ASPEN EXPLORATION CORP
Form 10QSB
May 15, 2008

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, 2008

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 13, 2008**

Common stock, $.005 par value	7,259,622

Transitional small business disclosure format: Yes [ ] No [**X**]

Part One. FINANCIAL INFORMATION

Item 1. FINANCIAL STATEMENTS

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY

CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	March 31, 2008	June 30, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5,768,592	$ 4,057,279
Marketable securities, available for sale	807,915	1,120,485
Accounts and trade receivables	1,797,935	2,136,609
Other current assets	191,039	33,609
Total current assets	8,565,481	7,347,982
Property and equipment		
Oil and gas property (full cost method)	22,553,947	19,802,843
Support equipment	183,374	184,514
	22,737,321	19,987,357
Accumulated depletion and impairment - full cost pool	(9,950,552)	(8,083,383)
Accumulated depreciation - support equipment	(65,251)	(49,304)
Net property and equipment	12,721,518	11,854,670
Other assets:		
Deposits	263,650	263,650
Deferred income taxes	1,674,000	1,673,000
Total other assets	1,937,650	1,936,650
Total assets	$ 23,224,649	$ 21,139,302

(Statement Continues)

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

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY

CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED) (Continued)

	March 31, 2008	June 30, 2007
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 6,015,700	$ 2,961,100
Other current liabilities and accrued expenses	556,475	1,690,709
Notes payable - current portion	493,750	275,000
Asset retirement obligation, current portion	43,000	39,400
Deferred income taxes, current	75,000	342,000
Total current liabilities	7,183,925	5,308,209
Long-term liabilities		
Notes payable, net of current portion	166,667	591,667
Asset retirement obligation, net of current portion	566,514	447,253
Deferred income taxes	4,091,500	3,786,000
Total long-term liabilities	4,824,681	4,824,920
Stockholders' equity:		
Common stock, $.005 par value:		
Authorized: 50,000,000 shares		
Issued and outstanding: At March 31, 2008,		
and June 30, 2007, 7,259,622 shares	36,298	36,298
Capital in excess of par value	7,549,087	7,501,789
Accumulated other comprehensive loss	(354,095)	-
Retained earnings	3,984,753	3,468,086
Total stockholders' equity	11,216,043	11,006,173
Total liabilities and stockholders' equity	$ 23,224,649	$ 21,139,302

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

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

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007	Nine Months Ended March 31, 2008	Nine Months Ended March 31, 2007
Revenues:				
Oil and gas sales	$ 1,325,261	$ 1,344,791	$ 3,910,858	$ 3,361,563
Operating expenses:				
Oil and gas production	371,501	247,292	1,047,302	576,534
Accretion, and depreciation, depletion and amortization	546,912	548,176	1,910,003	1,528,330
Selling, general and administrative	135,322	111,852	363,333	660,247
Total operating expenses	1,053,735	907,320	3,320,638	2,765,111
Income from operations	271,526	437,471	590,220	596,452
Other income (expenses)				
Interest and other income	9,474	8,422	105,892	44,308
Interest and other expenses	(13,981)	(10,948)	(50,840)	(15,716)
Gain (loss) on investments	4,834	194,400	4,834	685,096
Gain on sale of equipment	-	-	-	12,000
Total other income (expenses)	327	191,874	59,886	725,688
Income before income taxes	271,853	629,345	650,106	1,322,140
Provision for income taxes	(67,014)	(212,393)	(133,439)	(287,393)
Net income	$ 204,839	$ 416,952	$ 516,667	$ 1,034,747
Basic net income per share	$ 0.03	$ 0.06	$ 0.07	$ 0.14
Diluted net income per share	$ 0.03	$ 0.06	$ 0.07	$ 0.14
Weighted average number of common shares outstanding used to calculate basic net income per share :	7,259,622	7,149,735	7,259,622	7,149,735
Effect of dilutive securities:				
Equity based compensation	39,912	176,949	39,912	176,950
Weighted average number of common shares outstanding used to calculate diluted net income per share :	7,299,534	7,326,684	7,299,534	7,326,685

Unaudited Condensed Statements of Comprehensive Income
Three and Nine Month Periods Ended March 31, 2008 and 2007

	Three Months Ended March 31,	Nine Months Ended March 31,

	2008	2007	2008	2007
Net income	$ 204,839	$ 416,952	$ 516,667	$ 1,034,747
Unrealized losses on available -for-sale securities,				
net of income tax of ($177,504), and ($243,494), respectively	(258,131)	-	(354,095)	-
Comprehensive income (loss)	$ (53,292)	$ 416,952	$ 162,572	$ 1,034,747

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

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

	Nine Months Ended March 31, 2008	Nine Months Ended March 31, 2007
Cash Flows from Operating Activities:		
Net income	$ 516,667	$ 1,034,747
Adjustments to reconcile net income to net cash provided by operating activities:		
Accretion and depreciation, depletion, and amortization	1,910,003	1,528,330
Deferred income taxes	280,994	212,500
Amortization of deferred compensation	-	119,233
Compensation expense related to stock options granted	47,298	109,008
Realized (gain) on marketable securities	(4,834)	(373,869)
Unrealized (gain) on marketable securities	-	(311,227)
Proceeds from sale of marketable securities	-	612,686
(Gain) on sale of vehicle	-	(12,000)
Changes in assets and liabilities:		
(Increase) decrease in current assets other than cash, cash equivalents, and short -term marketable securities	181,244	(155,884)
Increase (decrease) in current liabilities other than notes payable and asset retirement obligation	1,920,366	(2,410,375)
Net Cash Provided (Used) by Operating Activities	4,851,738	353,149
Cash Flows from Investing Activities:		
Additions to oil and gas properties	(2,653,991)	(2,718,200)
(Purchases) Sales of securities	(280,184)	(1,075,000)
Producing oil and gas properties purchased	-	(89,425)
Sale of property and equipment	-	12,000
Net Cash (Used) in Investing Activities	(2,934,175)	(3,870,625)
Cash Flows from Financing Activities:		
Proceeds from exercise of stock options	-	28,500
Proceeds from issuance of long-term debt	-	600,000
Payment of long-term debt	(206,250)	(39,584)
Payment of cash dividends	-	(357,981)
Net Cash Provided by (Used in) by Financing Activities	(206,250)	230,935
Net Increase (Decrease) in Cash and Cash Equivalents	1,711,313	(3,286,541)
Cash and Cash Equivalents, beginning of year	4,057,279	6,466,010
Cash and Cash Equivalents, end of year	$ 5,768,592	$ 3,179,469

Supplemental disclosures of cash flow information:				
Interest paid	$	50,840	$	15,716
Income taxes paid	$	-	$	800
Supplemental non-cash activity				
Decrease in fair value of marketable securities (net of income taxes of $243,494)	$	354,095	$	-
Increase in asset retirement obligation	$	95,973	$	149,949
Notes payable assumed	$	-	$	375,000

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

ASPEN EXPLORATION CORPORATION

Notes to Condensed Consolidated Financial Statements
(Unaudited)
March 31, 2008

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 Exc hange 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, 2007 and in the Form 10-KSB itself.

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

Accounting principles generally accepted in the United States of America require certain estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent liabilities at the date of the financial statements and reported amounts of revenues and expenses to be made. Actual results could differ from those estimates. The Company s significant estimates include estimated life of long-lived assets, use of reserves in the estimation of depletion of oil and gas properties, impairment of oil and gas properties, asset retirement obligation liabilities, and income taxes.

Investments in Debt and Equity Securities

Prior to the beginning of the current fiscal year, the Company classified all investments as Trading Securities in accordance with SFAS No. 115, *Accounting for Certain Investments in Debt and Equity Securities*. These securities were marked to market each period with the realized and unrealized gain or loss recorded in the statement of operations. The unrealized holding gain or loss at the date of the transfer (July 1, 2007), to the classification as available for sale, as described below, has already been recognized in earnings and shall not be reversed.

During the first quarter, management reassessed the appropriateness of the classification of the securities held, and determined that due to the sufficiency of the Company s cash flows to finance current operations and budgeted expenditures, the Company will hold investments until such time it determines there may be a need to sell those securities, or the company determines a sale to be in its best interest. Consequently, as of July 1, 2007, Management determined the securities are more appropriately classified as available for sale, and changes in the fair value of the securities are reported as a separate component of shareholders' equity until realized. Gains and losses are no longer a component of the Company's Statement of Operations.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES (Continued)

At March 31, 2008, the fair value of securities available for sale was $807,915. The gross unrealized holding gain (loss) during the three and nine months ended March 31, 2008, on securities still held as of March 31, 2008, was ($435,635) and ($597,589) respectively.

Recent Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board (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 has evaluated the effects of adopting this interpretation and determined there are no material uncertain tax positions.

In September 2006, Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements* was issued by the 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 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 for fiscal years beginning January 1, 2008 and the Company is evaluating the effects this pronouncement will have on the Company s financial statements.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations, which expands the information that a reporting entity provides in its financial reports about a business combination and its effects. This Statement establishes principles and requirements for how the acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree, recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase, and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. This Statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. An entity may not apply it before that date. We may experience a financial statement impact depending on the nature and extent of any new business combinations entered into after the effective date of SFAS No. 141(R).

In December 2007, FASB issued SFAS No. 160, which amends Accounting Research Bulletin (ARB) No. 51 and (1) establishes standards of accounting and reporting on noncontrolling interests in consolidated statements, (2) provides guidance on accounting for changes in the parent's ownership interest in a subsidiary, and (3) establishes standards of accounting of the deconsolidation of a subsidiary due to the loss of control. The amendments to ARB No. 51 made by SFAS No. 160 are effective for fiscal years (and interim period within those years) beginning on or after December 15, 2008. The Company is currently assessing the potential impact this statement on its financial statements.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES (Continued)

Recent Accounting Pronouncements (Continued)

In January 2008, the SEC issued **Staff Accounting Bulletin** (SAB) No. 110, which amends SAB No. 107. In March 2005, the SEC issued **Staff Accounting Bulletin** (SAB) No. 107 in which, among other matters, the Staff expressed its views regarding the valuation of share-based payment arrangements. Specifically, SAB No. 107 provided a simplified approach for estimating the expected term of a plain vanilla option, which is required for application of the Black-Scholes-Merton model (and other models) for valuing share options. At the time, the Staff acknowledged that, for companies choosing not to rely on their own historical option exercise data, information about exercise patterns with respect to plain vanilla options granted by other companies might not be available in the near term; accordingly, in SAB No. 107, the Staff permitted use of a simplified approach for estimating the term of plain vanilla options granted on or before March 31, 2008. The information concerning exercise behavior that the Staff contemplated would be available by such date has not materialized for many companies. Thus, in SAB No. 110, the Staff continues to allow use of the simplified rule for estimating the expected term of plain vanilla options until such time as the relevant data do become widely available. The Company does not expect the effects of this bulletin to have any affect on its financial statements at this time.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133*, which changes the disclosure requirements for derivative instruments and hedging activities. Enhanced disclosures are required to provide information about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. This Statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. This Statement will require the additional disclosures described above.

NOTE 3 EQUITY COMPENSATION PLANS

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, 2008 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.

At June 30, 2007, Company had 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, 2007.

On February 27, 2008, the Board of Directors adopted the 2008 Equity Plan (the Plan). 1,000,000 shares of common stock are reserved under the Plan for the grant of stock options or issuance of stock bonuses to compensate new, continuing, and existing employees, officers, consultants, and advisors of the Company.

Concurrent with the adoption of the Plan, the Company granted options to purchase an aggregate of 775,000 shares of common stock to various officers, directors, employees, and consultants. 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 58%, risk free interest rates of 2.25% and expected life of 3.3 years.

NOTE 3 EQUITY COMPENSATION PLANS (Continued)

The options vest over a 3 year period on September 30th of each year subject to the achievement of several goals. These performance goals require specified increases in proved oil and gas reserves, present value of reserves, production, and net income, in each case as compared to the base year ended June 30, 2007. Achievement of the goals will be determined by the Company s audited financial statements and independent reserve report as of the fiscal year end immediately preceding each vesting date.

The grant date fair value of these options is approximately $704,000. Total compensation cost related to these unvested awards is approximately $465,000, net of taxes, and will be recognized over the three-year vesting period when, and if the performance goals are, or are likely to be achieved.

Stock compensation expense for the three and nine months ended March 31, 2008 and 2007 was $0 and $47,298 and $27,500 and $109,008, respectively. This expense did not have a significant effect on diluted earnings per share for the quarter, or year-to-date periods ended March 31, 2008 and 2007.

NOTE 4 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 5 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.

Aspen is paid $50,000 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 agreed to purchase 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 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. On February 26, 2008, the Company entered into a subsequent renewal of the contract to sell 2,000 MMBTU per day to Enserco, 1,000 MMBTU per day at a fixed price of $8.61 and the remaining 1,000 MMBTU at $8.81. The current renewal of the Enserco contract is for a term of April 1, 2008 through October 31, 2008.

NOTE 5 CONTINGENCIES AND DRILLING COMMITMENTS (Continued)

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.

In addition, the Company and Calpine Producer Services, L.P. entered into an agreement whereby Calpine will purchase, and Aspen will deliver 500 MMBTU per day less transportation and other expenses for $8.80 per MMBTU under terms and conditions similar to those described above. The Calpine contract expires October 31, 2008.

Aspen acquired a 12-square mile 3D-seismic survey directly south of Aspen s successful West Grimes project in Colusa County, California. The new Strain Ventures project encompasses parts of the West Grimes and Buckeye Gas Fields, and includes a sparsely drilled area west of these fields. Aspen anticipates several prospects will be identified on the new 3D-survey, some of which may be scheduled for drilling in the fall of 2008. Aspen has a 32% working interest in the Strain Ventures project.

Aspen has agreed to participate in a new exploration program operated by a third party in the Malton area in Glenn and Tehama Counties, California. This area is east of Aspen s Malton Black Butte project. Several prospects have been identified by the Operator in this area, and drilling is scheduled to begin in spring, 2008. Aspen has agreed to acquire a non-operated 7% Working Interest in the project.

Aspen has drilled the Johnson 13 well in its Johnson Unit of the Malton Black Butte Field. This well is in the same Unit as our Johnson 11 well completed in August 2005. Aspen has a 31% working interest in the Johnson Unit but a lesser interest in the Elektra Unit which overlaps a portion of the Johnson Unit. Aspen is attempting to define its interests in those wells and has not commenced producing from the Johnson 13 well. As noted in the Risk Factors of Aspen s Form 10-KSB, the existence of a title deficiency can adversely impact the economic results of even a successful well. To the extent that it proves that Aspen s interests in the Johnson 11 and Johnson 13 wells are impacted by the overlapping Elektra unit, Aspen (as operator of the wells) will likely have to make certain economic adjustments although those will be determined later based on a full legal review.

In February 2007, Aspen purchased an interest in 33 producing gross oil wells (4.125 net) 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. Through December 2007, Aspen was obligated to pay 12.5% of the expenses of operations for a 10% working interest. Since Aspen s investment did not reach payout as of January 1, 2008, Aspen s expense obligation was reduced to 10%. At payout, Aspen s working interest will proportionately be reduced also. Commencing February 2008, Aspen (and the other working interest participants) agreed that the operator could retain 60% of the cash flow from the producing wells (after deduction of royalties, taxes, expenses and loan payment) for capital projects, geology and engineering. Additionally, in May 2008 Aspen amended its participation agreement in the Poplar Unit to separately market and deal with the deeper rights, oil and gas rights below the base of the Mission Canyon Formation and to grant one of the participants the right to seek to farmout the deeper rights.

To the extent that Aspen has available capital and has identified other appropriate drilling or exploration opportunities, Aspen may participate in the drilling of additional wells.

For the period January 1 through June 30, 2008, Aspen estimates that Aspen s share of seismic acquisition, drilling, and completion costs will be as follows. This does not include the share that Aspen may bill to other working interest participants where Aspen operates the wells.

Area	3D-Seismic Acauisition	Wells	Drilling Costs	Completion & Equipping Costs	Total
West Grimes Gas Field Colusa County, CA	$ -	3	$ 585,000	$ 405,000	$ 990,000
Malton Gas Field Glenn and Tehama Counties, CA	150,000	4	120,000	90,000	360,000
Malton Farmout wells Sutter and Glenn Counties, CA	-	3	472,500	307,500	780,000
Total Expenditure	$ 150,000	10	$ 1,177,500	$ 802,500	$ 2,130,000

NOTE 6 **<u>LONG-TERM DEBT</u>**

In January 2007, the Company 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 in northern Montana. 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 5.85% . Principal of $16,667 plus interest payments are due monthly through January 15, 2010. As collateral for this indebtedness, we granted the bank a security interest on our Accounts Receivables. At March 31, 2008 the outstanding balance on the note was $366,667 of which $200,000 is classified as current.

The Wells Fargo note contains restrictive covenants which, among other things, require 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.

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 is due monthly through February 25, 2009. At March 31, 2008, the outstanding balance was $293,750, all of which is classified as current.

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, 2008 and 2007 and our financial condition, liquidity and capital resources as of March 31, 2008 and June 30, 2007. 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, 2007. 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 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, and in 2007 we acquired interests in oil properties in Montana. Our business activities are primarily focused in two separate aspects of the oil and gas industry:

(1) holding and acquiring operating interests in oil and gas properties where we act as the operator of oil and gas wells and properties; and

(2) holding non-operating interests in oil and gas properties.

We are currently the operator of 66 gas wells in the Sacramento Valley of northern California. Additionally, we have a non-operated interest in 22 gas wells in the Sacramento Valley of northern California and non-operating working interest in approximately 37 oil wells in Montana. When appropriate we may engage in business activities related to the exploration and development of other minerals and resources.

During the period ended March 31, 2008, our working capital reduced from about $2 million at June 30, 2007 to about $1.4 million as of March 31, 2008. Working capital decreased due to a $435,800 decrease in the fair value of marketable securities available for sale and reclassification of $237,500 of Notes payable from non-current to current because the remaining outstanding balance is due within one year (February 25, 2009).

Although our revenues from oil and gas sales increased during the nine months ended March 31, 2008 as compared to the same periods in 2007, operating expenses increased more than revenues, resulting in a lesser income from operations and net income during 2008 as compared to 2007.

Where possible, we attempt to be the operator of each property in which we invest. We believe that our knowledge of drilling and operating wells in the Sacramento Valley allows us to maximize the potential return of each property. In addition, the other working interest owners are obligated to pay us fees pursuant to the overhead reimbursement provisions of the COPAS Accounting Procedures which are included as an attachment to the operating agreements. These accounting procedures define the overhead expenses that are charged to the joint accounts and permit us to charge some expenses (such as salaries, wages and Personal Expenses of Technical Employees directly employed on the Joint Property and drilling expenses) directly to the joint interest owners. In almost all cases, Aspen also charges a general monthly producing overhead rate per well. We do not recognize these fees received from the joint interest owners as revenues; rather they are offset against (and are a deduction from) our general and administrative expenses as reflected in our statement of operations. During the three and nine months ended March 31, 2008, these administrative charges to the properties helped cover approximately 47% and 55% of our selling, general and administrative expenses as compared to 58% and 37% for the same periods of the 2007 fiscal year due primarily to decreases in the issuance of equity instruments as compensation for services, while management fees decreased 29% and increased 13%, respectively. Management fees as a percentage of our selling, general and administrative expenses (SG&A) increased 18% for the nine month period ending March 31, 2008 compared to 2007 because the Company operated 8 more wells than in the prior period.

Outlook and Trends

Our financial performance for the remaining portion of our 2008 fiscal year and into 2009 depends on a variety of factors set forth herein and in our Form 10-KSB for the year ended June 30, 2007 including our production, prices received for our production, and our operating and other expenses. 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. Management uses the measurement of our produced reserves to help measure the success of our exploration and development activity. Where reserves are replaced in an amount greater than production, it is a sign that we are continuing our exploration and development activity successfully. A one-year decline or increase may not be important to investors, but seeing a decline or increase over a several year period is a trend worthy of noting, both internally by management and externally by investors.

We have entered into contracts with Enserco Energy, Inc. and Calpine Producer Services, L.P. to sell about 30% of our production from April 1, 2008 through October 31, 2008. We expect to have sufficient gas available for delivery to Enserco from anticipated production from our California fields.

Quantitative and Qualitative Disclosure About Risk

Our ability to replace reserves, dissipated through production or recalculation, will depend largely on how successful our drilling and acquisition efforts will be in the future. While we cannot predict the future, our historic success drilling ratio over the past 7 years has been 87%. With the use of 3-D seismic and well control data, interpreted by our geological and geophysical consultants, we feel we can manage our dry hole risk adequately.

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, and have recently entered into a similar contract with Calpine. Under the current renewal of the Enserco contract, we are contractually obligated to deliver 2,000 MMBTU per day to Enserco, including 1,000 MMBTU at $8.61 per MMBTU, and 1,000 MMBTU per day at $8.81. The term of the Enserco contract is through October 31, 2008. Under the Calpine contract, we are obligated to deliver 500 MMBTU per day at $8.80 per MMBTU through October 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. During the year ended June 30, 2007, we borrowed $600,000 to purchase an interest in the Poplar Field and became obligated for an additional $375,000 indebtedness as part of that purchase.

Our principal uses of cash are for operating expenses, the acquisition, drilling, completion and production of prospects, the acquisition of producing properties, working capital and servicing debt.

During the first nine months of our 2008 fiscal year, we received approximately $1.7 million of cash in our operations, investing activities and financing activities as compared to using $3.3 million during the same period of our 2007 fiscal year. The most significant change resulting in the increase in cash was cash flows from operations as described in the next paragraph. We used about $1 million less cash in investing activities during the nine months ended March 31, 2008 than during the prior year, and approximately $400,000 more in financing activities during the nine months ended March 31, 2008 as compared to the same period of our prior fiscal year.

We generated cash of $4.8 million from operations for the nine months ended March 31, 2008, as compared to $353,000 for the nine months ended March 31, 2007. This positive change of approximately $4.5 million was primarily due to cash received for a drilling project in which Aspen has decided not to participate as the operator. Those funds (approximately $4.3 million) are reflected in accounts payable and will be transferred to the new operator as soon as the change is finalized. The decrease in cash used to pay current liabilities during the period impacts cash flows immediately in that less cash was used in the period to satisfy those liabilities; however, the increase is due to the timing of payments, and cash will be used to satisfy those liabilities in the near term. In addition, the Company received $600,000 cash from the sale of trading securities during the 2007 period, which have now been classified as available for sale, and there was a decrease in accounts receivable ($181,000 in 2008 compared to an increase of $156,000 in 2007).

Investing activities used cash to increase capitalized oil and gas costs of $2.6 million for the nine months ending March 31, 2008 as compared to $2.7 million in the nine months ended March 31, 2007. These expenditures are net of the sale of interests in wells to be drilled charged to third party investors. In addition, we invested $300,000 in municipal bonds in the current period.

Our working capital surplus (current assets less current liabilities) at March 31, 2008, was $1.4 million, which reflects a $658,000 decrease from our working capital at June 30, 2007. Working capital decreased due to a $435,800 decrease in the fair value of marketable securities available for sale and reclassification of $237,500 of Notes payable from non-current to current because the remaining outstanding balance is due within one year (February 25, 2009).

Planned Oil and Gas Operations

We are in the planning stage for our oil and gas operations that are anticipated to occur during the 2008 drilling season. We are participating in a 3-Dimensional seismic survey in the Strain Ventures prospect in our West Grimes gas field. We are also planning to participate in the drilling of several gas wells but (as mentioned above) we do not expect to engage in any significant drilling operations during the remainder of our fiscal year. Our planning is still at an early stage, and the estimates set forth below are merely estimates based on the best information we currently have. As is typically the case with oil and gas operations, drilling a well may provide us better information about the location for and costs of subsequent wells in the same area. In addition, better opportunities may present themselves to us, causing us to defer anticipated drilling for these other opportunities. The following table sets forth our share of the estimated costs to complete this program:

Area	3D-Seismic Acquisition	Wells	Drilling Costs	Completion & Equipping Costs	Total
West Grimes Gas Field Colusa County, CA	$ -	3	$ 585,000	$ 405,000	$ 990,000
Malton Gas Field Glenn and Tehama Counties, CA	150,000	4	120,000	90,000	360,000
Malton Farmout wells Sutter and Glenn Counties, CA	-	3	472,500	307,500	780,000
Total Expenditure	$ 150,000	10	$ 1,177,500	$ 802,500	$ 2,130,000

We also expect to incur expenses in connection with our Poplar Field prospect in Montana, and the operator is withholding 60% of the net revenues attributable to our interest for anticipated capital expenses, geology and engineering. A total of $30,146 has been withheld through March 31, 2008. We do not expect significant capital expenditures in the Poplar Field to be incurred through the end of our fiscal year. The operator is preparing for its summer and fall drilling program, which amounts have not yet been quantified. We anticipate that our existing working capital and anticipated cash flow from operations and future successful drilling activities will be sufficient to finance our drilling and operating expenses estimated in the foregoing table and as we may otherwise plan for the next twelve months. Oil prices and gas prices are affected by national and international concerns. As a result, 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, we believe 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, 2008 Compared to March 31, 2007

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 2008 and 2007:

	For the Nine Months Ended	
	March 31, 2008	March 31, 2007
Total Revenues	100.0%	100.0%
Oil and Gas Production Costs	26.8%	17.2%
Gross Profit	73.2%	82.8%
Cost and Expenses		
Depreciation and depletion	48.8%	45.5%
Selling, general and administrative	9.3%	19.6%
Total Cost and Expenses	84.9%	82.3%
Income from Operations	15.1%	17.7%
Other Income and Expenses	1.5%	21.6%
Income Before Income Taxes	16.6%	39.3%
Provision for Income Taxes	-3.4%	-8.5%
Net Income	13.2%	30.8%

To facilitate discussion of our operating results for the nine months ended March 31, 2008 and 2007, we have included the following selected data from our Condensed Consolidated Statements of Operations:

	Comparison of the Fiscal Nine Months Ended March 31,		Increase (Decrease)	
	2008	2007	Amount	Percentage
Revenues:				
Oil and gas sales	$ 3,910,858	$ 3,361,563	$ 549,295	16%
Cost and Expenses:				
Oil and gas production	1,047,302	576,534	470,768	82%
Depreciation and depletion	1,910,003	1,528,330	381,673	25%
Selling, general and administrative	363,333	660,247	(296,914)	-45%
Total Costs and Expenses	3,320,638	2,765,111	555,527	20%
Operating Income	590,220	596,452	(6,232)	-1%
Other Income (Expenses)	59,886	725,688	(665,802)	-92%
Income Tax Benefit (Provision)	(133,439)	(287,393)	153,954	-54%
Net Income (Loss)	$ 516,667	$ 1,034,747	$ (518,080)	-50%

In general, our operations have been adversely affected by increasing costs of production and accretion, depletion, depreciation, and amortization; however, the recent increase in oil and gas prices and production have produced net income for the nine months ended March 31, 2008, although reduced by about one-half as compared to the nine month period ended March 31, 2007. 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 ended March 31, 2008, our operations continued to be focused on the production of oil and gas, in California and Montana. Our gas production decreased from 488,000 MMBTU sold during the nine months ending March 31, 2007, to 462,027 MMBTU sold in the current period (an decrease of approximately 5%). Prices received however increased approximately 6% over the same period last fiscal year. As a result of our increased prices during the first nine months of our 2008 fiscal year, and the acquisition of oil properties in Montana, our revenues from oil and gas sales increased during the 2008 period by approximately $500,000 from approximately $3.4 million to approximately $3.9 million.

Oil and gas production costs increased 82% in the nine months ended March 31, 2008, as compared to the same period in 2007, from approximately $577,000 to almost $1,050,000. The increase can be attributed to the addition of gas wells, and our percentage working interests in these wells were somewhat higher than the average of wells owned at March 31, 2007. Additionally, all of the costs for the service companies who perform work on Aspen's wells have increased dramatically. Aspen is attempting to address these costs, but these costs are driven by market conditions and Aspen s ability to control these costs is minimal. Generally the costs increase as prices received for oil and natural gas increase, but costs may increase more quickly than the prices received.

Depletion, depreciation and amortization expense increased 25%, from approximately $1,528,000 for the nine months ended March 31, 2007 as compared to $1,910,000 million during the 2008 period. This increase was the result of increased investments in oil and gas activities, which resulted in the higher total depletion taken. Depletion expense per equivalent unit of production (MCFe) was $3.75 and $3.06 for the nine months ending March 31, 2008 and 2007, respectively.

When the Company acts as operator for our producing wells, we receive management fees for these services, which serve to offset our SG&A expenses. When comparing SG&A for the first nine months of 2008 and 2007, costs decreased by $296,414, or 45%, due primarily to decreases in the issuance of equity instruments as compensation for services, while management fees increased 13%. Management fees as a percentage of SG&A increased 18% for the period ending March 31, 2008 compared to 2007.

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 increased from approximately 37% during the nine months ended March 31, 2007 to approximately 55% at March 31, 2008.

		March 31, 2008		March 31, 2007
Management fees	$	436,727	$	386,818
Selling, general and administrative (SG&A)		800,060		1,047,065
Management fees as a percentage of SG&A		54.6 %		36.9%

Central to an understanding of our financial statements for the nine months operations ended March 31, 2008 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:

		Gas Sales		MMBTU Sold		Price/ MMBTU		Oil & NGL Sales		Bbls Sold		Price/ Bbl
2008												
1st Quarter	$	1,057,907		170,058	$	6.22	$	162,915		2,256	$	72.21
2nd Quarter		1,132,137		162,281		6.98		232,638		2,856		81.44
3rd Quarter		1,063,473		129,688		8.20		261,788		2,822		92.77
Year to date		3,253,517		462,027		7.04		657,341		7,934		82.85
June 30, 2007												
lst Quarter		958,171		158,391		6.05		4,762		67	$	71.07
2nd Quarter		1,051,640		156,003		6.74		2,198		31		70.90
3rd Quarter		1,239,895		173,623		7.14		104,896		1,831		57.29
4th Quarter		936,122		143,540		6.52		120,547		2,057		58.60
June 30, 2007	$	4,185,828		631,557	$	6.63	$	232,403		3,986	$	58.30
Nine-Month Change												
Amount	$	3,811	$	(25,990)	$	0.38	$	545,485	$	6,005	$	24.86
Percentage		0.1%		-5.3%		5.7%		487.7%		311.3%		42.9%

Oil and gas revenue and volumes sold of our product have shown an increase over the nine months of fiscal 2008. As the table above notes, gas revenue has increased approximately .1% when comparing the nine-month periods ended March 31, 2008 and 2007. Volumes sold decreased approximately 5.3%, while the price received for our gas product increased 5.7% . The significant increase in oil revenue is due to the acquisition of working interests in oil wells in Montana in the third quarter of fiscal 2007.

Contractual Obligations

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 agreed to purchase 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 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. On February 26, 2008, the Company entered into a subsequent renewal of the contract to Enserco 1,000 MMBTU per day at a fixed price of $8.61 and 1,000 MMBTU at $8.81 for the term of April 1, 2008 through October 31, 2008.

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In addition, the Company and Calpine Producer Services, L.P. entered into an agreement whereby Calpine will purchase, and Aspen will deliver 500 MMBTU per day less transportation and other expenses for $8.80 per MMBTU under terms and conditions similar to those described above.

We expect to have sufficient gas available for delivery to Enserco and Calpine from anticipated production from our California fields. Aspen s sales of natural gas under the contracts qualify for the Normal Purchases and Normal Sales exception in paragraph 10(b) of FAS 133. The contracts are normal industry sales contracts that provide for the sale of gas over a reasonable period of time in the normal course of business.

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 are a significant component of oil and natural gas properties, but do 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 2008 or the comparable period in 2007.

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.

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, 2008, as all receivables are expected to be collected in full.

Investments in Debt and Equity Securities

Prior to the beginning of the current fiscal year, the Company classified all investments as Trading Securities in accordance with SFAS No. 115, *Accounting for Certain Investments in Debt and Equity Securities*. These securities were marked to market each period with the realized and unrealized gain or loss recorded in the statement of operations. During the current quarter, management reassessed the appropriateness of the classification of the securities held, and determined that due to the sufficiency of cash flows to finance current operations and budgeted expenditures, the Company will hold investments until such time it determines there may be a need to sell those securities. As of July 1, 2007, Management determined the securities are more appropriately classified as available for sale, and changes in the fair value of the securities are reported as a separate component of shareholders equity until realized. The securities were transferred from the trading category, and as such, the unrealized holding gain or loss at the date of the transfer has already been recognized in earnings and shall not be reversed.

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 7%. 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 nine month period ended March 31, 2008 the Company recorded income tax provision of $133,439. 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.

Other Developments

The Johnson Unit #13 well, located in the Malton Black Butte Field, Tehama County, California, was drilled to a depth of 4,896 feet and encountered approximately 125 feet of potential gross gas pay in several intervals in the Forbes formation. This well is currently shut in awaiting completion. Aspen has a 31% operated working interest in this well.

The SJDD #11-1 well, located in the Cache Creek Gas Field, Yolo County, California, was drilled to a depth of 4,111 feet and encountered approximately 24 feet of potential gross gas pay in several intervals in the Starkey formation. One of these intervals was perforated and tested gas on a 10/64 choke at a stabilized flow rate of 750 MCFPD and 1380 psig flowing casing pressure. The shut in tubing pressure was 1440 psig and shut in casing pressure was 1500 psig. Aspen has a 30% operated working interest in this well.

As noted in the Company's Form 8-K, filed on January 16, 2008, the Board of Directors of Aspen Exploration Corporation appointed R.V. Bailey, vice president and chairman of Aspen s Board of Directors, as Aspen s interim chief executive officer, and Kevan B. Hensman, a director of Aspen, as Aspen s interim chief financial officer. The Board also changed Mr. Bailey s title to vice president of exploration and administration, and appointed Mr. Hensman as vice president of operations and finance. These changes were made because Robert A. Cohan, President of Aspen who formerly held those positions, has been stricken by a stroke. Mr. Cohan is still participating in Aspen as a member of the board of directors and will work with Messrs. Bailey and Hensman and Aspen s consultants, as he is able, to ensure that Aspen s oil and gas operations continue. The board of directors has determined that these appointments are temporary until such time as Mr. Cohan is able to resume his duties.

Forward Looking Statements

The management discussion and analysis portion of this report contain forward-looking statements (as such term is defined in Section 21E of the Securities Exchange Act of 1934, as amended). These statements reflect our current expectations regarding our possible future results of operations, performance, and achievements. These forward-looking statements are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. Wherever possible, we have tried to identify these forward-looking statements by using words such as anticipate, believe, estimate, expect, plan, intend, and similar expressions.

These items are discussed at length in Aspen s Form 10-KSB filed with the Securities and Exchange Commission, under the heading Risk Factors 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 3A(T). CONTROLS AND PROCEDURES

As of March 31, 2008, we have carried out an evaluation under the supervision of, and with the participation of our interim Chief Executive Officer and our interim Chief Financial 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, 2008, our interim Chief Executive Officer and our interim Chief Financial Officer have 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 that occurred during the quarter ended March 31, 2008 or subsequently, and have not been reported on a current report on Form 8-K.

On February 2008, the Company granted an aggregate of 750,000 options to purchase the Company s common stock to employees, directors, and consultants. The options were granted pursuant the Company s 2008 Equity Plan. The material terms of the option grants and the information required by Item 701 are provided below:

(a) Effective February 27, 2008 we granted an aggregate of 750,000 options to Company employees, directors, and consultants. Except for the number of options granted, the material terms of each option grant were the same. The exercise price of each option is $2.14, the closing sales price of the Company s common stock on February 27, 2008. Each of the options expires on February 27, 2013 (five years after the date of grant). All of the option grants vest over three years on a pro-rata basis on September 30, 2008, September 30, 2009, and September 30, 2010, but only upon the achievement of certain defined Company performance goals. These performance goals require specified increases in:

proved oil and gas reserves (total barrels of oil equivalent),
present value of reserves (10% discount),
production (total barrels of oil equivalent),
and net income,

in each case as compared to the base year ended June 30, 2007. The options do not qualify as incentive stock options under Section 422 of the Internal Revenue Code.

(b) There was no placement agent or underwriter for the transaction.

(c) The stock options were granted in consideration for services provided to the Company. The Company received no cash for the grant of the options.

(d) We relied on the exemption from registration provided by Section 4(2) under the Securities Act of 1933 for the grant of the stock options. We did not engage in any public advertising or general solicitation in connection with this transaction, and we provided each recipient with disclosure of all aspects of our business, including our reports filed with the Securities and Exchange Commission, our press releases, access to our auditors, and other financial, business, and corporate information. We believe that each recipient obtained all information regarding Aspen he or she requested, received answers to all questions he or she (and their advisors) posed, and otherwise understood the ris ks of accepting our securities for investment purposes.

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

Item 3. DEFAULTS UPON SENIOR SECURITIES

None.

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

No matter was submitted during the third 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
31.1	Certification Pursuant to Section 302 of the Sarbanes -Oxley Act of 2002.
31.2	Certification Pursuant to Section 302 of the Sarbanes -Oxley Act of 2002.
32.1	Certification Pursuant to 18 U.S.C. §1350, as Adopted Pursuant to Section 906 of the Sarbanes -Oxley Act of 2002.
32.2	Certification Pursuant to 18 U.S.C. §1350, as Adopted Pursuant to Section 906 of the Sarbanes -Oxley Act of 2002.

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 13, 2008

/s/ R.V. Bailey
R.V. Bailey, interim Chief Executive Officer
(principal executive officer)

Date: May 13, 2008

/s/ Kevan B. Hensman
Kevan B. Hensman, interim Chief Financial Officer
(principal financial officer)