Aspen entered into a venture to explore for gold in Alaska with Hemis Corporation, with offices in Las Vegas, Nevada, whereby Hemis will provide all funding and be the operator of a venture to carry out permit acquisition and exploration for commercial quantities of gold. If such deposits are found, Hemis intends to produce and sell the gold as well as any other commercially valuable minerals that may occur with the gold. Hemis has commenced work to obtain permits for the project.

At signing Aspen was paid $50,000 and will be paid this amount on each anniversary of the agreement so long as Hemis continues work in the area. The payment ceases when and if production begins. Aspen retained a 5% production royalty, which may be taken in kind or in cash as Aspen prefers. Aspen provided to Hemis exploration data assembled and gathered by Aspen over a period of several years in the 1980's. Permits will be required before Hemis may commence work and there is no assurance such needed permits will be issued by the State of Alaska or by the Federal government.

The Company and Enserco Energy, Inc. entered into a "Contract for Sale and Purchase of Natural Gas" dated November 1, 2005. Aspen and Enserco have continuously renewed this contract since then. On January 30, 2007 Aspen agreed to sell and Enserco 2,000 MMBTU (million BTUs or British Thermal Units) of gas per day at a fixed price of $7.65 per MMBTU less transportation and other expenses during the period April 1, 2007 through October 31, 2007. On April 12, 2007, the Company entered into a subsequent renewal of the gas sales contract to sell Enserco 2,000 MMBTU of gas per day at a fixed price of $9.02 per MMBTU less transportation and other expenses during the period from November 1, 2007 through March 31, 2008.

Aspen's sales of natural gas under the Enserco Contract qualify for the "Normal Purchases and Normal Sales" exception in paragraph 10(b) of FAS 133. The Enserco Contract contains net settlement provisions should the Company fail to deliver natural gas when required under the Enserco Contract. Those provisions are mutual and establish the sole and exclusive remedy of the parties in the event of a breach of a firm obligation to deliver or receive natural gas. The provisions are summarized as follows:

(i) In the event of a breach by Aspen on any day, Aspen would be required to pay Enserco an amount equal to the positive difference, if any, between the purchase price and transportation costs paid by Enserco purchasing replacement natural gas and the amount of Aspen's default; or

(ii) In the event of a breach by Enserco on any day, Enserco must pay to Aspen any losses incurred by Aspen after attempting the resale of the natural gas; or

(iii) In the event that Enserco has used commercially reasonable efforts to replace the natural gas not delivered by Aspen, or Aspen has used commercially reasonable efforts to sell the undelivered natural gas to a third party and no such replacement or sale is available, the sole and exclusive remedy of the performing party shall be any unfavorable difference between the contract price and the spot price, adjusted for transportation.

The natures of the penalties are based on the current market prices and therefore are variable. Aspen has met its obligations under the contract since the inception of the contract, and expects to continue to have sufficient gas available for delivery to fulfill current contractual delivery quantity obligations from anticipated production from the Company's California fields.

The Company has the following commitments for drilling and completion for the period April 2007 through June 2007:

Area	Wells	Drilling Costs	Completion and Equipment Costs
Poplar Field Roosevelt County, MT	Various Recompletions	$-	$125,000
West Grimes Field Colusa County, CA	3	490,000	280,000
Kirk Field Colusa County, CA	1	306,000	183,000
Total Expenditures	4	$796,000	$588,000

NOTE 7 - DIVIDENDS

On November 8, 2006, the Company declared a cash dividend in the amount of $0.05 per share. The total of $357,981 was paid to the shareholders on December 6, 2006, as determined by shareholders of record as of November 20, 2006.

NOTE 8 - PROPERTY ACQUISITIONS

In February 2007, Aspen purchased a working interest in certain oil producing assets encompassing 22,600 acres in the East Poplar Unit and the Northwest Poplar Field in Roosevelt County, Montana located in the Williston Basin. Aspen acquired its interest from Nautilus Poplar, LLC, an unaffiliated entity, on the same day that Nautilus Poplar LLC acquired the assets from Ballard Petroleum Holdings, Inc., also an unaffiliated entity. The Unit and Field contain a total of 33 producing oil wells, and 7 salt-water disposal wells. Current production is 230 gross BOPD from the Charles "B" reservoir. The average net revenue interest that Nautilus Poplar LLC acquired (before its conveyance to Aspen) is greater than 80%, and Aspen's interest in revenues from the Poplar Field will remain at 12.5% of the total interest acquired by Nautilus (about a 10% net revenue interest based on an average 80% NRI) until Aspen receives a return of 110% of its investment. Thereafter, Aspen's interest will be reduced to 10% of that acquired by Nautilus (approximately an 8.0% net revenue interest to Aspen). The crude oil is 40 degrees API sweet and is readily marketed at the lease boundary. All produced water is disposed within the Unit boundary.

Aspen's participation in the acquisition will provide the Company with diversification into long-lived oil reserves. There is also upside reserve potential via increased water disposal capacity, re-activation of old wells, water shut off techniques, behind-pipe potential in the Charles A, B, & C, and drilling potential in the Mission Canyon and Nisku. This acquisition also provides ownership in 3-D seismic data over 22,600 acres. This acquisition is not expected to generate any significant cash flow for Aspen for the first two years.

Aspen will pay 12.5% of the costs for a 10% working interest in the project. During the first year, Aspen will also receive 12.5% of the net revenues (after deduction for royalties, taxes, operating expenses, etc.) until 110% payout, at which time Aspen's working interest reverts to 10%. After the first year, even if 110% payout has not occurred, Aspen will only pay 10% of the costs and receive 12.5% of the net revenues until 110% payout. After 110% payout, Aspen will have a 10% working interest and receive 10% of the net revenues. The initial cost to Aspen for its 12.5% before payout working interest (including its share of the acquisition costs) was approximately $1,450,000, which is approximately $1,075,000 after deduction of $375,000 (12.5% of the $3,000,000 loan proceeds obtained by Nautilus in connection with the purchase), with an additional $400,000 of anticipated capital expenditures during the first year. Aspen funded its participation in this project with a combination of bank debt ($600,000, discussed in Note 9, below), cash on hand and the sale of approximately 100,000 shares of UR Energy stock (which yielded about $330,000). Closing of this acquisition occurred on February 13, 2007.

NOTE 9 - LONG-TERM AND SHORT-TERM OBLIGATIONS

Long-term debt

In January 2007, we borrowed $600,000 from Wells Fargo Bank, NA pursuant to a promissory note payable over thirty-six months to partially finance the acquisition of the Poplar Field discussed in Note 8. Interest on the note is charged at LIBOR plus 2.25%. We subsequently entered into an interest rate swap

agreement with Wells Fargo Bank, which fixes the interest rate on the note at 8.10%. Principal of $16,667 plus interest payments are due monthly beginning February 15, 2007 and continuing to January 15, 2010. Collateral consists of a blanket filing on Accounts Receivables. At March 31, 2007 the outstanding balance on the note was $566,666, of which $200,004 is classified as current.

The Wells Fargo note contains restrictive covenants which, among other things, requires us to maintain a certain "Net Worth" defined as total stockholder's equity of not less that $9,000,000 at any time, net income after taxes not less than $1,000 on an annual basis and an EBITDA ratio, as defined.

Short-term debt

In February 2007, as part of the Poplar acquisition, Aspen agreed to be responsible for 12.5% of a $3,000,000 loan obtained by Nautilus in connection with the purchase of the Poplar Field assets. Nautilus Poplar, LLC obtained the loan from the Jonah Bank of Wyoming, as lender. Aspen's share of this loan is $375,000 plus interest at a rate of 9.0%, and Aspen is subject to the repayment schedule that Nautilus Poplar negotiated and to the other terms and conditions of the loan agreement as fully as if Aspen were a party to the loan agreement. Aspen's share of principal payments of $6,250 plus interest are due monthly through February 25, 2009. At March 31, 2007, the outstanding balance was $368,750, of which $75,000 is classified as current.

NOTE 10 - SUBSEQUENT EVENTS

On April 12, 2007, the Company entered into a renewal of its gas sales contract with Enserco Energy, Inc. as described above in Note 6.

On April 9, 2007 Aspen's President and CEO, Mr. Cohan, exercised options to purchase 100,000 shares at a price of $0.57 each, for total cash consideration of $57,000.

Item 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

General

The following discussion provides information on the results of operations for the periods ended March 31, 2007 and 2006 and our financial condition, liquidity and capital resources as of March 31, 2007 and June 30, 2006. The financial statements and the notes thereto contain detailed information that should be referred to in conjunction with this discussion.

The profitability of our operations in any particular accounting period will be directly related to the realized prices of oil and gas sold, the type and volume of oil and gas produced and the results of development, exploitation, acquisition, and exploration activities, and the other factors set forth in this report and in our report on Form 10-KSB for the year ended June 30, 2006. The realized prices for natural gas will fluctuate from one period to another due to regional market conditions and other factors, while oil prices will be predominantly influenced by world supply and demand. The aggregate amount of oil and gas produced may fluctuate based on the success of development and exploitation of oil and gas reserves pursuant to current reservoir management. Accordingly, our results of operations may fluctuate from period to period based on the foregoing principal factors, among others.

Overview

Aspen Exploration Corporation was organized in 1980 for the purpose of acquiring, exploring and developing oil and gas and other mineral properties. Since 1996, we have focused our efforts on the exploration, development and operation of natural gas properties in the Sacramento Valley of northern California. We are currently the operator of 56 gas wells in California, own non-operating interests in an additional 20 gas wells in California and approximately 33 oil wells in Montana.

We currently have offices in Bakersfield, California and Denver, Colorado and have 2 full time employees as well as the Chairman of the Board who allocates a portion of his time to the Company. We also make extensive use of consultants for the conduct of our business, ranging from financial, engineering, land, legal, and geological and geophysical specialists.

Where possible, we attempt to be the operator of each property in which we invest in California. Our knowledge of drilling and operating wells in the Sacramento Valley allows us to maximize the potential return of each property. Administrative charges to the properties help cover approximately 58% and 37% of our selling, general and administrative expenses for the three and nine-month periods ended March 31, 2007, respectively.

Outlook and Trends

Total production for the year depends on a variety of factors set forth herein and in our Form 10-KSB for the year ended June 30, 2006. Over the past five years, through our exploration and development activities and property acquisitions, the Company has been able to increase our oil and gas reserves notwithstanding our production. Since our 2003 fiscal year, only at June 30, 2005, were our reserves at year-end less than our reserves at the previous year-end.

We have entered into contracts with Enserco Energy, Inc. to sell about 30% of our production from April 1, 2007 through March 31, 2008. We also anticipate that the average price for our product will be in the range of $4.00 to $9.00 per million British Thermal Unit (MMBTU) for the fiscal year ended June 30, 2007 as compared to the average gas price of $8.03 received during our 2006 fiscal year. We received an average of $7.75 per MMBTU for the three months ended March 31, 2007 as compared to an average of $8.18 per MMBTU during the third quarter of our 2006 fiscal year.

Quantitative and Qualitative Disclosure About Risk

The prices that we receive for the oil and natural gas (including natural gas liquids) produced are impacted by many factors that are outside of our control. Historically, these commodity prices have been volatile and we expect them to remain volatile. Prices for oil and natural gas are affected by changes in market demands, overall economic activity, weather, pipeline capacity

constraints, inventory storage levels, the world political situation, basis differentials and other factors. As a result, we cannot accurately predict future natural gas and NGL (natural gas liquids) prices, and therefore, we cannot determine what effect increases or decreases in production volumes will have on future revenues.

On regulatory and operational matters, we actively manage our exploration and production activities. We value sound stewardship and strong relationships with all stakeholders in conducting our business. We attempt to stay abreast of emerging issues to effectively anticipate and manage potential impacts to our operations.

To manage commercial risk, we may use financial tools to hedge the price we will receive for our product. The primary purpose of hedging is to provide adequate return on our investments, grow our reserves while leaving as much commodity price upside as possible. We have done so through a contract with Enserco Energy, Inc., since November 1, 2005. Under the current renewal of that contract, we are contractually obligated to deliver 2,000 MMBTU per day at $7.65 per MMBTU through October 31, 2007, and then $9.02 per MMBTU through March 31, 2008. These contracts were designated as normal sales contracts.

Liquidity and Capital Resources

We have historically financed our operations with internally generated funds and limited borrowings from banks and third parties, and farmout arrangements, which permit third parties (including some related parties) to participate in our drilling prospects, although during the quarter ended March 31, 2007, we also borrowed $600,000 to purchase an interest in the Poplar Field and became obligated for an additional $375,000 indebtedness.

Our principal uses of cash are for operating expenses, the acquisition, drilling, completion and production of prospects, the acquisition of producing properties, working capital, servicing debt and the payment of income taxes. During the first nine months of our 2007 fiscal year, we used more than $3.2 million of cash in our operations, investing activities and financing activities as compared to those activities generating more than $3.6 million during the same period of our 2006 fiscal year.

We generated cash of $353,149 from operations for the nine months ended March 31, 2007, as compared to $6,890,825 cash generated from operating activities for the nine months ended March 31, 2006. This negative change of approximately $6.5 million was due to a number of factors, including a reduction of our net income of approximately $762,000 (as discussed below in results of operations), and a use of cash to retire current liabilities (which were more than $6 million at June 30, 2006 as compared to less than $4 million at March 31, 2007). Our current liabilities decreased by about $2.2 million during the 2007 period as compared to an increase in current liabilities of approximately $6.9 million during the 2006 period.

Investing activities used cash to increase capitalized oil and gas costs and office equipment of $3.9 million during the first nine months of 2007 as compared to $3.2 million in the nine months ended March 31, 2006. Cash in the current nine month period ended March 31, 2007 was used for oil and gas property acquisition ($1.01 million), lease acquisition, seismic work, intangible drilling and well workovers and equipment ($2.7 million), and support equipment of ($89,000). These expenditures are net of the sale of interests in wells to be drilled charged to third party investors.

We have a proposed drilling budget for the period April 2007 through June 2007. The budget includes drilling four wells in California and re-completing / repairing several wells in Montana. Our share of the estimated costs to complete this program is set forth in the following table:

Area	Wells	Drilling Costs	Completion and Equipment Costs
Poplar Field Roosevelt County, MT	Various Recompletions	$ -	$125,000
West Grimes Field Colusa County, CA	3	490,000	280,000
Kirk Field Colusa County, CA	1	306,000	183,000
Total Expenditures	4	$796,000	$588,000

Our working capital (current assets less current liabilities) at March 31, 2007, was $2.97 million, which reflects an approximate $902,000 decrease from our working capital of approximately $3.9 million at June 30, 2006. Our working capital decreased during the first nine months of our 2007 fiscal year because of our negative cash flow of more than $3.9 million from investing activities and a significant use of cash to reduce our current liabilities.

We anticipate that our working capital and anticipated cash flow from operations and future successful drilling activities will be sufficient to finance our drilling and operating expenses for the next twelve months and to pay our other obligations. Based on national and international concerns, we anticipate that our gas production will continue to provide us with sufficient cash flow through our current fiscal year and beyond. As discussed herein, this is dependent, in part, on maintaining or increasing our level of production and the national and world market maintaining its current prices for our gas production.

If our drilling efforts are successful, the anticipated increased cash flow from the new gas discoveries, in addition to our existing cash flow, should be sufficient to fund our share of planned future completion and pipeline costs.

Results of Operations

March 31, 2007 Compared to March 31, 2006

In general, our operations during 2007 have been adversely affected by reduced production and average prices received for our production, together with increasing costs of production and accretion, depletion, depreciation, and amortization, and increased general and administrative expenses. Aspen is aware of these changes, but believes that some of the negative trend in cash flow is temporary as a result of the addition of our Poplar Field properties acquired in the current quarter. As noted, oil and gas prices are subject to national and international pressures, and Aspen has no control over those prices.

For the nine months and three months ended March 31, 2007, our operations continued to be focused on the production of oil and gas, and the acquisition of producing oil and gas properties in California and Montana. Our oil and gas production decreased from 531,000 MMBTU sold during the first nine months of March 31, 2006, to 488,000 MMBTU sold during the same period in 2007 (a decrease of approximately 8%). As a result of our decreased production and decreased prices during the first nine months of our 2007 fiscal year ($6.89 per MMBTU during 2007 as compared to $8.62 per MMBTU during the same period in 2006), our revenues from oil and gas sales decreased during the 2007 period by approximately $1.2 million from approximately $4.6 million (2006) to approximately $3.4 million (2007), and decreased during the three month periods from $1,496,427 (2006) to $1,344,791 (2007). A comparison of the three month period ending March 31, 2007 to the same period in 2006 similarly results in a decrease in production of (5%), a decrease in price per MMBTU of (5%), and a decrease in revenue of (10%).

Oil and gas production costs increased approximately 62% and 50% in the nine and three months ended March 31, 2007, respectively, as compared to the same periods in 2006, from approximately $357,000 to more than $577,000, and during the three month periods from $164,796 (2006) to $247,292 (2007). The increase can be attributed to the addition of 5 gross operated gas wells, from 51 wells to 56 wells and our percentage working interests in these wells were somewhat higher than the average of wells owned at March 31, 2006. The increase was also due to the addition of 33 producing oil wells and 7 saltwater disposal wells in Montana as well as the payment of a full year of ad valorem taxes in several of the California counties where Aspen's gas wells are located. Equipment rental and water disposal fees increased due to the addition of compressors and increased water production in our more mature wells. Additionally, all of the costs for the service companies who perform work on Aspen's wells increased dramatically during the past twelve months.

Depletion, depreciation and amortization expense increased 32%, from approximately $1,159,000 for the nine months ended March 31, 2006 as compared to more than $1,528,000 during the 2007 period, and during the three month periods from $450,000 (2006) to $548,176 (2007). This increase was the result of using the approximate same depletion rate as fiscal 2006, but applying it to a larger full cost pool, which resulted in the higher total depletion taken.

16

Our general and administrative expenses increased 57%, from approximately $669,000 during the nine months ended March 31, 2006 to approximately $1,047,000 during the 2007 period because of increased audit and accounting fees, officers salaries including a non-cash charge of $85,500 as a result of recognition of additional share-based compensation expense in accordance with the implementation of FAS 123(R), a non-cash charge of $23,500 for stock options issued to a Director, and the amortization of deferred compensation for the initiation of an investor relations service of $119,233 settled in shares of our common stock in the prior year. Our general and administrative expenses increased 30%, from approximately $205,592 during the three months ended March 31, 2006 to approximately $266,728 during the 2007 period for the same reasons.

The following table sets forth certain items from our Condensed Consolidated Statements of Operations as expressed as a percentage of total revenues, shown for the nine months of fiscal 2007, 2006, and 2005:

	For the Nine Months Ended	
	March 31, 2007	March 31, 2006
Total Revenues	100.0%	100.0%
Oil and Gas Production Costs	15.4%	7.3%
Gross Operating Profit	84.6%	92.7%
Expenses		
Depreciation and depletion	40.8%	23.8%
Selling, general and administrative	27.9%	13.7%
Total operating expenses	84.1%	44.8%
Income from operations	15.9%	55.2%
Other Income (expenses)	19.4%	0.9%
Provision for Income Taxes	7.7%	19.2%

Net Income (Loss)	27.6%	36.9%	

To facilitate discussion of our operating results for the nine months ended March 31, 2007 and 2006, we have included the following selected data from our Condensed Consolidated Statements of Operations:

	Comparison of the Fiscal Nine Months Ended March 31,		Increase
	2007	2006	Amount
Revenues:			
Oil and gas sales	$ 3,361,563	$ 4,576,203	$(1,214,640)
Management fees	386,818	295,768	91,050
Total Revenues	3,748,381	4,871,971	(1,123,590)
Cost and Expenses:			
Oil and gas production	576,534	356,966	219,568
Depreciation and depletion	1,528,330	1,159,040	369,290
General and administrative	1,047,065	668,654	378,411
Total Costs and Expenses	3,151,929	2,184,660	967,269
Operating Income	596,452	2,687,311	(2,090,859)
Other income (expenses)	725,688	43,619	682,069
Income Tax Benefit (Provision)	(287,393)	(934,009)	646,616
Net Income (Loss)	$ 1,034,747	$ 1,796,921	$ (762,175)

Total revenue decreased $1.1 million or 23% when comparing the two periods, while operating and production costs increased $967,000, or 44%.

A significant ratio presented is the percentage of management fees charged to operated wells versus our general and administrative costs. This ratio coverage of general and administrative costs decreased from approximately 44% during the nine months ended March 31, 2006 to approximately 37% at March 31, 2007.

Central to the issue of success of the nine months operations ended March 31, 2007 is the discussion of changes in oil and gas sales, volumes of natural gas sold and the price received for those sales. We present them here in tabular form:

	Oil & Gas Sales	MMBTU Sold	(1) Price/MMB
2007			
1st Quarter	$962,933	158,391	
2nd Quarter	1,053,839	156,002	
3rd Quarter	1,344,791	173,623	
Year to date	3,361,563	488,016	
2006			
1st Quarter	1,062,543	146,445	
2nd Quarter	2,018,233	201,371	
3rd Quarter	1,496,427	182,987	
4th Quarter	823,747	141,840	
Year to date	5,400,950	672,643	
2005			
1st Quarter	697,553	130,000	
2nd Quarter	1,132,359	177,350	
3rd Quarter	1,103,687	169,150	
4th Quarter	919,578	145,500	
Year to date	3,853,177	622,000	
2004			
1st Quarter	341,926	72,600	
2nd Quarter	362,942	79,900	
3rd Quarter	401,941	71,900	
4th Quarter	481,441	80,600	
Year to date	1,588,250	305,000	
Third Quarter Change			
2007			
Amount	$ (151,636)	$ (9,364)	$ (
Percentage	-10%	-5%	
2006			
Amount	$392,740	$13,837	
Percentage	35%	8%	

(1) Price per MMBTU may not agree with oil and gas sales because of the inclusion of oil and NGL sales.

Oil and gas revenue and volumes sold of our product have shown a general decrease over the first nine months of fiscal 2007. As the table above notes, revenue has decreased approximately 27% when comparing the nine-month periods ended March 31, 2007 and 2006. Volumes sold decreased approximately 8%, while the price received for our product decreased 19%.

Contractual Obligations

We maintain office space in Denver, Colorado, our principal office, and Bakersfield, California. The Denver office consists of approximately 1,108 square feet with an additional 750 square feet of basement storage. We entered into a one-year lease agreement on the Denver office through December 31, 2004 at a lease rate of $1,261 per month. We are currently leasing this space on a month to month basis. The Bakersfield, California office has 546 square feet and lease payments are $901 to $934 over the term of the lease, which expires July 31, 2008. Rent expense for the nine months ended March 31, 2007 and 2006 was $19,778 and $24,372, respectively.

Effective November 1, 2006 through March 31, 2007, we were contractually obligated to deliver 2,000 MMBTU per day at $10.15 per MMBTU, effective December 1, 2006 through March 31, 2007, we were contractually obligated to deliver an additional 2,000 MMBTU per day at $7.30 per MMBTU, effective April 1, 2007 through October 31, 2007, we are contractually obligated to deliver 2,000 MMBTU per day at $7.65 per MMBTU, and effective November 1, 2007 through March 31, 2008, we are contractually obligated to deliver 2,000 MMBTU per day at $9.02 per MMBTU to one of our natural gas purchasers. These contracts were designated as normal sales contracts.

Critical Accounting Policies and Estimates

The Company believes the following accounting policies and estimates are critical in the preparation of its consolidated financial statements: the carrying value of its oil and natural gas properties, the accounting for oil and gas reserves, and the estimate of its asset retirement obligations.

Oil and Gas Properties

The Company uses the full cost method of accounting for costs related to its oil and natural gas properties. Capitalized costs included in the full cost pool are depleted on an aggregate basis using the units-of-production method. Depreciation, depletion and amortization is a significant component of oil and natural gas properties, but does not impact cash flow. A change in proved reserves without a corresponding change in capitalized costs will cause the depletion rate to increase or decrease.

Both the volume of proved reserves and any estimated future expenditures used for the depletion calculation are based on estimates such as those described under "Reserve Estimates" below.

The capitalized costs in the full cost pool are subject to a quarterly ceiling test that limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved oil and natural gas reserves discounted at 10 percent plus the lower of cost or market value of unproved properties less any associated tax effects. If such capitalized costs exceed the ceiling, the Company will record a write-down to the extent of such excess as a non-cash charge to earnings. Any such write-down will reduce earnings in the period of occurrence and result in lower depreciation and depletion in future periods. A write-down may not be reversed in future periods, even though higher oil and natural gas prices may subsequently increase the ceiling. Aspen has not recognized any write-downs of the full cost pool during the first nine months of 2007 or the comparable period in 2006.

Changes in oil and natural gas prices have historically had the most significant impact on the Company's ceiling test. In general, the ceiling is lower when prices are lower. Even though oil and natural gas prices can be highly volatile over weeks and even days, the ceiling calculation dictates that prices in effect as of the last day of the test period be used and held constant. The resulting valuation is a snapshot as of that day and, thus, is generally not indicative of a true fair value that would be placed on the Company's reserves by the Company or by an independent third party. Therefore, the future net revenues associated with the estimated proved reserves are not based on the Company's assessment of future prices or costs, but rather are based on prices and costs in effect as of the end of the test period.

Other Developments

Subsequent to the quarter ending March 31, 2007, the Emigh #34-1 well, located in the Denverton Creek Field, Solano County, California, was deepened from a depth of 10,200 feet to 10,761 feet, and encountered potential gas pay in the Third Starkey and Petersen formations. A production liner was run based on favorable mud log and electric log responses. Aspen has a 45% operated working interest in this well. The well is currently waiting on a completion rig.

In addition, the WGU #14-10 well, located in the West Grimes Gas Field, Colusa County, California, was directionally drilled to a depth of 8,460 feet (7,974 feet TVD) and encountered encouraging mud log shows and electric log responses in several intervals in the Forbes formation. Production casing was run and the well is currently waiting on a completion rig. Aspen has a 21% operated working interest in this well.

Reserve Estimates

Our estimates of oil and natural gas reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future oil and natural gas prices, future operating costs, severance and excise taxes, development costs and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected therefrom may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of our oil and gas properties and/or the rate of depletion of the oil and gas properties. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

Many factors will affect actual future net cash flows, including:

- The amount and timing of actual production;
- Supply and demand for natural gas;
- Curtailments or increases in consumption by natural gas purchasers; and
- Changes in governmental regulations or taxation.

Accounts Receivable

Accounts receivable balances are evaluated on a continual basis and allowances are provided for potentially uncollectible accounts based on management's estimate of the collectibility of customer accounts. If the financial condition of a customer were to deteriorate, resulting in an impairment of its ability to make payments, an allowance may be required. Allowance adjustments are charged to operations in the period in which the facts that give rise to the adjustments become known; however, no allowance is recorded for the period ending March 31, 2007, as all receivables are expected to be collected in full.

Asset Retirement Obligations

We recognize the future cost to plug and abandon gas wells over the estimated useful life of the wells in accordance with the provision of SFAS No. 143. SFAS No. 143 requires that we record a liability for the present value of the asset retirement obligation with a corresponding increase to the carrying value of the related long-lived asset. We amortize the amount added to the oil and gas properties and recognize accretion expense in connection with the discounted liability over the remaining lives of the respective gas wells. Our liability estimate is based on our historical experience in plugging and abandoning gas wells, estimated well lives based on engineering studies, external estimates as to the cost to plug and abandon wells in the future and federal and state regulatory requirements. The liability is discounted using a credit-adjusted risk-free rate of 5%. Revisions to the liability could occur due to changes in well lives, or if federal and state regulators enact new requirements on the plugging and abandonment of gas wells.

Deferred Taxes

Deferred income taxes have been determined in accordance with Statement of

Financial Accounting Standards No. 109, "Accounting for Income Taxes." For the period ended March 31, 2007 the Company recorded income tax expense of $287,000. Projections of future income taxes and their timing require significant estimates with respect to future operating results. Accordingly, the net deferred tax liability is continually re-evaluated and numerous estimates are revised over time. As such, the net deferred tax liability may change significantly as more information and data is gathered with respect to such events as changes in commodity prices, their effect on the estimate of oil and gas reserves, and the depletion of these long-lived reserves.

Off Balance Sheet Arrangements

We have no off balance sheet arrangements and thus no disclosure is required.

Forward Looking Statements

"Safe harbor under the Private Securities Litigation Reform Act of 1995:" Any statements in this Form 10-QSB that are not historical facts are forward-looking statements that involve risks and uncertainties. Words such as "estimate," "will," "intend," "continue," "target," "expect," "achieve," "strategy," "future," "may," "goal(s)," or other comparable words or phrases or the negative of those words, and other words of similar meaning indicate forward-looking statements and important factors which could affect actual results. Forward-looking statements are made based on Management's current expectations and beliefs concerning future developments and their potential effects upon Aspen Exploration Corporation. These items are discussed at length in Part I, on page 25 of Aspen's Form 10-KSB filed with the Securities and Exchange Commission, under the heading "Factors That May Affect Future Operating Results" in the section titled "Management's Discussion and Analysis of Financial Condition or Plan of Operation." No material changes are have been noted as of the filing of this 10-QSB.

Item 3. CONTROLS AND PROCEDURES

As of March 31, 2007, we have carried out an evaluation under the supervision of, and with the participation of the Chief Executive Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities and Exchange Act of 1934, as amended.

Based on the evaluation as of March 31, 2007, the Chief Executive Officer (who is also our principal financial officer) has concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e)) under the Securities Exchange Act of 1934) are effective to ensure that the information required to be disclosed in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

There was no change in our internal control over financial reporting during the most recently completed fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II

Item 1. LEGAL PROCEEDINGS

There are no material pending legal or regulatory proceedings against Aspen Exploration Corporation, and it is not aware of any that are known to be contemplated.

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following sets forth the information required by Item 701 of Regulation S-B with respect to the unregistered sale of equity securities:

On August 11, 2006, our Board chairman, R. V. Bailey, exercised options for 50,000 shares of our common stock granted March 14, 2002, at an average price of $0.57 per share. Mr. Bailey paid us $28,500 to exercise his options on the 50,000 shares.

(a) The options were exercised on August 11, 2006, to purchase 50,000 shares of our common stock.

(b) No underwriter, placement agent, or finder was involved in the transaction. The Board chairman is an accredited investor.

(c) The total exercise price for the options was $28,500, which was paid in cash. No underwriting discounts or commission were paid.

(d) We relied on the exemption from registration provided by Section 4(2) and 4(6) under the Securities Act of 1933 for this transaction and Regulation D for the issuance. We did not engage in any public advertising or general solicitation in connection with this transaction, and we provided the accredited investor with disclosure of all aspects of our business, including providing the accredited investor with our reports filed with the Securities and Exchange Commission, our press releases, access to our auditors, and other financial, business, and corporate information. Based on our investigation, we believe that the accredited investor obtained all information regarding Aspen Exploration it requested, received answers to all questions it (and its advisors) posed, and otherwise understood the risks of accepting our securities for investment purposes.

(e) The common stock issued in this transaction is not convertible or exchangeable.

(f) We will use the proceeds for working capital, as well as expenses of drilling and (if warranted) completing oil and gas wells.

On August 14, 2006, an employee surrendered 2,019 mature shares of common stock to exercise a stock option resulting in the net issue of 14,981 shares. The option to acquire 17,000 shares was originally granted March 14, 2002, at an exercise price of $0.57 per share.

(a) The options were exercised on August 14, 2006, to purchase 17,000 shares of our common stock. The option holder exercised options to acquire 17,000 shares in the cashless exercise which had a value of $9,690 by surrendering 2,019 shares of Aspen's common stock with a fair value based on a ten-day average bid price immediately prior to the exercise date of $4.80.

(b) No underwriter, placement agent, or finder was involved in the transaction. The employee is an accredited investor.

(c) The total exercise price for the options was $9,690, which was paid by surrendering 2,019 shares to purchase 17,000 shares. No underwriting discounts or commission were paid.

23

(d) We relied on the exemption from registration provided by Section 4(2) under the Securities Act of 1933 for this transaction and Regulation D for the issuance. We did not engage in any public advertising or general solicitation in connection with this transaction, and we provided the accredited investor with disclosure of all aspects of our business, including providing the accredited investor with our reports filed with the Securities and Exchange Commission, our press releases, access to our auditors, and other financial, business, and corporate information. Based on our investigation, we believe that the accredited investor obtained all information regarding Aspen Exploration it requested, received answers to all questions it (and its advisors) posed, and otherwise understood the risks of accepting our securities for investment purposes.

(e) The common stock issued in this transaction is not convertible or exchangeable.

(f) We received no proceeds from the exercise of this transaction.

On April 9, 2007, President and CEO, Robert Cohan, exercised options for 100,000 shares of our common stock granted March 14, 2002, at an average price of $0.57 per share. Mr. Cohan paid $57,000 to exercise his options on the 100,000 shares.

(a) The options were exercised on April 9, 2007, to purchase 100,000 shares of our common stock.

(b) No underwriter, placement agent, or finder was involved in the transaction. Mr. Cohan is an accredited investor.

(c) The total exercise price for the options was $57,000, which was paid in cash. No underwriting discounts or commission were paid.

(d) We relied on the exemption from registration provided by Section 4(2) and 4(6) under the Securities Act of 1933 for this transaction and Regulation D for the issuance. We did not engage in any public advertising or general solicitation in connection with this transaction, and we provided the accredited investor with disclosure of all aspects of our business, including providing the accredited investor with our reports filed with the Securities and Exchange Commission, our press releases, access to our auditors, and other financial, business, and corporate information. Based on our investigation, we believe that the accredited investor obtained all information regarding Aspen Exploration it requested, received answers to all questions it (and its advisors) posed, and otherwise understood the risks of accepting our securities for investment purposes.

(e) The common stock issued in this transaction is not convertible or exchangeable.

(f) We will use the proceeds for working capital, as well as expenses of drilling and (if warranted) completing oil and gas wells.

Option to Director

Aspen appointed Kevan B. Hensman a director of Aspen effective September 11, 2006. In connection with that appointment, Aspen granted Mr. Hensman an option to purchase 10,000 shares of Aspen common stock.

(a) On September 11, 2006, we issued an option to purchase 10,000 shares of Aspen's common stock to Kevan B. Hensman. The options are exercisable at $3.70, expire September 11, 2011 and vested immediately.

(b) No underwriters were involved in this transaction.

(c) The stock options were issued in consideration of Mr. Hensman joining the board of directors and Aspen received no cash therefore.

(d) The transaction was exempt from registration under the Securities Act of 1933, as amended by reason of Section 4(2) and 4(6) of the Securities Act of 1933.

(e) The options are exercisable to purchase shares of common stock as described above.

(f) No proceeds were received.

Item 3. DEFAULTS UPON SENIOR SECURITIES

None.

Item 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matter was submitted during the first quarter of the fiscal year covered by this report to a vote of security holders, through the solicitation of proxies or otherwise.

Item 5. OTHER INFORMATION

None.

Item 6. EXHIBITS

Exhibit No.	Document
31	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (Robert A. Cohan, Chief Executive Officer).

32 Certification Pursuant to 18 U.S.C. ss.1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Robert A. Cohan, Chief Executive Officer).

Other exhibits and schedules are omitted because they are not applicable, not required or the information is included in the financial statements or notes thereto.

In accordance with the requirements of the Securities Exchange Act of 1934, we have duly caused this report to be signed on our behalf by the undersigned, thereunto duly authorized.

ASPEN EXPLORATION CORPORATION

Date: May 14, 2007

/s/ Robert A. Cohan

Robert A. Cohan, Chief Executive Officer and Chief Financial Officer
(principal executive and financial officer)