ASPEN EXPLORATION CORP
Form 10QSB
February 11, 2004

FORM 10-Q-SB

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 December 31, 2003

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

Class	Outstanding at February 11, 2004
Common stock, $.005 par value	5,863,828

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

Part One. FINANCIAL INFORMATION

Item 1. Financial Statements

ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

ASSETS

	December 31, 2003 (Unaudited)	June 30, 2003 (Audited)
Current Assets:		
Cash and cash equivalents, including $247,570 and $516,365 of invested cash at December 31, 2003 and June 30, 2003 respectively	$ 916,031	$ 776,566
Precious metals	18,823	18,823
Accounts receivable	318,450	269,259
Receivable, related party	11,314	6,302
Prepaid expenses	11,370	22,181
Total current assets	1,275,988	1,093,131
Investment in oil and gas properties, at cost (full cost method of accounting)	7,642,168	6,723,579
Less accumulated depletion and valuation allowance	(2,924,469)	(2,674,469)
	4,717,699	4,049,110
Property and equipment, at cost:		
Furniture, fixtures and vehicles	112,562	112,562
Less accumulated depreciation	(73,378)	(64,178)
	39,184	48,384
TOTAL ASSETS	$ 6,032,871	$ 5,190,625

(Statement Continues)
See notes to Consolidated Financial Statements

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ASPEN EXPLORATION CORPORATION AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS (Continued)

LIABILITIES AND STOCKHOLDERS' EQUITY

	December 31, 2003 (Unaudited)	June 30, 2003 (Audited)
Current liabilities:		
Accounts payable and accrued expenses	$ 1,043,005	$ 581,895
Accounts payable - related party	12,188	17,685
Advances from joint interest owners	141,995	150,821

Notes payable - current	150,000	0
Total current liabilities	1,347,188	750,401
Asset retirement obligation	45,081	17,841
Deferred income taxes	131,350	131,350
Notes payable - long term	75,000	0
Total long term liabilities	251,431	149,191
Total liabilities	1,598,619	899,592
Stockholders' equity:		
Common stock, $.005 par value: Authorized: 50,000,000 shares Issued: at December 31, 2003 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	(1,613,681)	(1,756,900)
Deferred compensation	(7,184)	(7,184)
Total stockholders' equity	4,434,252	4,291,033
Total liabilities and stockholders' equity	$ 6,032,871	$ 5,190,625

See Notes to Consolidated Financial Statements

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

	Three Months Ended December 31,		Six Months Ended December 31,	
	2003	2002	2003	2002
Revenues:				
Oil and gas	$ 362,942	$ 241,700	$ 704,868	$ 440,1
Management fees	66,106	34,066	112,021	96,7
Interest and other, net	4,269	3,314	4,765	7,0
Total Revenues	433,317	279,080	821,654	543,9
Costs and expenses:				
Oil and gas production	63,287	38,611	102,389	76,5
Depreciation, depletion and amortization	130,349	97,969	257,949	183,3
Selling, general and administrative	145,788	157,681	317,226	343,4
Interest expense	871	479	871	4

Total Costs and Expenses	340,295	294,740	678,435	603,8
Income (loss) before taxes	93,022	(15,660)	143,219	(59,8
Provision for income taxes	0	0	0	
Net income (loss)	$ 93,022	$ (15,660)	$ 143,219	$ (59,8
Basic income (loss) per common share	$ .01	$ (--)	$ .02	$ (.
Diluted income (loss) per common share ...	$ .01	$ (--)	$ .02	$ (.
Basic weighted average number of common shares outstanding	5,863,828	5,863,828	5,863,828	5,863,8
Diluted weighted average number of common shares outstanding	6,144,999	5,863,828	6,144,999	5,863,8

The accompanying notes are an integral part of these statements.

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

	Six months ended December 31,	
	2003	2002
Cash flows from operating activities:		
Net income (loss)	$ 143,219	$ (59,898)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	257,949	183,390
Changes in assets and liabilities:		
Decrease (increase) in receivable	(54,413)	89,373
Decrease in prepaid expense	10,811	5,026
Increase in accounts payable and accrued expense	446,787	205,792
Net cash provided by operating activities	804,353	423,683
Cash flows from investing activities:		
Additions to oil and gas properties	(889,888)	(396,504)
Proceeds - sale of oil and gas properties	--	69,422
Proceeds - sale of idle equipment	--	1,155

Net cash (used) by investing activities	(889,888)	(325,927)
Cash flow from financing activities:		
Proceeds from notes payable	225,000	--
Net increase in cash and cash equivalents	139,465	97,756
Cash and cash equivalents, beginning of year	776,566	916,001
Cash and cash equivalents, end of year	$ 916,031	$ 1,013,757
Other information:		
Interest paid	$ 871	$ 479
Non-cash investing activities		
Asset retirement obligation	$ 29,007	$ 0

The accompanying notes are an integral part of these statements.

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ASPEN EXPLORATION CORPORATION

Notes to Consolidated Financial Statements
(Unaudited)

December 31, 2003

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 the full 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.

We did not change or reclassify contractual mineral rights included in oil and gas properties on the balance sheet upon adoption of SFAS No. 141. We believe its current accounting of such mineral rights as part of oil and gas properties is appropriate under the full cost method of accounting. However, if the accounting for mineral rights held by lease or contract is ultimately changed so that costs associated with mineral rights not held under fee title and pursuant to the guidelines of SFAS No. 141 are required to be classified as long term intangible assets, then the reclassified amount as of December 31, 2003 and June 30, 2003 (the end of our last completed fiscal year) would be approximately $1.6 million. Management does not believe that the ultimate outcome of this issue will have a significant impact on our cash flows, results of operations or financial position.

Note 3   RECEIVABLE - RELATED PARTIES

The receivable from related parties constitutes amounts due from officers 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 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 December 31, 2003 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 December 31, 2003	$ 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 $143,219 for the six months ended December 31, 2003 and a net loss of $59,898 for the six months ended December 31, 2002. Because of the net loss for the six months ended December 31, 2002, 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.

	December 31, 2003		
	Net Income	Shares	Per Share Amount
Basic earnings per share:			
Net income and share amounts	$ 143,219	5,863,828	$ .02
Dilutive securities: stock options		776,000	
Repurchased shares		(494,829)	
Diluted earnings per share:			
Net income and assumed share conversion	$ 143,219	6,144,999	$ .02

Note 6 NOTES PAYABLE

The Company incurred the following debt:

	December 31, 2003	June 30, 2003
Note payable to a bank for the acquisition of producing gas properties located in several counties in the Sacramento Valley, California, principal payments are $12,500 per month plus interest at the bank's prime rate plus 2%. (Rate was 6% at December 31, 2003.) The loan is collateralized by accounts receivable, other rights to payments and all inventory	$225,000	$ 0
Less current portion	150,000	0
Long term portion	$ 75,000	$ 0

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Note 7 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 six months ended December 31, 2003 and 2002 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 $889,888 for the development and acquisition of oil and gas properties.

Note 7 SEGMENT INFORMATION (CONTINUED)

Segment information consists of the following for the six months ended December 31:

		Oil and Gas	Corporate	Consolidated
Revenues:				
	2003	$ 816,889	$ 4,765	$ 821,654
	2002	536,926	7,050	543,976
Income (loss) from operations:				
	2003	$ 465,751	$ (322,532)	$ 143,219
	2002	285,850	(345,748)	(59,898)
Identifiable assets:				
	2003	$ 4,849,966	$ 1,182,905	$ 6,032,871
	2002	3,605,672	1,344,382	4,950,054
Depreciation, depletion and valuation charged to identifiable assets:				
	2003	$ (248,749)	$ (9,200)	$ (257,949)
	2002	(174,551)	(8,838)	(183,389)
Capital expenditures:				
	2003	$ 889,888	$ -0-	$ 889,888
	2002	396,504	-0-	396,504

Note 8 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
Year ended:			
December 31, 2003	26%	54%	11%
December 31, 2002	24%	53%	-

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Note 9 COMMITMENTS AND CONTINGENCIES

At December 31, 2003, the Company was committed to the following drilling and development projects in California:

Project	Aspen Cost
6 well farmout	$ 0
Verona Pipeline	70,000
Total	$ 70,000

We are committed to a 6 well farmout and drilling program to be completed during fiscal 2004 and 2005. Our 30% working interest share of the costs of this project are estimated to be $-0- because of prospect fees charged to the other working interest owners.

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 10 INCOME TAXES

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

Note 11 SUBSEQUENT EVENTS

Aspen and partners have recently completed the shooting of a 10.5 square mile 3-D seismic program located over its acreage in the West Grimes Field, Colusa County, California, approximately 100 miles northeast of Sacramento. The data has been processed and is currently being evaluated by one of Aspen's consulting geophysicists.

Note 12 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.

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Note 12 NEW ACCOUNTING PRONOUNCEMENTS (CONTINUED)

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 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. This management's 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.

Liquidity and Capital Resources

December 31, 2003 as compared to June 30, 2003

At December 31, 2003 current assets were $1,275,988 and current liabilities were $1,347,188 and we had negative working capital of $71,200 compared to current assets of $1,093,131 at June 30, 2003 and current liabilities of $750,401 at June 30, 2003, resulting in working capital at June 30, 2003 of $342,730. Our working capital decreased $271,530 from June 30, 2003 to December 31, 2003 for several reasons.

Our current assets increased $182,857 due, in part, to an increase in cash and cash equivalents of $139,465 from $776,566 to $916,031. Much of the increase in cash was due to an increase in revenue received by us in December and disbursed to other revenue interest owners in January 2004. We also received $56,000 in prospect fees from other working interest owners for the Mengali-Durst #22-1 and the Sac Outing #31-3 wells, which were drilled in October 2003. Accounts receivable trade increased by $54,203 because of the completion of various drilling projects, which were in process at year end. Prepaid expenses decreased $10,811, or 49%, reflecting a reduction in prepaid taxes and the expensing of engineering fees at the end of the six month period.

Our current liabilities increased $596,787 to $1,347,188 at December 31, 2003 from $750,401 at June 30, 2003. This increase was due to a number of factors including the receipt of revenue due to other revenue owners of approximately $490,000 and the current portion of notes payable of $150,000 incurred in December, the proceeds of which were used to acquire producing gas wells located in northern California. Other than noted, current liabilities decreased $43,213.

We anticipate that our current assets 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.

Drilling success during the past year added to our cash flow from operations. These successes have been offset by the decline in production rates from older wells and the sale of our producing oil wells in Kern County in 2002. The average price received for oil and gas for the quarter ended December 31, 2003 was $23.93 per barrel and $4.67 per MMBTU of gas compared to $25.39 per barrel and $3.36 per MMBTU of gas at December 31, 2002, a decrease of 6% and increase of 40%, respectively.

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. In October 2003, we drilled and abandoned two wells at a cost to us of $84,000.

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.

Results of Operations

December 31, 2003 Compared to December 31, 2002

For the six months ended December 31, 2003 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.

Oil and gas revenues, which include income from management fees, for the six months ended December 31, 2003 increased approximately $279,963 from $536,926 to $816,889, a 52% increase. This increase reflects an increase in the prices received for the sale of gas which was partially offset by a decrease in production in the Denverton Creek and Malton Black Butte fields as well as the Kern County oil properties, which were sold on September 1, 2002. Our share of sales of gas for the six month period ended December 31, 2003 was approximately 151,000 MMBTU of gas. The average price received for the six months ended December 31, 2003 was $4.67 per MMBTU for gas. This is an increase in natural gas production of 9% when compared to the approximately 138,600 MMBTU of gas production achieved during the six months of the 2002 fiscal year. Another factor resulting in increased revenues during the six months of fiscal 2003 was an increase in the prices received for our gas production when compared to the price of $3.36 received for gas during the first six months of fiscal 2002.

Oil and gas production costs increased $25,864 from $76,525 to $102,389. The increase in costs reflects the addition of new wells during normal operations during the past twelve months, and the addition of compression costs associated with older gas wells with declining pressures.

Depletion, depreciation and amortization increased approximately $74,600 or 41% from the previous six months, which is our best estimate of what the full year cost will be.

Selling, general and administrative expense decreased approximately 8% from $343,481 to $317,226 for the six months ended December 31, 2003. This decrease is primarily due to a reduction of salary and benefits to officers.

As a result of our operations, we ended the six month period with net income of $143,219 compared to net loss of $59,898 for the corresponding six months a year earlier. This improvement is due primarily to an increase in the price received for our gas and an increase in gas production volumes, from 138,600 MMBTU to 151,000 MMBTU, a 9% increase. The net income was further enhanced by the reduction of general and administrative costs as previously discussed. Effective September 1, 2002, we sold our remaining interest in producing oil wells located in Kern County, California for approximately $70,000 net to our interest. As of September 1, 2002, we are only producing and selling natural gas with small amounts of associated condensate sales.

Interest and other income decreased approximately $2,285 to $4,765 and were primarily due to a decline in interest rates.

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Contractual Obligations:

We had six contractual obligations as of December 31, 2003. The following table lists our significant liabilities at December 31, 2003:

	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	$ 20,100	$689,183
Bank Loans	150,000	75,000	0	0	225,000
Operating Leases	24,092	5,960	0	0	30,052
Total contractual cash obligations	$381,575	$381,760	$160,800	$ 20,100	$944,235

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 six months ended December 31, 2003 and 2002 was $11,946 and $11,596, respectively.

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 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.

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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 and Depreciation:

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 Use of Proceeds.

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

During the period covered by this report and subsequently, we filed one report on Form 8-K as follows:

Date: 12/15/2003 Item reported: Item 12, "Results of Operations and Financial Condition.
No financial statements were filed with this Form 8-K.

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

February 11, 2004