ASPEN EXPLORATION CORP
Form 10QSB
February 10, 2006

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, 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 Aspen Exploration Corporation 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 February 9, 2006 |
|---|---|
| Common stock, $.005 par value | 6,776,641 |

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

| | December 31, 2005 | June 30, 2005 |
|---|---|---|
| Current Assets: | | |
| Cash and cash equivalents, including $2,455,406 and $2,812,971 of invested cash at December 31, 2005 and June 30, 2005 respectively .................................. | $ 3,370,131 | $ 3,430,146 |
| Accounts receivables .................................... | 1,511,881 | 614,720 |
| Receivable, related party ................................ | 38,153 | 13,000 |
| Prepaid expenses ......................................... | 10,283 | 15,422 |
| Precious metals .......................................... | 18,823 | 18,823 |
| Total current assets | 4,949,271 | 4,092,111 |
| Investment in oil and gas properties, at cost (full cost method of accounting) ..................................... | 11,890,506 | 9,670,383 |
| Less accumulated depletion and valuation allowance ........ | (5,087,090) | (4,587,090) |
| | 6,803,416 | 5,083,293 |
| Property and equipment, at cost: | | |
| Furniture, fixtures and vehicles ......................... | 122,576 | 154,819 |
| Less accumulated depreciation ............................ | (44,341) | (74,044) |
| | 78,235 | 80,775 |
| TOTAL ASSETS ........................................ | $ 11,830,922 | $ 9,256,179 |

(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

| | December 31, 2005 | June 30, 2005 |
|---|---|---|
| Current liabilities: | | |
| Accounts payable and accrued expenses ........... | $ 1,258,829 | $ 655,190 |
| Accounts payable - related party (Note 2) ....... | 8,267 | 103,233 |
| Income taxes payable (Note 7) .................. | 209,256 | 0 |
| Advances from joint interest owners ............ | 553,774 | 710,477 |
| Asset retirement obligation (Note 3) ........... | 40,494 | 13,826 |
| Total current liabilities ...................... | 2,070,620 | 1,482,726 |
| Asset retirement obligation, net of current portion (Note 3) ............................... | 81,716 | 82,384 |
| Deferred income taxes (Note 7) ................. | 1,378,286 | 1,015,488 |
| Total long term liabilities .................... | 1,460,002 | 1,097,872 |
| Total liabilities .............................. | 3,530,622 | 2,580,598 |
| Stockholders' equity: (Notes 1 and 5): | | |
| Common stock, $.005 par value: Authorized: 50,000,000 shares Issued and outstanding: At December 31, 2005, 6,768,308 shares and June 30, 2005, 6,733,308 | 33,841 | 33,666 |
| Capital in excess of par value ................. | 6,806,396 | 6,728,321 |
| Retained earnings (deficit) .................... | 1,497,396 | (69,169) |
| Deferred compensation and consulting fees ....... | (37,333) | (17,237) |
| Total stockholders' equity ..................... | 8,300,300 | 6,675,581 |
| Total liabilities and stockholders' equity ...... | $ 11,830,922 | $ 9,256,179 |

See Notes to Consolidated Financial Statements

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

| | Three Months Ended December 31, 2005 | Three Months Ended December 31, 2004 | Six Months Ended December 31, 2005 | Six Months Ended December 31, 2004 |
|---|---|---|---|---|
| Revenues: | | | | |
| Oil and gas ............................ | $ 2,017,233 | $ 1,132,359 | $ 3,079,776 | $ 1,829,9 |
| Management fees ........................ | 82,162 | 59,768 | 203,086 | 141,8 |
| Total Revenues .......................... | 2,099,395 | 1,192,127 | 3,282,862 | 1,971,7 |
| Costs and expenses: | | | | |

| | | | | |
|---|---|---|---|---|
| Oil and gas production ................ | 121,151 | 99,495 | 192,170 | 163,8 |
| Depreciation, depletion and amortization | 254,704 | 154,001 | 509,040 | 310,0 |
| Selling, general and administrative .... | 235,946 | 205,364 | 463,062 | 376,4 |
| Total Costs and Expenses ................ | 611,801 | 458,860 | 1,164,272 | 850,3 |
| Operating Income ........................ | 1,487,594 | 733,267 | 2,118,590 | 1,121,4 |
| Other income (expense) | | | | |
| Interest and other, net ............... | 9,328 | (1,794) | 20,029 | 2,8 |
| Interest (expense) .................... | 0 | (1,724) | 0 | (4,7 |
| Income before taxes ..................... | 1,496,922 | 729,749 | 2,138,619 | 1,119,5 |
| Provision for income taxes .............. | 391,659 | 267,674 | 572,054 | 435,8 |
| Net income .............................. | $ 1,105,263 | $ 462,075 | $ 1,566,565 | $ 683,6 |
| Basic income per common share ........... | $ .16 | $ .07 | $ .23 | $ . |
| Diluted income per common share ......... | $ .16 | $ .07 | $ .22 | $ . |
| Basic weighted average number of common shares outstanding ............... | 6,756,351 | 6,284,788 | 6,756,351 | 6,284,7 |
| Diluted weighted average number of common shares outstanding ............... | 7,125,295 | 6,576,591 | 7,125,295 | 6,576,5 |

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)

| | Six months ended December 31, 2005 | 2004 |
|---|---|---|
| Cash flows from operating activities: | | |
| Net income ....................................... | $ 1,566,565 | $ 683,692 |
| Adjustments to reconcile net income to net cash provided (used) by operating activities: | | |
| Depreciation, depletion and amortization ......... | 509,040 | 310,001 |
| Amortization of deferred compensation ............ | 43,904 | 15,082 |
| Deferred income tax provision .................... | 572,054 | 435,837 |
| Changes in assets and liabilities: | | |
| Increase in receivable ........................... | (922,314) | (81,703) |
| Decrease in prepaid expense ...................... | 5,139 | 7,724 |
| Increase in accounts payable and accrued expense . | 351,970 | 762,109 |
| Net cash provided by operating activities ........ | 2,126,358 | 2,132,742 |

| | | |
|---|---|---|
| **Cash flows from investing activities:** | | |
| Equipment inventory sale | 2,000 | 0 |
| Additions to oil and gas properties | (2,194,123) | (1,169,965) |
| Purchase of producing properties | 0 | (19,248) |
| Purchase of furniture and fixtures | (8,500) | (7,360) |
| Net cash (used) by investing activities | (2,200,623) | (1,196,573) |
| **Cash flow from financing activities:** | | |
| Common stock options exercised | 14,250 | 0 |
| Payment of notes payable | 0 | (75,000) |
| Net cash provided (used) by financing activities | 14,250 | (75,000) |
| Net increase/decrease in cash and cash equivalents | (60,015) | 861,169 |
| Cash and cash equivalents, beginning of year | 3,430,146 | 1,329,376 |
| Cash and cash equivalents, end of year | $ 3,370,131 | $ 2,190,545 |
| Other information: | | |
| Interest paid | $ 0 | $ 4,778 |
| Non-cash investing and financing activities | | |
| Asset retirement obligation additions | $ 26,000 | $ 8,000 |
| Stock issued for deferred consulting services | $ 64,000 | 0 |

The accompanying notes are an integral part of these statements.

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ASPEN EXPLORATION CORPORATION

Notes to Condensed Consolidated Financial Statements
(Unaudited)

December 31, 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, PAYABLE - 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. The payable from related parties represents unexpended prepayments made by officers and consultants on wells operated by us as well as unpaid business expenses due officers. These transactions are in the normal course of business.

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

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Note 3 ASSET RETIREMENT OBLIGATION (CONTINUED)

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 six months ended December 31, 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 December 31, 2005 | $122,210 |

*Accretion not material

Note 4 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.

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 $1,566,565 for the six months ended December 31, 2005 and $683,692 for the six months ended December 31, 2004.

| | Six Months Ended December 31, 2005 | | | December 31, 2004 | | |
|---|---|---|---|---|---|---|
| | Net Income | Shares | Per Share Amount | Net Income | Shares | Pe Sh Am |
| Basic earnings per share: | | | | | | |
| Net income and share amounts | $ 1,566,565 | 6,756,351 | $ .23 | $ 683,692 | 6,284,788 | $ |
| Dilutive securities: stock options | | 527,000 | | | 392,000 | |
| Repurchased shares | | (158,056) | | | (100,197) | |
| Diluted earnings per share: | | | | | | |
| Net income and assumed share conversion | $ 1,566,565 | 7,125,295 | $ .22 | $ 683,692 | 6,576,591 | $ |

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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 December 31, 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 Exercise Price of Shares Under Plans |
|---|---|---|
| Outstanding balance June 30, 2005 | 552,000 | $ 1.559 |
| Granted | -0- | -- |
| Exercised | (25,000) | .57 |
| Forfeited or expensed | -0- | -- |
| Outstanding balance December 31, 2005 | 527,000 | $ 1.606 |

The following table summarizes information concerning outstanding and exercisable options as of December 31, 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.

We have adopted SFAS Standards No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure" - an amendment of FASB Statement

No. 123. SFAS No. 148 amends No. SFAS 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



Note 5 STOCKHOLDERS' EQUITY (CONTINUED)

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. We will continue to account for stock based compensation using the methods detailed in the stock-based compensation accounting standard.

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 exercise price, is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions: no dividend yield, expected volatility of 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 in each of January 2006, 2007 and 2008.

Note 6 MAJOR CUSTOMERS

We derived in excess of 10% of our revenue from oil and gas sales made to two customers, as follows. One of these (Calpine Corporation, Customer B) has filed a petition for protection under the federal bankruptcy laws as described in Note 8, below.

| | The Company | |
|---|---|---|
| | A | B |
| Quarter ended: | | |
| December 31, 2005 | 66% | 26% |
| December 31, 2004 | 35% | 50% |

We do not believe that the concentration of our revenues from these two customers constitutes a significant risk to us because there are other customers available to purchase our oil and gas production, and because the market for oil and gas is driven by many factors beyond local economics and the relationship between a single customer and producer.

Note 7 INCOME TAXES

We have recorded a deferred income tax liability of $1,378,286 and an estimated current income tax liability of 209,256. During the first six months of fiscal 2006, we used all of our net operating loss carryforwards.

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



Note 7 INCOME TAXES (CONTINUED)

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.

At December 31, 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 | 2004 |
|---|---|---|
| Deferred tax assets: | | |
| Federal tax loss carryforwards | $ 0 | $ 285,462 |
| Asset retirement obligation | 133,354 | 4,727 |
| | 133,354 | 290,189 |
| Deferred tax (liabilities): | | |
| Property, plant and equipment | 521 | (1,855) |
| Oil and gas properties | (1,720,375) | (1,020,491) |
| | (1,720,896) | (1,022,346) |
| | $ 1,587,542 | $ 732,157 |

A reconciliation between the statutory federal income tax rate (34%) and the effective rate of income tax expense for the two six month periods ended December 31 is as follows:

| | 2005 | 2004 |
|---|---|---|
| Statutory federal income tax rate | 34% | 34% |
| Other | (3)% | (4)% |
| Net federal income tax rate | 31% | 30% |
| Statutory state income tax rate, net of federal benefit | 9% | 9% |

| | | |
|---|---|---|
| Effective rate | 40% | 39% |
| | === | === |



Note 7 INCOME TAXES (CONTINUED)

The provision for income taxes consists of the following components:

| | 2005 | 2004 |
|---|---|---|
| Current tax expense, state | $209,256 | $ 0 |
| Deferred tax expense | 362,798 | 435,837 |
| Total income tax provision | $572,054 | $435,837 |

Note 8 CONTINGENCIES AND DRILLING COMMITMENTS

On December 20, 2005 Calpine Corporation, one of our major purchasers of natural gas (currently purchases about 25% of our gas), filed for Chapter 11 bankruptcy protection in New York. At the time of the filing, Calpine Corporation owed us, exclusive of etal participation, approximately $193,000. We believe that the amount due to us at the filing will be collectible, but because of issues associated with all bankruptcies, we cannot offer any assurance that it will be collected. We will continue to monitor the situation with respect to collectibility and take further actions as we determine to be appropriate.

We have a proposed drilling budget for the period January through March 2006. The budget includes drilling seven wells in the Sacramento gas province of northern California and one well in Kern County, California. Our share of the estimated costs to complete this program is set forth in the following table:

| Area | Wells | Drilling Costs | Completion & Equipping Costs | Total |
|---|---|---|---|---|
| Denverton Creek Field, Solano County, CA | 2 | $ 380,000 | $ 130,000 | $ 510,000 |
| West Grimes Field Colusa County, CA | 3 | 264,000 | 80,000 | 344,000 |
| Malton Black Butte Field, Colusa County, CA | 2 | 168,000 | 87,000 | 255,000 |
| San Emidio Field, Kern County, CA | 1 | 203,000 | 56,000 | 259,000 |
| Total Expenditure | 8 | $1,015,000 | $ 353,000 | $1,368,000 |

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Note 9 NEW ACCOUNTING PRONOUNCEMENTS

FASB 151 - Inventory Costs

In November 2004, the FASB issued FASB Statement No. 151, which revised ARB No. 43, relating to inventory costs. This revision is to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted material (spoilage). This Statement requires that these items be recognized as a current period charge regardless of whether they meet the criterion specified in ARB 43. In addition, this Statement requires the allocation of fixed production overheads to the costs of conversion be based on normal capacity of the production facilities. This Statement became effective for financial statements for fiscal years beginning after June 15, 2005. Management believes this Statement has not any and will not have any material impact on our financial statements.

FASB 153 - Exchanges of Non-monetary Assets

In December 2004, the FASB issued FASB Statement No. 153. This Statement addresses the measurement of exchanges of non-monetary assets. The guidance in APB Opinion No. 29, "Accounting for Non-monetary Transactions", is based on the principle that exchanges of non-monetary assets should be measured based on the fair value of the assets exchanged. The guidance in that Opinion, however, included certain exceptions to that principle. This Statement amends Opinion 29 to eliminate the exception for non-monetary exchanges of similar productive assets and replaces it with a general exception for exchanges of non-monetary assets that do not have commercial substance. A non-monetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. This Statement is effective for financial statements for fiscal years beginning after June 15, 2005. Earlier application is permitted for non-monetary asset exchanges incurred during fiscal years beginning after the date of this Statement is issued. Management believes this Statement will have no impact on our financial statements.

FASB 123 (revised 2004) - Share-Based Payments

In December 2004, the FASB issued a revision to FASB Statement No. 123, "Accounting for Stock Based Compensation". This Statement supersedes APB Opinion No. 25, "Accounting for Stock Issued to Employees", and its related implementation guidance. This Statement establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. It also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. This Statement focuses primarily on accounting for transactions in which an entity obtains employee services in share-based payment transactions. This Statement does not change the accounting guidance for share-based payment transactions with parties other than employees provided in Statement 123 as originally issued and EITF Issue No. 96-18, "Accounting for Equity Instruments That Are Issued to Other Than Employees for Acquiring, or in Conjunction with Selling, Goods or Services." This Statement does not address the accounting for employee share ownership plans, which are subject to AICPA Statement of Position 93-6, Employers' Accounting for Employee Stock Ownership Plans.

Note 9 NEW ACCOUNTING PRONOUNCEMENTS (CONTINUED)

A nonpublic entity will measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of those instruments, except in certain circumstances.

A public entity will initially measure the cost of employee services received in exchange for an award of liability instruments based on its current fair value; the fair value of that award will be re-measured subsequently at each reporting date through the settlement date. Changes in fair value during the requisite service period will be recognized as compensation cost over that period. A nonpublic entity may elect to measure its liability awards at their intrinsic value through the date of settlement.

The grant-date fair value of employee share options and similar instruments will be estimated using the option-pricing models adjusted for the unique characteristics of those instruments (unless observable market prices for the same or similar instruments are available).

Excess tax benefits, as defined by this Statement, will be recognized as an addition to paid-in-capital. Cash retained as a result of those excess tax benefits will be presented in the statement of cash flows as financing cash inflows. The write-off of deferred tax assets relating to unrealized tax benefits associated with recognized compensation cost will be recognized as income tax expense unless there are excess tax benefits from previous awards remaining in paid-in capital to which it can be offset.

The notes to the financial statements of both public and nonpublic entities will disclose information to assist users of financial information to understand the nature of share-based payment transactions and the effects of those transactions on the financial statements.

The effective date for public entities that do not file as small business issuers will be as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. For public entities that file as small business issuers and nonpublic entities the effective date will be as of the beginning of the first interim or annual reporting period that begins after December 15, 2005. Management has complied with this Statement as of the effective date.

Note 10 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 gas pay in several intervals in the Forbes formation. Several of these Forbes intervals were perforated and tested gas on a 1/4 inch choke at a flow rate of 2,909 MCFPD with a flowing tubing pressure of 2,005 psig. Gas sales commenced on January 13, 2006 at a flow rate of 1,750 MCFPD with a flowing tubing pressure of 2,500 psig. Aspen has a 30.625% operated working interest in this well.

The Merrill #31-2 well located in the Malton Black Butte Field, Tehama County, California, was drilled to a depth of 2,450 feet and encountered approximately 40 feet of potential gas pay in the Lower Kione formation. Production casing was run based on favorable mud log and electric log responses. This well also encountered approximately 100 gross feet of partially depleted gas sand in the Upper Kione formation, which yielded

Note 10 SUBSEQUENT EVENTS (CONTINUED)

valuable data regarding the possibility of drilling a future under balanced horizontal well in this zone. The Upper Kione is a prolific gas producing zone in this area. Aspen has a 31% 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'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 discussed herein and 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 54 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 44% 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 commence gas sales, 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 $4.00 to $10.00 per MMBTU for the fiscal year ended June 30, 2006 as compared to the average gas price of $6.20 received 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 three years, from a low of $3.76 per MMBTU average during the second quarter of fiscal 2003 to $10.14 per MMBTU for the quarter ended December 31, 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.

The prices that we receive for the oil and natural gas (including natural gas liquids) produced are impacted by many factors that are outside of our control. Historically, these commodity prices have been volatile and we expect them to remain volatile. Prices for oil and natural gas are affected by changes in market demands, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, the world political situation, basis differentials and other factors. As a result, we cannot accurately predict future natural gas and NGL (natural gas liquids) prices, and therefore, we cannot determine what effect increases or decreases in production volumes will have on future revenues.

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

To manage commercial risk, we may use financial tools to hedge the price we will receive for our product. The primary purpose of hedging is to provide adequate return on our investments, grow our reserves while leaving as much commodity price upside as possible. 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 six months of fiscal 2006 for our natural gas was approximately $8.85 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 $2,126,358 and $2,132,742 was provided by our operations for the six months ended December 31, 2005 and 2004. The 2005 period generated net income of $1,566,565, and we were able to generate increased positive cash flow from operations during the first six months of fiscal 2006 as compared to the 2005 period (when we generated net income of $683,692) because of:

An increase in oil and gas sales (68%) due to increased volumes sold (13%) and price received for our gas (49%); and

An increase in accounts payable and accrued expenses of $351,970 in 2005 (which conserved cash) compared to an increase in accounts payable and accrued expenses of $762,109; and

These changes were offset by increased estimated depletion, depreciation and amortization expense of $509,040 in 2006 compared to $310,001 in 2005.

Investing activities used cash to increase net capitalized oil and gas costs and office equipment of $2,200,623 and $1,196,573 in the six months ended December 31, 2005 and 2004. Cash in the current six month period ended December 31, 2005 was used for lease acquisition, seismic work, intangible drilling and well workovers ($1,732,653), the purchase of oil and gas well equipment ($459,470), and office equipment of ($8,500). These expenditures are net of the sale of interests in wells to be drilled charged to third party investors.

We have a proposed drilling budget for the period January through March 2006. The budget includes drilling seven wells in the Sacramento gas province of northern California and one well in Kern County, California. Our share of the estimated costs to complete this program is set forth in the following table:

| Area | Wells | Drilling Costs | Completion & Equipping Costs | Total |
|---|---|---|---|---|
| Denverton Creek Field, Solano County, CA | 2 | $ 380,000 | $ 130,000 | $ 510,000 |
| West Grimes Field Colusa County, CA | 3 | 264,000 | 80,000 | 344,000 |
| Malton Black Butte Field, Colusa County, CA | 2 | 168,000 | 87,000 | 255,000 |
| San Emidio Field, Kern County, CA | 1 | 203,000 | 56,000 | 259,000 |
| Total Expenditure | 8 | $1,015,000 | $ 353,000 | $1,368,000 |



Our working capital (current assets less current liabilities) at December 31, 2005, was $2,878,651, which reflects an approximate $269,000 increase from our working capital at June 30, 2005. Our working capital increased by 10.3% during the first six months of our 2006 fiscal year because of

an increase in accounts receivable ($1,511,881 at December 31, 2005 as compared to $614,720 at June 30, 2005) due to larger production volumes and greater prices received during the period and the Calpine Corporation bankruptcy (leaving a receivable of approximately $193,000 net of etal participation that (at this time) we believe is collectible);

a decrease in advances from joint owners of $156,700 and accounts payable-related parties of approximately $90,000 that were not expended for drilling projects at December 31, 2005,

which were partially offset by an increase in accounts payable of $508,700 and an increase in taxes payable of $209,000 and a decrease during the period in cash of approximately $60,000.

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

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

### December 31, 2005 Compared to December 31, 2004

For the six months ended December 31, 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 $1,311,125 as compared to the comparable period of our 2004 fiscal year because of:

Increased production (347,800 MMBTU sold as compared to 307,400 MMBTU sold during the first six months of our 2004 fiscal year);

Increased price received for our production (an average of $8.82 per MMBTU during the first six months of our 2006 fiscal year as compared to $5.92 per MMBTU received during that period in 2005); and

Increased management fees received ($203,100 during fiscal 2006 as compared to $141,800 during fiscal 2005) because we were operators of more wells during 2006 (54 wells compared to 48 wells in 2005).

Our revenues during the second quarter include revenues accrued from (but not paid by) Calpine Corporation because of its bankruptcy proceeding. We believe that such revenues are collectible and will be collected. If those revenues are ultimately not collected, then our revenues for the three and six months ended December 31, 2005, will decrease by approximately $193,000 of pre-petition receivables and any unpaid post-petition receivables. (See further discussion in Note 8 to the financial statements and "Accounts Receivable," below.)



The following table sets forth certain items from our Condensed Consolidated Statements of Operations as expressed as a percentage of total revenues for the six months of fiscal 2005, 2004, 2003 and 2002:

| | For the Six Months Ended | | | |
|---|---|---|---|---|
| | 12/31/2005 | 12/31/2004 | 12/31/2003 | 12/31/20 |
| Total revenues | 100.0% | 100.0% | 100.0% | 10 |
| Oil & gas production costs | 5.9 | 8.3 | 12.5 | 1 |
| Income from operations | 94.1 | 91.7 | 87.5 | 8 |

| | | | | |
|---|---|---|---|---|
| Costs and expenses | | | | |
| Depreciation and depletion | 15.5 | 15.7 | 31.4 | 3 |
| Selling, general and administrative | 14.1 | 19.0 | 38.6 | 6 |
| Interest expense | - | - | - | |
| Total costs and expenses | 29.6 | 34.7 | 70.0 | 9 |
| Income before income taxes | 64.5 | 57.0 | 17.5 | (1 |
| Other income | (.6) | - | - | |
| Provision for income taxes | 17.4 | 22.1 | - | |
| Net income (loss) | 47.7 | 34.9 | 17.5 | (1 |

To facilitate discussion of our operating results for the six months ended December 31, 2005 and 2004, we have included the following selected data from our Condensed Consolidated Statements of Operations:

| | Comparison of the Fiscal Six Months Ended December 31, | | Increase (Decrease) | |
|---|---|---|---|---|
| | 2005 | 2004 | Amount | Percentage |
| Revenues: | | | | |
| Oil and gas sales | $ 3,079,776 | $ 1,829,912 | $ 1,249,864 | 68% |
| Management fees | 203,086 | 141,825 | 61,261 | 43 |
| Interest and other | 20,029 | 2,895 | 17,134 | 591 |
| Total revenues | 3,302,891 | 1,974,632 | 1,328,259 | 67 |
| Cost and expenses: | | | | |
| Oil and gas production | 192,170 | 163,856 | 28,314 | 17 |
| Depreciation and depletion | 509,040 | 310,001 | 199,039 | 64 |
| General and administrative | 463,062 | 376,468 | 86,594 | 23 |
| Interest expense | -- | 4,778 | (4,778) | 100 |
| Total costs and expenses | 1,164,272 | 855,103 | 309,169 | 36 |
| Income before taxes | 2,138,619 | 1,119,529 | 1,019,090 | 91 |
| Provision for income taxes | 572,054 | 435,837 | 136,217 | 31 |
| Net income | 1,566,565 | $ 683,692 | $ 882,873 | 129% |



Central to the issue of success of the six months operations ended December 31, 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 MMBTU (1)

| | Sales | Sold | Price/MMBTU |
|---|---|---|---|
| 2006 | | | |
| 1st Quarter | $1,062,543 | 146,445 | $7.26 |
| 2nd Quarter | 2,017,233 | 201,371 | 10.14 |
| Year to date | 3,079,776 | 347,816 | 8.85 |
| 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 |
| Second Quarter change | | | |
| 2006 | | | |
| Amount | $884,874 | 24,021 | $3.77 |
| Percentage | 78% | 14% | 59% |
| 2005 | | | |
| Amount | $769,417 | 97,450 | $1.73 |
| Percentage | 212% | 122% | 37% |

(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 six months of fiscal 2006 and during the twelve months of fiscal 2005. As the table above notes, revenue has increased approximately 78% when comparing the two three month periods ended December 31, 2005 and 2004. Volumes sold increased approximately 14%, while the price received for our product increased 59%.

Total revenue increased $884,874, or 78% when comparing the two periods, while operating and production costs increased $21,656, or 22%. 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 22% increase in production costs is even less than the 78% increase in oil and gas sales.



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 38% for the six months ended December 31, 2004 to approximately 44% at December 31, 2005.

When comparing general and administrative expense for 2006 and 2005, costs increased approximately $86,600, or 23%, primarily because of increases in promotion and advertising ($58,900), accounting and audit fees ($11,300), legal fees, medical insurance, corporate reporting and consulting fees and other ($16,400).

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 | In Befor P Basic |
|---|---|---|---|---|
| 2006 | | | | |
| 1st Quarter | $1,194,168 | $1,112,448 | $641,697 | $.095 |
| 2nd Quarter | 2,108,723 | 1,978,244 | 1,496,922 | .222 |
| Year to date | 3,302,891 | 3,090,692 | 2,138,619 | .31 |
| 2005 | | | | |
| 1st Quarter | 784,299 | 715,249 | 389,781 | .063 |
| 2nd Quarter | 1,190,333 | 1,092,632 | 729,749 | .116 |
| 3rd Quarter | 1,163,746 | 1,056,268 | 703,738 | .109 |
| 4th Quarter | 980,926 | 908,704 | 382,957 | .059 |
| Total | 4,119,304 | 3,772,853 | 2,206,224 | .34 |
| 2004 | | | | |
| 1st Quarter | 388,337 | 348,739 | 50,197 | .008 |
| 2nd Quarter | 433,317 | 365,761 | 93,022 | .016 |
| 3rd Quarter | 440,127 | 354,642 | 76,762 | .013 |
| 4th Quarter | 558,899 | 509,066 | 145,664 | .025 |
| Total | 1,820,680 | 1,578,208 | 365,645 | .06 |
| 2003 | | | | |
| 1st Quarter | 264,896 | 232,246 | (44,238) | (.008) |
| 2nd Quarter | 279,080 | 237,155 | (15,660) | (.003) |
| 3rd Quarter | 337,476 | 271,845 | 28,748 | .005 |

| | | | | |
|---|---|---|---|---|
| 4th Quarter | 432,369 | 272,421 | 133,876 | .023 |
| Total | $1,313,821 | $1,013,667 | $102,726 | $.02 |

(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 six month periods ended December 31, 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.

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Contractual Obligations:

We had five contractual obligations as of December 31, 2005. The following table lists our significant liabilities at December 31, 2005:

| | Payments Due By Period | | | | |
|---|---|---|---|---|---|
| Contractual Obligations | Less than 1 year | 2-3 years | 4-5 years | After 5 years | Total |
| Employment Obligations | $226,000 | $512,000 | $27,000 | $-0- | $765,000 |
| Contract Services Obligations | 15,000 | -0- | -0- | -0- | 15,000 |
| Operating Leases | 9,500 | -0- | -0- | -0- | 9,500 |
| Total contractual cash obligations | $250,500 | $512,000 | $27,000 | $-0- | $789,500 |

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 six months ended December 31, 2005 and 2004 was $12,474 and $12,270, 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 uncollectible accounts based on management's estimate of the collectibility of customer accounts. If the financial condition of a customer were to deteriorate, resulting in an impairment of its ability to make payments, an 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. At the present time, we believe that we will collect the full amount of the pre-petition and post-petition receivables from Calpine Corporation (notwithstanding its bankruptcy petition). We will continue to monitor this situation and revise our estimates as appropriate.

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:
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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.

Off Balance Sheet Arrangements:
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We have no off balance sheet arrangements and thus no disclosure is required.



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

February 9, 2006

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