ASPEN EXPLORATION CORP
Form 10QSB
November 10, 2005

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 September 30, 2005

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 November 10, 2005
Common stock, $.005 par value	6,758,308

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

	September 30, 2005
Current Assets:	
Cash and cash equivalents, including $3,410,281 and $2,812,971 of invested cashat September 30, 2005 and June 30, 2005 respectively	$ 3,658,625
Accounts & trade receivables	791,211
Accounts receivable, related party	36,845
Prepaid expenses...	13,088
Precious metals	18,823
Total current assets	4,518,592
Investment in oil and gas properties, at cost (full cost method of accounting)	10,799,378
Less accumulated depletion and valuation allowance	(4,837,090)
	5,962,288
Property and equipment, at cost:	
Furniture, fixtures and vehicles	114,076
Less accumulated depreciation	(39,637)
	74,439
TOTAL ASSETS	$ 10,555,319

(Statement Continues)
See notes to Consolidated Financial Statements

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

LIABILITIES AND STOCKHOLDERS' EQUITY

	September 30, 2005
Current liabilities:	
Accounts payable and accrued expenses	$ 977,105
Accounts payable - related party (Note 6)	73,767
Advances from joint interest owners	1,035,221
Asset retirement obligation (Note 3)	13,826
Total current liabilities	2,099,919
Asset retirement obligation, net of current portion (Note 3)	108,384
Deferred income taxes (Note 9)	1,195,883
Total long term liabilities	1,304,267
Total liabilities	3,404,186
Stockholders' equity: (Notes 1 and 5):	
Common stock, $.005 par value: Authorized: 50,000,000 shares Issued and outstanding: At September 30, 2005, 6,758,308 shares and June 30, 2005, 6,733,308	33,791
Capital in excess of par value	6,742,446
Accumulated retained earnings (deficit)	392,133
Deferred compensation	(17,237)
Total stockholders' equity	7,151,133
Total liabilities and stockholders' equity	$ 10,555,319

See Notes to Consolidated Financial Statements

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

	Three Mont Septemb
	2005
Revenues:	
Oil and gas	$1,062,543
Management fees	120,924
Total Revenues	1,183,467
Costs and expenses:	

Oil and gas production	71,019
Depreciation, depletion and amortization	254,336
Selling, general and administrative	227,116
Total Costs and Expenses	552,471
Operating income	630,996
Other income (expense)	
Interest and other, net	10,701
Interest (expense)	0
Income before taxes	641,697
Provision for income taxes	180,395
Net income	$ 461,302
Basic income per common share	$ .07
Diluted income per common share	$ .06
Basic weighted average number of common shares outstanding	6,745,808
Diluted weighted average number of common shares outstanding	7,163,243

The accompanying notes are an integral part of these statements.

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

	Three months e 2005
Cash flows from operating activities:	
Net income	$ 461,302
Adjustments to reconcile net income to net cash provided used by operating activities:	
Depreciation, depletion and amortization	254,336
Stock issued for interest expense	--
Deferred income tax provision	180,395
Changes in assets and liabilities:	
(Increase) in receivable	(200,336)
Decrease in prepaid expense	2,334
Increase (decrease) in accounts payable and accrued expense	617,193
Net cash provided by operating activities	1,315,224

Cash flows from investing activities:	
Additions to oil and gas properties	(1,102,995)
Purchase of producing properties	--
Equipment inventory sales	2,000
Net cash (used) by investing activities	(1,100,995)
Cash flow from financing activities:	
Common stock options exercised	14,250
Payment of notes payable	--
	14,250
Net increase (decrease) in cash and cash equivalents	228,479
Cash and cash equivalents, beginning of year	3,430,146
Cash and cash equivalents, end of year	$ 3,658,625
Other information	
Interest paid	$ -0-
Non-cash transactions additions to asset retirement obligation	$ 26,000

The accompanying notes are an integral part of these statements.

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ASPEN EXPLORATION CORPORATION

Notes to Condensed Consolidated Financial Statements
(Unaudited)

September 30, 2005

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, 2005.

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, 2005.

Note 2 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 and provide for the same terms as other unaffiliated joint owners and are repaid in a normal business cycle.

Note 3 ASSET RETIREMENT OBLIGATION

We have adopted the provisions of Statement of Financial Accounting Standards ("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

Note 3 ASSET RETIREMENT OBLIGATION (CONTINUED)

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 September 30, 2005 is as follows:

Asset retirement obligations as of June 30, 2005	$ 96,210
ARO additions	26,000
Liabilities settled	-0-
Accretion expense	-0-*
Revision of estimate	-0-
Asset retirement obligation as of September 30, 2005	$ 122,210

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* Accretion not material

Note 4 EARNINGS PER SHARE

We follow 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.

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 $461,302 for the three months ended September 30, 2005 and $221,618 for the three months ended September 30, 2004.

	Three Months Ended September 30, 2005			Sept	
	Net Income	Shares	Per Share Amount	Net Income	Shares
Basic earnings per share:					
Net income and share amounts	$ 461,302	6,745,808	$ .07	$ 221,618	6,235,
Dilutive securities: stock options	--	527,000	--		392,
Repurchased shares	--	(109,565)	--		(205,
Diluted earnings per share:					
Net income and assumed share conversion	$ 461,302	7,163,243	$ .06	$ 221,618	6,421,

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Note 5 STOCKHOLDERS' EQUITY

Stock Options

On August 15, 2005, a consultant exercised options for 25,000 shares of our common stock granted March 14, 2002 at an average price of $0.57 per share. The consultant paid us $14,250 to exercise his options on the 25,000 shares.

As of September 30, 2005, we had an aggregate of 527,000 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.

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

	Number of Shares	Weighted Average Price of Shares U
Outstanding balance June 30, 2005	552,000	$1.559
Granted	-0-	--
Exercised	(25,000)	.57
Forfeited or expensed	-0-	--
Outstanding balance September 30, 2005	527,000	$1.606

The following table summarizes information concerning outstanding and exercisable options as of September 30, 2005:

		Outstanding		Exercisable	
Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life In Years	Weighted Average Exercisable Price	Number Exercisable	Weighted Average Exercise Price
$ .57	117,000	08/15/2006(1)	$ .57	-0-	$ .57
.57	150,000	08/15/2007(1)	.57	-0-	.57
2.67	260,000	01/01/2007(1)	2.67	-0-	2.67
	527,000				

(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 stock options using APB No. 25 for directors and employees and SFAS No. 123 for consultants.

There were 260,000 options granted in 2005. Directors and employees were granted 235,000 and consultants were granted 25,000. 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

Note 5 STOCKHOLDERS' EQUITY (CONTINUED)

159.54%, risk free interest rates of 3.92% and expected lives of 4.5 years. The resulting compensation expense relating to the option grant to directors and employees of $549,821 and consultant of $58,492 will be included as an operating expense ratably over the vesting period. The options vest one-third January 2006, 2007 and 2008.

Note 6 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	D
Quarter ended:				
September 30, 2005	46%	40%	*	11%
September 30, 2004	26%	55%	11%	*

* Less than 10%.

Note 7 INCOME TAXES

We have recorded a deferred income tax liability of $1,195,883 as of September 30, 2005. During the first quarter of 2005, we used no net operating loss carryforwards leaving approximately $164,000 in available federal net operating loss carryforwards as of September 30, 2005.

The deferred tax consequences of temporary differences in reporting items for financial statement and income tax purposes are recognized, if appropriate. Realization of future tax benefits related to the deferred tax assets is dependent on many factors, including our ability to generate taxable income within the net operating loss carryforward period. We have considered these factors in reaching our conclusion as to the valuation allowance for financial reporting purposes. Primarily, our proved oil and gas reserves substantially exceed our expected future costs and hence, we believe it more likely than not that the benefit will be realized.

Note 7 INCOME TAXES (CONTINUED)

At September 30, the income tax effect of temporary differences comprising the deferred tax assets and deferred tax liabilities on the accompanying balance sheet is the result of the following:

	2005
Deferred tax assets:	
Federal tax loss carryforwards	$ 149,133
Asset retirement obligation	10,999
	160,132
Deferred tax (liabilities):	
Property, plant and equipment	277
Oil and gas properties	(1,356,292)
	(1,356,015)
	$(1,195,883)

A reconciliation between the statutory federal income tax rate (34%) and the effective rate of income tax expense for the two years ended September 30 is as follows:

	2005
Statutory federal income tax rate	34%
Less: Net operating losses and Future deductions	(15)%
Net federal income tax rate	19%
Statutory state income tax rate, net of federal benefit	9%
Effective rate	28%

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Note 7 INCOME TAXES (CONTINUED)

The provision for income taxes consists of the following components:

	2005	2004
Current tax expense, state	$ --	$ --
Deferred tax expense	180,395	168,163
Total income tax provision	$180,395	$168,163

We have available federal net operating loss carryforwards of approximately $164,000 (net operating losses expire beginning June 30, 2023 through the year ending June 30, 2026).

Note 8 DRILLING COMMITMENTS AND CONTINGENCIES

We have a proposed drilling budget for the period October through December 2005. The budget includes drilling four wells in the Sacramento gas province of northern California. Our share of the estimated costs to complete this program is set forth in the following table:

Area	Wells	Drilling Costs	Comple Equippin
Denverton Creek Field, Solano County, CA	1	$170,000	
West Grimes Field Colusa County, CA	1	139,000	
Buckeye, Colusa County, CA	1	165,000	
Winters, Yolo County, CA	1	85,000	
Total Expenditure	4	$559,000	

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Note 9 SUBSEQUENT EVENTS

The Kalfsbeek #1-13 well located in the Buckeye Gas Field, Colusa County, California, was drilled to a depth of 8,800 feet and encountered approximately 90 feet of potential gas pay in several intervals in the Forbes formation. Production casing was run based on favorable mud log and electric log responses. Several of these Forbes intervals were perforated and tested gas at a stabilized rate of 2,909 MCFPD with a flowing tubing pressure of 2,005 psig and a flowing casing pressure of 2,080 psig. The shut in tubing and casing pressures were 3,250 psig. Aspen has a 30.625% operated working interest in this well.

The WGU #15-10 well located in the West Grimes Gas Field, Colusa County, California, was directionally drilled to a depth of 8,520 feet (7,975 feet TVD) and encountered approximately 100 feet of potential gas pay in several intervals in the Forbes formation. Production casing was run based on favorable mud log and electric log responses. Aspen has a 21% operated working interest in this well.

The Street #1-3 well located in the Dry Slough Gas Field, Yolo County, California, was directionally drilled to a depth of 6,450 feet (5,563 feet TVD) and encountered approximately 45 feet of potential gas pay in several intervals in the Starkey and Winters formations. Production casing was run based on favorable mud log and electric log responses. The well will be completed in the near future. Aspen has a 21.875% operated working interest in this well.

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, 2005, 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 51 gas wells and have a non-operated interest in 15 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. 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 53% of our selling, general and administrative expenses.

Outlook and Trends

We expect our natural gas production to increase substantially during fiscal 2006 due to recent drilling successes. Total production for the year will depend on the number of wells successfully completed, the date they are put on line, their initial rate of production, and their production decline rates. We also anticipate that the gas price for our product will be in the range of $7.00 to $13.00 per MMBTU for the fiscal year ended June 30, 2006 as compared to the gas price of $6.20 during our 2005 fiscal year.

Over the past five years we have been able to replace the majority of 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 $7.26 per MMBTU for the quarter ended September 30, 2005.

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 five years has been 88%. 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. During the period November 1, 2005 through March 31, 2006, we are contractually obligated to deliver 3,750 MMBTU per day to two of our natural gas purchasers as follows:

1,000 MMBTU/Day @ $8.43 per MMBTU
1,000 MMBTU/Day @ $8.40 per MMBTU
500 MMBTU/Day @ $9.49 per MMBTU
500 MMBTU/Day @ $9.48 per MMBTU

750 MMBTU/Day @ $11.02 per MMBTU

The average price received during the first quarter of fiscal 2006 for our natural gas was approximately $7.21 per MMBTU.

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, completion and production of prospects, the acquisition of producing properties, working capital, servicing debt and the payment of income taxes.

Cash of $1,315,224 and $344,477 was provided by our operations for the three months ended September 30, 2005 and 2004. The 2005 period generated net income of $461,302, and we were able to generate increased positive cash flow from operations during the first three months of fiscal 2005 as compared to the 2004 period (when we generated net income of $221,618) because of:

An increase in oil and gas sales (52%) due to increased volumes sold (13%) and the price received for our gas (37%); and

An increase in accounts payable and accrued expenses of $617,193 in 2005 (which conserved cash) compared to a decrease in accounts payable and accrued expenses of $143,242 (which used cash during the 2004 period); and

These changes were offset by increased depletion, depreciation and amortization expense of $254,336 in 2005 compared to $156,000 in 2004.

Investing activities used cash to increase net capitalized oil and gas costs of $1,100,995 and $528,149 in the three months ended September 30, 2005 and 2004. Cash in the current three month period ended September 30, 2005 was used for lease acquisition, seismic work, intangible drilling and well workovers ($878,875), and the purchase of oil and gas well equipment ($222,120). These expenditures are net of 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 October through December 2005. The budget includes drilling four wells in the Sacramento gas province of northern California. Our share of the estimated costs to complete this program over the next three months is set forth in the following table:

Area	Wells	Drilling Costs	Comple Equippin
Denverton Creek Field, Solano County, CA	1	$170,000	

West Grimes Field Colusa County, CA	1	139,000	
Buckeye, Colusa County, CA	1	165,000	
Winters, Yolo County, CA	1	85,000	
Total Expenditure	4	$559,000	

Our working capital (current assets less current liabilities) at September 30, 2005, was $2,418,673, which reflects an approximate $190,700 decrease from our working capital at June 30, 2005. Our working capital declined by 7.3% during the first quarter of our 2005 fiscal year because of an increase in advances from joint owners of $325,000 that were not expended for drilling

projects at September 30, 2005, and an increase in accounts payable of $293,000. These increases were offset somewhat by the increase in cash and accounts receivable of $429,000. We anticipate that our working capital and anticipated cash flow from operations and future successful drilling will be sufficient to pay our current liabilities. Based on national and international concerns, we anticipate that our gas production will continue to provide us with sufficient cash flow through our current fiscal year and beyond. As discussed 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 the majority of 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. If our drilling efforts are successful, the anticipated increased cash flow from the new gas discoveries, in addition to our existing cash flow, should be sufficient to fund our share of planned future completion and pipeline costs.

Results of Operations

September 30, 2005 Compared to September 30, 2004

For the three months ended September 30, 2005, 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 2005, period our revenues increased by approximately $410,000 as compared to the comparable period of our 2004 fiscal year because of:

Increased production (146,400 MMBTU sold as compared to 130,000 MMBTU sold during the first three months of our 2004 fiscal year);

Increased price received for our production (an average of $7.26 per MMBTU during the first three months of our 2006 fiscal year as compared to $5.31 per MMBTU received during that period in 2005); and

Increased management fees received ($120,900 during fiscal 2006 as compared to $82,100 during fiscal 2005) because we were operators of more wells during 2006 (51 wells compared to 48 wells in 2005).

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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 three months of fiscal 2005, 2004, 2003 and 2002:

	For the Three Months Ended			
	9/30/05	9/30/2004	9/30/2003	9/30/2002
Total revenues	100.0%	100.0%	100.0%	100.0%
Oil & gas production costs	5.9	8.2	10.1	14.3
Income from operations	94.1	91.8	89.9	85.7
Costs and expenses				
Depreciation and depletion	21.3	19.9	32.9	32.2
Selling, general and administrative	19.0	21.8	44.1	70.1
Interest expense	.0	.3	.0	.0
Total costs and expenses	40.3	42.0	77.0	102.3
Income before income taxes	53.8	49.8	12.9	(16.6)
Provision for income taxes	15.1	21.4	.0	.0
Net income (loss)	38.7	28.4	12.9	(16.6)

To facilitate discussion of our operating results for the three months ended September 30, 2005 and 2004, we have included the following selected data from our Condensed Consolidated Statements of Operations:

Comparison of the Fiscal
Three Months Ended September 30, Inc

	2005	2004	Amoun
Revenues:			
Oil and gas sales	$1,062,543	$697,553	$ 364
Management fees	120,924	82,057	38
Interest and other	10,701	4,689	6
Total revenues	1,194,168	784,299	409
Cost and expenses:			
Oil and gas production	71,019	64,361	6
Depreciation and depletion	254,336	156,000	98
Selling, general and administrative	227,116	171,104	56
Interest expense	0	3,053	(3
Total costs and expenses	552,471	394,518	157
Income before taxes	641,697	389,781	
Provision for income taxes	180,395	168,163	
Net income	$461,302	$221,618	

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Central to the issue of success of the three months operations ended September 30, 2005 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
2006			
1st Quarter	$1,062,543	146,445	$7.26
2005			
1st Quarter	697,553	130,000	5.31
2nd Quarter	1,132,359	177,350	6.37
3rd Quarter	1,103,687	169,150	6.52
4th Quarter	919,578	145,500	6.30
Year to date	3,853,177	622,000	6.20
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
4th Quarter	481,441	80,600	5.97
Year to date	1,588,250	305,000	5.17
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
4th Quarter	314,445	60,600	5.19
Year to date	1,068,798	248,000	4.23
First Quarter change			
2006			
Amount	$364,990	16,445	$1.95
Percentage	52%	13%	37%
2005			
Amount	$355,627	57,400	$.56
Percentage	104%	79%	12%

(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 first three months of fiscal 2006 and during the twelve months of fiscal 2005. As the table above notes, revenue has increased approximately 52% when comparing the three month periods ended September 30, 2005 and 2004. Volumes sold increased approximately 13%, while the price received for our product increased 37%.

Total revenue increased $365,000, or 52% when comparing the two periods, while operating and production costs increased $6,660, or 10%. Our results during the current period were favorable in part because we were able to keep increases in our production costs significantly less than the increases in prices received for natural gas. The 10% increase in production costs is even less than the 13% increase in volumes produced.

A significant ratio presented is the percentage of management fees charged to operated wells versus our general and administrative costs. This coverage of

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general and administrative costs improved from approximately 48% for the three months ended September 30, 2004 to approximately 53% at September 30, 2005.

When comparing general and administrative expense for 2006 and 2005, costs increased approximately $56,000, or 33%, primarily because of increases in promotion and advertising ($24,000), accounting and audit fees ($13,000), legal fees, medical insurance, corporate reporting and consulting fees and other ($19,000).

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

Quarterly Financial Information (unaudited)

	Total Revenues	(1) Operating Income	(2) Income (loss) Before Income Taxes
2006			
1st Quarter	$1,194,168	$1,112,448	$641,697
2005			
1st Quarter	784,299	715,249	389,781
2nd Quarter	1,190,333	1,092,632	729,748
3rd Quarter	1,163,746	1,056,268	703,738
4th Quarter	980,926	908,704	382,957
Total	4,119,304	3,772,853	2,206,224
2004			
1st Quarter	388,337	348,739	50,197
2nd Quarter	433,317	365,761	93,022
3rd Quarter	440,127	354,642	76,762
4th Quarter	558,899	509,066	145,664
Total	1,820,680	1,578,208	365,645
2003			
1st Quarter	264,896	232,246	(44,238)
2nd Quarter	279,080	237,155	(15,660)
3rd Quarter	337,476	271,845	28,748
4th Quarter	432,369	272,421	133,876
Total	$1,313,821	$1,013,667	$102,726

(1) Operating income is oil and gas sales plus management fees less direct operating costs.
(2) Before provision for deferred income taxes.

As can be seen in the table, revenues and operating income have improved in every quarter when comparing the three month periods ended September 30, 2005 and 2004. 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 five contractual obligations as of September 30, 2005. The following table lists our significant liabilities at September 30, 2005:

	Payments Due By Period		
Contractual Obligations	Less than 1 year	2-3 years	4-5 years
Employment Obligations	$222,200	$468,200	$87,200
Contract Services Obligations	30,000	-0-	-0-
Operating Leases	9,500	1,600	-0-
Total contractual cash obligations	$261,700	$469,800	$87,200

We maintain office space in Denver, Colorado, our principal office, and Bakersfield, California. The Denver office consists of approximately 1,108 square feet with an additional 750 square feet of basement storage. We entered into a month to month lease agreement beginning January 1, 2005 on the Denver office 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 three months ended September 30, 2005 and 2004 was $6,163 and $6,033, 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 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.

Accounts Receivable:

Accounts receivable balances are evaluated on a continual basis and allowances are provided for potentially uncollectable accounts based on management's estimate of the collectability of customer accounts. If the financial condition of a customer were to deteriorate, resulting in an impairment of its ability to make payments, an additional 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.

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. Unregistered Sales of Equity Securities and Use of Proceeds.

None during the period

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.

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

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

November 10, 2005