ASPEN EXPLORATION CORP
Form 10QSB
May 12, 2004

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, 2004

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 12, 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 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 12, 2004
Common stock, $.005 par value	5,863,828

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

ASSETS

	March 31, 2004 (Unaudited)	June 30, 2003
Current Assets:		
Cash and cash equivalents, including $475,500 and $516,365 of invested cash at March 31, 2004 and June 30, 2003, respectively	$ 533,998	$ 776,566
Precious metals	18,823	18,823
Accounts receivable, trade	292,782	269,259
Accounts receivable - related party	21,224	6,302
Prepaid expenses	9,525	22,181
Total current assets	876,352	1,093,131
Investment in oil and gas properties, at cost (full cost method of accounting)	7,650,360	6,723,579
Less accumulated depletion and valuation allowance	(3,047,469)	(2,674,469)
	4,602,891	4,049,110
Property and equipment, at cost:		
Furniture, fixtures and vehicles	112,562	112,562
Less accumulated depreciation	(77,953)	(64,178)
	34,609	48,384
TOTAL ASSETS	$ 5,513,852	$ 5,190,625

(Statement Continues)
See notes to Condensed Consolidated Financial Statements

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

LIABILITIES AND STOCKHOLDERS' EQUITY

	March 31, 2004 (Unaudited)	June 30, 2003
Current liabilities:		
Accounts payable and accrued expenses	$ 136,944	$ 581,895
Accounts payable - related party	21,099	17,685
Advances from joint owners	480,864	150,821

Notes payable - current	150,000	-0-
Total current liabilities	788,907	750,401
Asset retirement obligation	45,081	17,841
Deferred income tax payable - long term	131,350	131,350
Notes payable - long term	37,500	-0-
Total long term liabilities	213,931	149,191
Total liabilities	1,002,838	899,592
Stockholders' equity:		
Common stock, $.005 par value:		
Authorized: 50,000,000 shares		
Issued: At March 31, 2004: 5,863,828		
and June 30, 2003: 5,863,828	29,320	29,320
Capital in excess of par value	6,025,797	6,025,797
Accumulated deficit	(1,536,919)	(1,756,900)
Deferred compensation	(7,184)	(7,184)
Total stockholders' equity	4,511,014	4,291,033
Total liabilities and stockholders' equity	$ 5,513,852	$ 5,190,625

See Notes to Condensed Consolidated Financial Statements

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

	Three Months Ended March 31,		Nine Months March 3
	2004	2003	2004
Revenues:			
Oil and gas	$ 401,941	$ 314,222	$ 1,106,809
Management fees	38,613	22,323	150,634
Interest and other, net	(427)	931	4,338
Total Revenues	440,127	337,476	1,261,781
Costs and expenses:			
Oil and gas production	85,912	64,700	188,301
Depreciation, depletion and amortization	127,575	108,656	385,524
Selling, general and administrative	146,800	135,372	464,026
Interest expense	3,078	-0-	3,949
Total Costs and Expenses	363,365	308,728	1,041,800
Income (loss) before taxes	76,762	28,748	219,981

Provision for income taxes	(--)	(--)	(--)	
Net income (loss)	$ 76,762	$ 28,748	$ 219,981	$
Basic earnings (loss) per common share	$ .01	$ --	$ .04	$
Diluted earnings (loss) per common share	$ .01	$ --	$ .04	$
Basic weighted average number of common shares outstanding	5,863,828	5,863,828	5,863,828	
Diluted weighted average number of common shares outstanding	5,951,553	5,863,828	5,951,553	

See Notes to Condensed Consolidated Financial Statements

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

	Nine months ended March 31, 2004	2003
Cash flows from operating activities:		
Net income (loss)	$ 219,981	$ (31,150)
Adjustments to reconcile net income (loss) to net cash provided used by operating activities:		
Depreciation, depletion and amortization	385,524	292,045
Amortization of deferred compensation	-0-	3,375
Changes in assets and liabilities:		
Decrease (increase) in receivable	(38,445)	77,162
Decrease in prepaid expense	12,656	4,928
Increase (decrease) in accounts payable and accrued expense	(111,494)	494,233
Net cash provided by operating activities	468,222	840,593
Cash flows from investing activities:		
Additions to oil and gas properties	(1,033,040)	(626,385)
Proceeds - sale of oil and gas properties	134,750	69,422
Proceeds - sale of idle equipment	-0-	1,155
Net cash (used) by investing activities	(898,290)	(555,808)
Cash flow from financing activities:		

Proceeds from notes payable	225,000	-0-
Payment of notes payable	(37,500)	-0-
	187,500	-0-
Net increase (decrease) in cash and cash equivalents	(242,568)	284,785
Cash and cash equivalents, beginning of period	776,566	916,001
Cash and cash equivalents, end of period	$ 533,998	$ 1,200,786
Other information:		
Interest paid	$ 3,949	$ 479
Non-cash investing activities		
Asset retirement obligation	$ 28,491	$ 0

See Notes to Condensed Consolidated Financial Statements

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ASPEN EXPLORATION CORPORATION

Notes to Condensed Consolidated Financial Statements
(Unaudited)

March 31, 2004

Note 1 BASIS OF PRESENTATION

The accompanying financial statements are unaudited. However, in our opinion, the accompanying financial statements reflect all adjustments, consisting of only normal recurring adjustments, necessary for fair presentation. Interim results of operations are not necessarily indicative of results for subsequent interim periods or the remainder of the year. These financial statements should be read in conjunction with our Annual Report on Form 10-KSB for the year ended June 30, 2003.

Except for the historical information contained in this Form 10-QSB, this Form contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those discussed in this Report. Factors that could cause or contribute to such differences include, but are not limited to, those discussed in this Report and any documents incorporated herein

by reference, as well as the Annual Report on Form 10-KSB for the year ended June 30, 2003.

Note 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No.

141, "Business Combinations," which requires the purchase method of accounting for business combinations initiated after June 30, 2001 and eliminates the pooling-of-interests method. In July 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets," which discontinues the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review for impairment. Intangible assets with a determinable useful life will continue to be amortized over that period. The oil and gas industry is currently discussing the appropriate balance sheet classification of oil and gas mineral rights held by lease or contract. We classify these assets as a component of oil and gas properties in accordance with its interpretation of SFAS No. 19 and common industry practice. There is also a view that these mineral rights are intangible assets as defined in SFAS No. 141, "Business Combinations", and, therefore, should be classified separately on the balance sheet as intangible assets.

In March 2004, the Emerging Issues Task Force ("EITF") reached a consensus that mineral rights, as defined in EITF Issue No. 04-2, "Whether Mineral Rights Are Tangible or Intangible Assets," are tangible assets and that they should be removed as examples of intangible assets in SFAS No. 141, "Business Combinations" and No. 142, "Goodwill and Other Intangible Assets". The FASB has recently ratified this consensus and directed the FASB staff to amend SFAS Nos. 141 and 142 through the issuance of FASB Staff Position FAS Nos. 141-1 and 142-1. Historically, Aspen has included the costs of such mineral rights as tangible assets, which is consistent with the EITF's consensus. As such, EITF 04-02 has not affected the Company's consolidated financial statements.

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Note 3   RECEIVABLE - RELATED PARTIES

The receivable from related parties constitutes amounts due from officers and consultants for joint operating costs of wells operated by us. The transactions are in the normal course of business with the same terms as other joint owners and are repaid in a normal business cycle.

Note 4   ASSET RETIREMENT OBLIGATION

Effective July 1, 2002, we adopted the provisions of SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 generally applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 requires us to recognize an estimated liability for the plugging and abandonment of our gas wells. We have recognized the future cost to plug and abandon the gas wells over the estimated useful lives of the wells in accordance with SFAS No. 143. A liability for the fair value of an asset retirement obligation with a corresponding increase in the carrying value of the related long-lived asset is recorded at the time a producing well is purchased or a drilled well is completed and ready for production. We will amortize the amount added to the oil and gas properties and recognize accretion expense in connection with the discounted liability over the remaining life of the respective well. The estimated liability is based on historical experience in plugging and abandoning wells, estimated useful 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 a discounted liability using a credit adjusted risk-free rate of 6%. Revisions to the liability could occur due to changes in plugging and abandonment costs, useful well lives or if federal or state regulators enact new regulations on the plugging and abandonment of wells.

A reconciliation of our liability for the year ended March 31, 2004 is as follows:

Asset retirement obligations as of June 30, 2003	$ 17,841
ARO additions	29,007
Liabilities settled	(516)
Accretion expense	857
Revision of estimate	(2,108)
Asset retirement obligation as of March 31, 2004	$ 45,081

Note 5 EARNINGS PER SHARE

We follow Statement of Financial Accounting Standards ("SFAS") No. 128, addressing earnings per share. SFAS No. 128 established the methodology of calculating basic earnings per share and diluted earnings per share. The calculations differ by adding any instruments convertible to common stock (such as stock options, warrants, and convertible preferred stock) to weighted average shares outstanding when computing diluted earnings per share.

Note 5 EARNINGS PER SHARE (CONTINUED)

The following is a reconciliation of the numerators and denominators used in the calculations of basic and diluted earnings per share. We had a net income of $219,981 for the nine months ended March 31, 2004 and a net loss of $31,150 for the nine months ended March 31, 2003. Because of the net loss for the nine months ended March 31, 2003, the basic and diluted average outstanding shares are considered the same, since including the dilutive shares would have an antidilutive effect on the loss per share calculation.

	Nine months ended March 31, 2004		
	Net Income	Shares	Per Share Amount
Basic earnings per share:			
Net income and share amounts	$ 219,981	5,863,828	$ .04
Dilutive securities: stock options	--	676,000	--
Repurchased shares	--	(588,275)	--
Diluted earnings per share:			
Net income and assumed share conversion	$ 219,981	5,951,553	$ .04

Note 6 STOCKHOLDERS' EQUITY

Stock Options

On March 2, 2000, stock options were granted to the President of Aspen Power Systems, LLC for 100,000 shares of the Company's common stock at a grant price of $0.625 per share. These options vest 25,000 shares per annum from March 15, 2000 through March 15, 2003. The options are exercisable through March 15, 2004. As of this filing, no options were exercised, and the options have expired.

As of March 31, 2004, we had an aggregate of 676,000 common shares reserved for issuance under our stock option plans. These plans provide for the issuance of common shares pursuant to stock option exercises, restricted stock awards and other equity based awards.

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Note 6 STOCKHOLDERS' EQUITY (CONTINUED)

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

	Number of Shares	Weighted Average Exercise Price of Shares Under Plans
Outstanding balance June 30, 2003	776,000	$ .58
Granted	-0-	--
Exercised	-0-	--
Forfeited or expensed	(100,000)	.625
Outstanding balance March 31, 2004	676,000	$ .57

The following table summarizes information concerning outstanding and exercisable options as of March 31, 2004:

	Outstanding			Exercisable	
Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life In Years	Weighted Average Exercisable Price	Number Exercisable	Weighted Average Exercise Price
$.57	426,000	08/15/2005(1)	$ .57	-0-	$ .57
.57	250,000	08/15/2007(1)	.57	-0-	.57
	676,000				

(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.

We account for the two stock option plans using APB No. 25 for directors and employees and SFAS No. 123 for consultants. There were 676,000 options granted in 2002. Directors and employees were granted 601,000 and consultants were granted 75,000. The consultant options were valued using the fair value method of SFAS No. 123 as calculated by the Black-Scholes option-pricing model. The fair value of each option grant, as opposed to its exercisable 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 14.9%, credit adjusted risk free interest rates of 8.5% and expected lives of 3.4 to 4.4 years. The resulting compensation expense relating to the consultant option grant will be included as an operating expense as the options vest.

Note 7 NOTES PAYABLE

The Company incurred the following debt:

	March 31, 2004	June 30, 2003
Note payable to a bank for the acquisition of producing gas properties located in several counties in the Sacramento Valley, California, maturing June, 2005, principal payments are $12,500 per month plus interest at the bank's prime rate plus 2%. (Rate was 6% at March 31, 2004.) The loan is collateralized by accounts receivable, other rights to payments and all inventory.	$187,500	$ 0
Less current portion	150,000	0
Long term portion	$ 37,500	$ 0

Note 8 SEGMENT INFORMATION

We operate in one industry segment within the United States, oil and gas exploration and production.

Identified assets by industry are those assets that are used in our operations in that industry. Corporate assets are principally cash, furniture, fixtures and vehicles.

We have adopted SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information." SFAS No. 131 requires the presentation of descriptive information about reportable segments which is consistent with that made available to the management of the Company to assess performance.

Our oil and gas segment derives its revenues from the sale of oil and gas and prospect generation and administrative overhead fees charged to participants in our oil and gas ventures. Corporate income is primarily derived from interest income on funds held in money market accounts.

During the nine months ended March 31, 2004 and 2003, there were no intersegment revenues. The accounting policies applied by each segment are the same as those used by us in general.

There have been no differences from the last annual report in the basis of measuring segment profit or loss. There have been no material changes in the amount of assets for any operating segment since the last annual report except for the oil and gas segment which capitalized approximately $1,033,040 for the development and acquisition of oil and gas properties.

Note 8 SEGMENT INFORMATION (CONTINUED)

Segment information consists of the following for the nine months ended March 31:

	Oil and Gas	Corporate	Consolidated
Revenues:			
2004	$ 1,257,443	$ 4,338	$ 1,261,781
2003	873,471	7,981	881,452
Income (loss) from operations:			
2004	$ 693,444	$ (473,463)	$ 219,981
2003	453,459	(484,609)	(31,150)
Identifiable assets:			
2004	$ 4,723,147	$ 790,705	$ 5,513,852
2003	3,743,528	1,527,090	5,270,618
Depreciation, depletion and valuation charged to identifiable assets:			
2004	$ 371,749	$ 13,775	$ 385,524
2003	278,787	13,258	292,045
Capital expenditures:			
2004	$ 1,033,040	$ -0-	$ 1,033,040
2003	626,385	-0-	626,385

Note 9 MAJOR CUSTOMERS

We derived in excess of 10% of our revenue from various sources (oil and gas sales) as follows:

	The Company		
	A	B	C
9 months ended:			

March 31, 2004	14%	23%	51%
March 31, 2003	-	22%	55%

Note 10 COMMITMENTS AND CONTINGENCIES

We have a proposed drilling budget for the period April through December 2004. The budget includes drilling eight wells in the Sacramento gas province of northern California and the completion of the Verona Pipeline. Our share of the estimated costs to complete this program is set forth in the following table:

Area	Wells	Drill	Complete & Equip	Total
Momentum Farmout Various Counties, CA	3	$ 57,000	$ 273,000	$ 330,000
Denverton Creek Field Solano County, CA	1	26,000	19,000	45,000
West Grimes Field Colusa County, CA	4	375,000	250,000	625,000
Verona Pipeline	--		70,000	70,000
Total Expenditure	8	$ 458,000	$ 612,000	$1,070,000

Effective January 1, 2004 through March 31, 2004, we entered into a purchase and sales agreement with a major gas purchaser to sell 500 MMBTU'S of gas per day at an average price of $6.07 per MMBTU. During the month of January, the latest date price information was available; we would have received approximately $5.66 per MMBTU with our normal pricing structure and no hedging agreements in force. There is no assurance such prices can be obtained in the future.

Note 11 INCOME TAXES

The Company has made no provision for income taxes for the nine month period ended March 31, 2004 since it utilizes net operating loss carryforwards. The Company had approximately $1,796,000 of such carryforwards at June 30, 2003.

Note 12 SUBSEQUENT EVENTS

The Ettl #1-10, located in the Grimes Gas Field, Sutter County, California, was drilled to a depth of 7,700'. Production casing was run based on promising mud log and electric log responses. A Forbes sand interval was perforated and tested at approximately 1,000 MCFPD. The shut-in tubing and casing pressures were 2,600 psig. Gas sales should commence in approximately 30 days. Aspen has a 28.75% operated working interest in this well.

Note 12 SUBSEQUENT EVENTS (CONTINUED)

The Emigh #35-6, located in the Denverton Creek Field, Solano County, California, was drilled to a depth of 11,200'. Production casing was run based on encouraging mud log and electric log responses. The well will be perforated in May 2004 to determine if commercial production can be established. Aspen has a 5.25% operated working interest in this well.

Note 13 NEW ACCOUNTING PRONOUNCEMENTS

In December 2002, the FASB approved SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure - an amendment of FASB Statement No. 123". SFAS No. 148 amends SFAS No. 123, "Accounting for Stock-Based Compensation" to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. SFAS No. 148 is effective for financial statements for fiscal years ending after December 15, 2002. The Company will continue to account for stock based compensation using the methods detailed in the stock-based compensation accounting policy.

In April 2003, the FASB approved SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities". SFAS No. 149 is not expected to apply to the Company's current or planned activities.

In June 2003, the FASB approved SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity". SFAS No. 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. This Statement is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. SFAS No. 150 is not expected to have an effect on the Company's financial position.

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

This segment should be read in conjunction with the management's discussion and analysis of financial condition and results of operations contained in our Annual Report on Form 10-KSB for the year ended June 30, 2003, which has been filed with the Securities and Exchange Commission. The management discussion and analysis and other portions 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 statements reflect our current beliefs and are based on information currently available to us. Accordingly, these statements are subject to certain risks, uncertainties, and contingencies, which could cause our actual results, performance, or achievements to differ materially from those expressed in, or implied by, such statements. These risks, uncertainties and contingencies include, without limitation, the factors set forth in our Form 10-KSB under "Item 6. Management's Discussion and Analysis of Financial Conditions or Plan of Operation - Factors that may affect future operating results." We have no obligation to update or revise any such forward-looking statements that may be made to reflect events or circumstances after the date of this Form 10-QSB.

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 38 gas wells and have a non-operated interest in 16 additional gas wells.

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.

We will typically review 20 to 25 prospects for every well we participate in, using 3-D seismic and well control geology to evaluate each prospect. Our goal is to identify low to moderate risk wells with good gas reserve potential.

Where possible, we attempt to be the operator of each property we invest in. 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 33% of our selling, general and administrative expenses.

Outlook and Trends

We expect our natural gas production volumes to range between 290,000 to 320,000 MMBTU for the fiscal year ending June 30, 2004. We also anticipate that the average price for our product will be in the range of $4.70 to $5.20 per MMBTU for the fiscal year ended June 30, 2004.

Over the past five years we have been able to replace our produced reserves and increase our yearly natural gas production. We have also benefited from a general increase in natural gas prices over the past two years, from a low of $2.78 per MMBTU average during the first quarter of fiscal 2003 to $5.28 per MMBTU for the quarter ended March 31, 2004.

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 ratio over the past three years has been 80%. 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 as well as anyone in the industry.

Commodity prices are impacted by many factors that are outside of our control. Historically, commodity prices have been volatile and we expect them to remain volatile. Commodity prices are affected by changes in market demands, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, 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.

In the past, Aspen has borrowed funds from an affiliate in 1997 and withdrew funds from a life insurance policy in 1997 and 2000 to drill, develop and produce our reserves. We are exposed to interest rate risk to the extent we have borrowed funds. During December 2003, we borrowed $225,000 from a bank for a modest acquisition. We currently pay 2% over the bank's prime rate for that facility. At March 31, 2004, the effective interest rate was 6%.

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

Cash of $468,200 and $840,600 was provided by our operations for the nine months ended March 31, 2004 and 2003. Even though the 2003 period generated a loss of $(31,150), we were able to generate a larger positive cash flow from operations during the first nine months of fiscal 2003 as compared to the 2004 period (when we generated net income of $219,981) because of:

Lower depreciation, depletion and amortization expenses ($292,045 in 2003 as compared to $385,524 in 2004);

A $77,162 decrease in accounts receivable during 2003 (which provided cash) compared to an increase in accounts receivable during 2004 of $38,445; and

A $494,233 increase in accounts payable and accrued expenses in 2003 (which conserved cash) compared to an $111,494 reduction in accounts payable and accrued expenses in 2004 (which required cash payments).

Investing activities used cash to increase capitalized oil and gas costs of $1,033,000 and $626,400 in the nine months ended March 31, 2004 and 2003. Cash in the current nine month period ended 2004 was used for lease acquisition and seismic work ($712,600), intangible drilling and well workovers ($284,000), and the purchase of oil and gas well equipment ($36,400). These expenditures were offset by the sale of interests in wells to be drilled charged to third party investors.

We have a proposed drilling, completion and construction budget for the period April through December 2004. The budget includes drilling eight wells in the Sacramento gas province of northern California and the completion of the Verona Pipeline. Our share of the estimated costs to complete this program over the next eight months is set forth in the following table:

Area	Wells	Drill	Complete & Equip	Total
Momentum Farmout Various Counties, CA	3	$ 57,000	$ 273,000	$ 330,000
Denverton Creek Field Solano County, CA	1	26,000	19,000	45,000
West Grimes Field Colusa County, CA	4	375,000	250,000	625,000
Verona Pipeline	--		70,000	70,000
Total Expenditure	8	$ 458,000	$ 612,000	$1,070,000

Our working capital (current assets less current liabilities) at March 31, 2004, was $87,445. We anticipate that our working capital and anticipated cash flow from operations and future successful drilling will be sufficient to pay our current liabilities as long as our gas production continues to provide us with sufficient cash flow. As discussed below, 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.

Our capital requirements can fluctuate over a twelve month period because our drilling program is usually carried out in California's dry season, from late April until November, after which wet weather either precludes further activity or makes it cost prohibitive.

We believe that internally generated funds will be sufficient to finance our drilling and operating expenses for the next twelve months. However, during December 2003, we borrowed $225,000 from a bank in California and used the proceeds to acquire various working interests in producing gas wells located in several counties in the Sacramento Valley, California. 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 any future completion and pipeline costs.

Results of Operations

March 31, 2004 Compared to March 31, 2003

For the nine months ended March 31, 2004 our operations continued to be focused on the production of oil and gas, and the investigation for possible acquisition of producing oil and gas properties in California. During the 2004 period our revenues increased by more than $352,000 as compared to the comparable period of our 2003 fiscal year because of:

Increased production (224,400 MMBTU sold as compared to 187,400 MMBTU sold during the first nine months of our 2003 fiscal year);

Increased price received for our production (an average of $4.88 per MMBTU during the first nine months of our 2004 fiscal year as compared to $3.23 per MMBTU received during that period in 2003); and

Increased management fees received ($150,634 during 2004 as compared to $119,118 during 2003) because we were operators of more wells during 2004 (38 wells compared to 33 wells in 2003).

When comparing the three month periods ended March 31, 2004 and 2003, our revenues increased by more than $100,000 and net income increased by $48,000, or 167%, from $28,750 to $76,760 due to:

Increased production (71,900 MMBTU sold compared to 57,900 MMBTU sold during the previous three months 2003 fiscal quarter) a 24% improvement;

Decreased price received for our production (an average of $5.28 per MMBTU during the quarter ended March 31, 2004 as compared to $5.47 per MMBTU received during that period in 2003) a 3.5% decline; and

Increased management fees received ($38,600 as compared to $22,300 during 2003) a 73% increase.

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The following table sets forth certain items from our Condensed Consolidated Statements of Operations as expressed as a percentage of total revenues, shown by quarter for the nine months of fiscal 2004 and 2003:

	For the Quarter Ended			For
	3/31/2004	12/31/2003	9/30/2003	3/31/2003
Total revenues	100.0%	100.0%	100.0%	100.0%
Oil & gas production costs	19.5	14.6	10.1	19.2
Income from operations	80.5	85.4	89.9	80.8
Costs and expenses				
Depreciation and depletion	29.0	30.1	32.9	32.2
Selling, general and administrative	33.4	33.6	44.1	40.1
Interest expense	.7	.0	.0	.0
Total costs and expenses	63.1	63.7	77.0	72.3

Income before income taxes	17.4	21.7	12.9	8.5
Provision for income taxes	.0	.0	.0	.0
Net income (loss)	17.4	21.7	12.9	8.5

To facilitate discussion of our operating results for the nine months ended March 31, 2004 and 2003, 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)	
	2004	2003	Amount	Percentage
Revenues:				
Oil and gas sales	$1,106,809	$ 754,353	$ 352,456	46.7%
Management fees	150,634	119,118	31,516	26.5
Interest and other	4,338	7,981	(3,643)	(45.6)
Total revenues	1,261,781	881,452	380,329	43.1
Cost and expenses:				
Oil and gas production	188,301	141,225	47,076	33.3
Depreciation and depletion	385,524	292,045	93,479	32.0
Selling, general and administrative	464,026	478,853	(14,827)	(3.1)
Interest expense	3,949	479	3,470	724.4
Total costs and expenses	1,041,800	912,602	129,198	14.2%
Net income (loss)	$ 219,981	$ (31,150)		

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Central to the issue of success of the nine months operations ended March 31, 2004 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/MMBTU
2004			
1st Quarter	$ 341,926	72,600	$ 4.75
2nd Quarter	362,942	79,900	4.64
3rd Quarter	401,941	71,900	5.28
Year to date	1,106,809	224,400	4.88
2003			

1st Quarter	198,431	65,800	2.78
2nd Quarter	241,700	63,700	3.76
3rd Quarter	314,222	57,900	5.47
Year to date	754,353	187,400	3.23
Year to date change			
Amount	$ 352,456	37,000	$ 1.65
Percentage	46.7%	19.7%	51%

(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, volumes sold and price received for our product have shown a steady improvement over the past nine months of fiscal 2004 and the twelve months of fiscal 2003. As the table above notes, revenue has increased approximately 47% when comparing the two nine month periods ended March 31, 2004 and 2003. Volumes sold increased approximately 20%, while the price received for our product increased 51%.

Total revenue increased $380,300, or 43% when comparing the two periods, while operating and production costs increased $47,100, or 33%.

A significant ratio presented is the percentage of management fees charged to operated wells versus our general and administrative costs. This coverage of general and administrative costs improved from approximately 25% for the nine months ended March 31, 2003 to approximately 32% at March 31, 2004.

When comparing general and administrative expense for 2004 and 2003, costs declined slightly by $14,800, or 3.1%.

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Results of operations and net income are presented in the following table:

Quarterly Financial Information (unaudited)

2004	Total Revenues	(1) Operating Income	Net Income (loss)	Net Income (loss) Per Share Basic	Net Income (loss) Per Share Diluted
1st Quarter	$ 388,337	$ 348,739	$ 50,197	.014	.014
2nd Quarter	433,317	365,761	93,022	.016	.016
3rd Quarter	440,127	354,642	76,762	.010	.010
Total	1,261,781	1,069,142	219,981	0.04	0.04
2003					
1st Quarter	264,896	232,246	(44,238)	(.01)	(.01)
2nd Quarter	279,080	237,155	(15,660)	--	--
3rd Quarter	337,476	271,845	28,748	--	--
Total	$ 881,452	$ 741,246	$ (31,150)	--	--

(1) Operating income is oil and gas sales plus management fees less direct operating costs.

As can be seen in the table, revenues and operating income have improved in every quarter when comparing the nine month periods ended March 31, 2004 and 2003. We believe this is due to the steady increase in production volumes sold in each subsequent quarter and the fact that we have enjoyed an appreciating price received for our product. Operating income has increased because production costs have increased at a lesser rate than production and prices.

Contractual Obligations:

We had six contractual obligations as of March 31, 2004. The following table lists our significant liabilities at March 31, 2004:

	Payments Due By Period				
Contractual Obligations	Less than 1 year	2-3 years	4-5 years	After 5 years	Total
Employment Obligations	$207,483	$300,800	$ 160,800	-0-	$669,083
Bank Loans	150,000	37,500	-0-	-0-	187,500
Operating Leases	20,310	3,710	-0-	-0-	24,020
Total contractual cash obligations	$377,793	$342,010	$ 160,800	$ -0-	$880,603

We maintain office space in Denver, Colorado, our principal office, Castle Rock, Colorado 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. The Bakersfield, California office has 546 square feet and a monthly rental fee of $730 to $770 over the term of the lease. The three year lease expires February 8, 2006. Rent expense for the nine months ended March 31, 2004 and 2003 was $18,337 and $22,620, respectively.

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Critical Accounting Policies and Estimates:

We believe the following critical accounting policies affect our most significant judgments and estimates used in the preparation of our Condensed Consolidated Financial Statements.

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.

Property, Equipment, Depreciation and Depletion:

We follow the full-cost method of accounting for oil and gas properties. Under this method, all productive and nonproductive costs incurred in connection with the exploration for and development of oil and gas reserves are capitalized. Such capitalized costs include lease acquisition, geological and geophysical work, delay rentals, drilling, completing and equipping oil and gas wells, including salaries, benefits and other internal salary related costs directly attributable to these activities. Costs associated with production and general corporate activities are expensed in the period incurred. Interest costs related to unproved properties and properties under development are also capitalized to oil and gas properties. If the net investment in oil and gas properties exceeds an amount equal to the sum of (1) the standardized measure of discounted future net cash flows from proved reserves, and (2) the lower of cost or fair market value of properties in process of development and unexplored acreage, the excess is charged to expense as additional depletion. Normal dispositions of oil and gas properties are accounted for as adjustments of capitalized costs, with no gain or loss recognized.

We apply SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." Under SFAS No. 144, long-lived assets and certain intangibles are reported at the lower of the carrying amount or their estimated recoverable amounts. Long-lived assets subject to the requirements of SFAS No. 144 are evaluated for possible impairment through review of undiscounted expected future cash flows. If the sum of undiscounted expected future cash flows is less than the carrying amount of the asset or if changes in facts and circumstances indicate, an impairment loss is recognized.

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 6%. 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.

Item 3. CONTROLS AND PROCEDURES

As required by Rule 13a-15 under the Securities Exchange Act of 1934, as of the filing date of this report, we carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures. This evaluation was carried out under the supervision and with the participation of our principal executive officer (who is also our principal financial officer), who concluded that our disclosure controls and procedures are effective. There have been no significant changes in our internal controls or in other factors, which could significantly affect internal controls subsequent to the date we carried out our evaluation.

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed in our reports filed or submitted under the Securities Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the Securities and Exchange Commission's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed in our reports filed under the Exchange Act is accumulated and communicated to management, including our principal executive officer and our principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

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. Changes in Securities and Small Business Issuer Purchases of Equity Securities.

None.

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 and Reports on Form 8-K.

(a) Exhibits

31. Rule 13a-14(a) Certification
32. Section 1350 Certification

(b) Reports on Form 8-K

None.

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

/s/ Robert A. Cohan

By: Robert A. Cohan,
Chief Executive Officer,
Principal Financial Officer

May 12, 2004