PRIMA ENERGY CORP
Form 10-Q
November 13, 2003

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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

[**x**] QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2003

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _______ to _______

Commission file number **0-9408**

PRIMA ENERGY CORPORATION

(Exact name of Registrant as specified in its charter)

Delaware	**84-1097578**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1099 18th Street, Suite 400, Denver CO 80202
(Address of principal executive offices) (Zip Code)

(303) 297-2100
(Registrant s telephone number, including area code)

No Change
(Former name, former address and former fiscal year, if changed from last report.)

Indicate by check mark whether the Registrant (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 the Registrant 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 an accelerated filer (as defined in Rule 12-b-2 of the Exchange Act). Yes [**x**] No [ ]

As of October 31, 2003, the Registrant had 12,910,142 shares of Common Stock, $0.015 Par Value, outstanding.

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

PRIMA ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

ASSETS

	September 30, 2003	December 31, 2002
	(Unaudited)	
CURRENT ASSETS		
Cash and cash equivalents	$ 50,358,000	$ 36,263,000
Available for sale securities, at market	1,517,000	1,744,000
Receivables (net of allowance for doubtful accounts: 9/30/03, $302,000; 12/31/02, $304,000)	10,581,000	7,492,000
Derivatives, at fair value	131,000	
Tubular goods inventory	995,000	940,000
Other	519,000	818,000
Total current assets	64,101,000	47,257,000
OIL AND GAS PROPERTIES, at cost, accounted for using the full cost method	169,353,000	151,518,000
Less accumulated depreciation, depletion and amortization	(71,928,000)	(62,980,000)
Oil and gas properties net	97,425,000	88,538,000
PROPERTY AND EQUIPMENT, at cost		
Oilfield service equipment	9,961,000	9,457,000
Furniture and equipment	687,000	712,000
Field office, shop and land	478,000	478,000
	11,126,000	10,647,000
Less accumulated depreciation	(6,430,000)	(5,808,000)
Property and equipment net	4,696,000	4,839,000
OTHER ASSETS	1,298,000	1,293,000
	$ 167,520,000	$ 141,927,000

See accompanying notes to unaudited consolidated financial statements.

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PRIMA ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS (cont d.)

LIABILITIES AND STOCKHOLDERS EQUITY

	September 30, 2003	December 31, 2002
	(Unaudited)	
CURRENT LIABILITIES		
Accounts payable	$ 3,620,000	$ 3,129,000
Amounts payable to oil and gas property owners	3,089,000	3,192,000
Ad valorem and production taxes payable	2,663,000	3,864,000
Accrued and other liabilities	1,648,000	893,000
Derivatives, at fair value		225,000
Total current liabilities	11,020,000	11,303,000
AD VALOREM TAXES, non-current	3,084,000	2,077,000
ASSET RETIREMENT OBLIGATIONS	1,860,000	
DEFERRED TAX LIABILITY	26,491,000	21,281,000
Total liabilities	42,455,000	34,661,000
STOCKHOLDERS EQUITY		
Preferred stock, $0.001 par value, 2,000,000 shares authorized; no shares issued or outstanding		
Common stock, $0.015 par value, 35,000,000 shares authorized; 13,258,548 and 13,064,048 shares issued	199,000	196,000
Additional paid-in capital	7,554,000	5,250,000
Retained earnings	124,708,000	107,470,000
Accumulated other comprehensive income (loss)	250,000	(115,000)
Treasury stock, 348,406 and 236,538 shares at cost	(7,646,000)	(5,535,000)
Total stockholders equity	125,065,000	107,266,000
	$ 167,520,000	$ 141,927,000

See accompanying notes to unaudited consolidated financial statements.

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PRIMA ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	**2002**	**2003**	**2002**
REVENUES				
Oil and gas sales	$15,259,000	$ 5,455,000	$41,605,000	$17,460,000
Gains (losses) on derivatives instruments, net	680,000	(143,000)	1,986,000	(2,780,000)
Oilfield services	2,207,000	1,964,000	6,335,000	6,403,000
Interest, dividend and other income	83,000	156,000	353,000	474,000
	18,229,000	7,432,000	50,279,000	21,557,000
EXPENSES				
Depreciation, depletion and amortization:				
Depletion of oil and gas properties	3,599,000	2,320,000	10,358,000	6,757,000
Depreciation of property and equipment	236,000	202,000	798,000	846,000
Lease operating expense	805,000	685,000	2,600,000	2,261,000
Ad valorem and production taxes	1,444,000	448,000	4,010,000	1,413,000
Cost of oilfield services	1,470,000	1,779,000	4,917,000	5,258,000
General and administrative	837,000	772,000	2,471,000	2,388,000
	8,391,000	6,206,000	25,154,000	18,923,000
Income before income taxes and cumulative effect of change in accounting principle	9,838,000	1,226,000	25,125,000	2,634,000
Provision for income taxes	3,245,000	200,000	8,290,000	340,000
Net income before cumulative effect of change in accounting principle	6,593,000	1,026,000	16,835,000	2,294,000
Cumulative effect of change in accounting principle			403,000	
NET INCOME	$ 6,593,000	$ 1,026,000	$17,238,000	$ 2,294,000
Basic net income per share before cumulative effect of change in accounting principle	$ 0.51	$ 0.08	$ 1.32	$ 0.18
Cumulative effect of change in accounting principle			0.03	
BASIC NET INCOME PER SHARE	$ 0.51	$ 0.08	$ 1.35	$ 0.18
Diluted net income per share before cumulative effect of change in accounting principle	$ 0.50	$ 0.08	$ 1.29	$ 0.17
Cumulative effect of change in accounting principle			0.03	
DILUTED NET INCOME PER SHARE	$ 0.50	$ 0.08	$ 1.32	$ 0.17

Weighted Average Common Shares Outstanding	12,817,576	12,772,513	12,790,069	12,768,043
Weighted Average Common Shares Outstanding Assuming Dilution	13,080,193	13,221,889	13,039,712	13,261,851

See accompanying notes to unaudited consolidated financial statements.

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PRIMA ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Net income	$6,593,000	$1,026,000	$17,238,000	$2,294,000
Other comprehensive income (loss):				
Change in fair value of hedges	321,000	(126,000)	500,000	(897,000)
Reclassification adjustment for realized losses (gains) on hedges included in net income	(350,000)	254,000	9,000	413,000
Deferred income tax (expense) benefit related to change in fair value of hedges	11,000	(47,000)	(188,000)	179,000
Change in fair value of available-for-sale securities	(46,000)	20,000	11,000	45,000
Reclassification adjustment for realized (gains) losses included in net income		(27,000)	59,000	(66,000)
Deferred income tax (expense) benefit related to change in fair value of available-for-sale securities	16,000	3,000	(26,000)	8,000
	(48,000)	77,000	365,000	(318,000)
COMPREHENSIVE INCOME	$6,545,000	$1,103,000	$17,603,000	$1,976,000

See accompanying notes to unaudited consolidated financial statements.

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PRIMA ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Nine Months Ended September 30,	
	2003	2002
OPERATING ACTIVITIES		
Net income	$ 17,238,000	$ 2,294,000
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	11,156,000	7,603,000
Deferred income taxes	4,931,000	(823,000)
Cumulative effect of change in accounting principle	(403,000)	
Unrealized losses on derivatives instruments	154,000	4,500,000
Tax benefit from exercise of employee stock options	1,411,000	824,000
Other	(64,000)	6,000
Changes in operating assets and liabilities:		
Receivables	(3,094,000)	(206,000)
Inventory	(55,000)	183,000
Other current assets	147,000	67,000
Accounts payable and payables to owners	388,000	1,220,000
Production taxes payable	(194,000)	(1,739,000)
Accrued and other liabilities	755,000	(603,000)
Net cash provided by operating activities	32,370,000	13,326,000
INVESTING ACTIVITIES		
Additions to oil and gas properties	(18,287,000)	(12,040,000)
Proceeds from sales of oil and gas properties	1,664,000	13,544,000
Purchases of other property, net	(793,000)	(496,000)
Proceeds from sales of available for sale securities, net	356,000	692,000
Net cash provided by (used in) investing activities	(17,060,000)	1,700,000
FINANCING ACTIVITIES		
Treasury stock purchased	(2,111,000)	(1,669,000)
Proceeds from common stock issued	896,000	477,000
Net cash used in financing activities	(1,215,000)	(1,192,000)
INCREASE CASH AND CASH EQUIVALENTS	14,095,000	13,834,000
CASH AND CASH EQUIVALENTS, beginning of period	36,263,000	23,337,000
CASH AND CASH EQUIVALENTS, end of period	$ 50,358,000	$ 37,171,000

See accompanying notes to unaudited consolidated financial statements.

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PRIMA ENERGY CORPORATION
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL

Prima Energy Corporation is an independent oil and gas company primarily engaged in the exploration for, and the acquisition, development and production of, crude oil and natural gas. Through wholly owned subsidiaries, we also conduct operations in oil and gas property management, oilfield services and natural gas gathering, marketing and trading. These activities have been conducted predominantly in the Rocky Mountain region of the United States.

Our consolidated financial statements include the accounts of Prima Energy Corporation and its subsidiaries, which are collectively referred to in this report as Prima. All significant intercompany transactions have been eliminated.

Financial information presented herein as of September 30, 2003 and for the nine-month periods ended September 30, 2003 and 2002 is unaudited but reflects all adjustments that we believe are necessary to fairly present Prima s financial position, results of operations and cash flows for the periods shown. Such adjustments consist only of normal recurring accruals. Certain prior-year amounts have also been reclassified to conform to classifications reflected as of September 30, 2003. Results for interim periods are not necessarily indicative of results to be expected for our full fiscal year ending December 31, 2003.

The consolidated financial statements presented in this Form 10-Q should be read in conjunction with the Notes to Consolidated Financial Statements that were included in Prima s Annual Report on Form 10-K filed for the year ended December 31, 2002.

2. ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2003, we adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*. SFAS No. 143 provides that, if the fair value for an asset retirement obligation can be reasonably estimated, the liability should be recognized in the period in which it is incurred. Oil and gas producing companies typically incur such liabilities upon drilling or acquiring wells. Under the method prescribed by SFAS No. 143, an asset retirement obligation is recorded as a liability at its estimated present value at the asset s inception, with an offsetting charge to property cost. The corresponding property cost, less the estimated undiscounted salvage value, is then included in the calculation of depletion cost for oil and gas properties. Periodic accretion of discount of the estimated liability is also recorded in the income statement. Prior to adoption of SFAS No. 143, we accrued for any estimated asset retirement obligation, net of estimated salvage value, as part of our calculation of depletion, depreciation and amortization. Under this method, the estimated net cost of the obligation would be recognized over the life of the property on a unit-of-production basis, with the estimated obligation netted in property cost as part of the accumulated depreciation, depletion and amortization balance. Based on our experience that salvage values have generally equaled or exceeded abandonment costs for the types of properties that Prima has owned to date, such net costs have been negligible.

Our asset retirement obligation primarily represents the estimated present value of the amount we project will be incurred to plug, abandon and remediate our oil and gas properties at the end of their productive lives, in accordance with applicable laws and regulations. Our adoption of SFAS No. 143 as

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of January 1, 2003 resulted in the recognition of an increase in the carrying value of our oil and gas properties of $2,252,000, an increase in our deferred tax liability of $217,000, an increase in other non-current liabilities of $1,632,000, and a net-of-tax adjustment increasing net income by $403,000, which was recorded as the cumulative effect of a change in accounting principle. The estimated pro forma effect of January 1, 2002 adoption of SFAS No. 143 on net income and earnings per share for interim and annual periods in 2002 is not material. A reconciliation of Prima s liability for the nine months ended September 30, 2003 is as follows:

	Nine Months Ended September 30, 2003
Upon Adoption at January 1, 2003	$ 1,632,000
Liabilities incurred	127,000
Liabilities settled	0
Accretion expense	101,000
Revision to estimate	0
	$ 1,860,000

3. DERIVATIVES TRANSACTIONS

From time to time, we have used crude oil and natural gas futures, options and swaps, to mitigate risks associated with fluctuating oil and natural gas prices and basis differentials. While the use of such derivatives can reduce the adverse effects of oil and gas price declines or increases in basis differentials, they also generally limit the benefits of price increases.

All derivative financial instruments are recorded on the balance sheet at fair value. Fair value is generally determined based on the difference between the fixed contract price and the underlying market price at the determination date, and/or the value confirmed by the counterparty. Changes in the fair value of effective cash flow hedges are recorded as a component of accumulated other comprehensive income (loss), which is later included in oil and gas sales when the hedged transaction occurs. Changes in the fair value of derivatives that are not designated as hedges, as well as any ineffective portion of hedge derivatives, are recorded in gains (losses) on derivative instruments, net in the income statement.

Giving consideration to our current sources of oil and gas production, we have determined that, swaps, collars, puts or floors that are based on NYMEX oil prices or CIG gas prices qualify as effective cash flow hedges. Derivatives based on NYMEX gas prices will not qualify unless we have entered into corresponding transactions to hedge basis differentials between NYMEX and CIG indices. In addition, stand-alone basis-differential swaps and sales of call options do not qualify for hedge accounting.

In the first nine months of 2003, $9,000 of losses on derivative transactions that qualified for hedge accounting were included in oil and gas sales, compared to $413,000 of losses for the same period of 2002. In addition, we recognized net gains on derivatives instruments not qualifying for hedge accounting in the first nine months of 2003 totaling $1,986,000 and net losses on such instruments in the first nine months of 2002 aggregating $2,780,000. These non-hedge derivatives primarily related to NYMEX gas swaps for which we did not elect to enter into corresponding swaps for Rocky Mountain basis differentials.

As of September 30, 2003, Prima had recorded a net current asset of $131,000, representing the aggregate unrealized mark-to-market gains for its open derivative positions (all relating to oil) at that date. These positions are summarized below:

Time Period	Market Index	Total Volumes (Bbls)	Contract Price	Unrealized Gains
November December 2003	NYMEX	30,000	$30.94	$ 56,000
January March 2004	NYMEX	45,000	29.75	75,000
Total Unrealized Gains				$131,000

4. EARNINGS PER SHARE

Basic net income per share is computed by dividing net income by the weighted average number of common shares outstanding during the period. Diluted net income per share reflects the potential dilution that could occur upon exercise of options to acquire common stock, computed using the treasury stock method. The treasury stock method assumes that the number of additional shares that could be issued is reduced by the number of shares that could have been repurchased with proceeds that Prima would receive upon exercise of the options. The amount of shares that could have been repurchased was determined using the average market price of our common stock during the reporting period.

The following table reconciles the net earnings and common shares outstanding that were used in the calculations of basic and diluted net income per share for the quarter and nine months ended September 30, 2003 and 2002.

	Income (Numerator)	Shares (Denominator)	Per Share Amount
Quarter Ended September 30, 2003:			
Basic Net Income per Share	$ 6,593,000	12,817,576	$ 0.51
Effect of Stock Options		262,617	
Diluted Net Income per Share	$ 6,593,000	13,080,193	$ 0.50
Quarter Ended September 30, 2002:			
Basic Net Income per Share	$ 1,026,000	12,772,513	$ 0.08
Effect of Stock Options		449,376	
Diluted Net Income per Share	$ 1,026,000	13,221,889	$ 0.08
Nine Months Ended September 30, 2003:			
Basic Net Income per Share	$17,238,000	12,790,069	$ 1.35
Effect of Stock Options		249,643	
Diluted Net Income per Share	$17,238,000	13,039,712	$ 1.32
Nine Months Ended September 30, 2002:			
Basic Net Income per Share	$ 2,294,000	12,768,043	$ 0.18
Effect of Stock Options		493,808	
Diluted Net Income per Share	$ 2,294,000	13,261,851	$ 0.17

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5. STOCK-BASED COMPENSATION

Prima has stock-based compensation plans for its employees and its non-employee directors. We account for stock-based compensation using the intrinsic value recognition and measurement principles prescribed in Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees* and related interpretations. No stock-based compensation expense for employees or non-employee directors is reflected in net income, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant.

For disclosure purposes, the fair value of options is measured at the date of grant using the Black-Scholes option valuation model, which was developed for use in estimating the fair value of traded options that have no vesting restrictions and are fully transferable. Such option valuation models require the input of highly subjective assumptions. Because options issued under Prima s stock-based compensation plans have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the estimated fair value, these valuation models do not necessarily provide a reliable measure of the fair value of such stock options.

For purposes of pro forma disclosures, the measured fair values of option grants are amortized to expense over the options vesting periods. The following table illustrates the effect on net income and earnings per share if we had applied the fair value recognition provisions of Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation*.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	**2002**	**2003**	**2002**
Net Income				
As reported	$6,593,000	$1,026,000	$17,238,000	$2,294,000
Pro forma	$6,339,000	$ 804,000	$16,476,000	$1,628,000
Basic Net Income Per Share				
As reported	$ 0.51	$ 0.08	$ 1.35	$ 0.18
Pro forma	$ 0.49	$ 0.06	$ 1.29	$ 0.13
Diluted Net Income Per Share				
As reported	$ 0.50	$ 0.08	$ 1.32	$ 0.17
Pro forma	$ 0.48	$ 0.06	$ 1.26	$ 0.12

6. INDUSTRY SEGMENT INFORMATION

Prima organizes its activities into two operating segments consisting of: 1) the acquisition, exploration, development and operation of oil and gas properties; and 2) providing oilfield services for wells that we operate and for third-party operators. Our activities have been conducted primarily in the Rocky Mountain region of the United States, which is one geographic area.

The information below presents the operating segment data for Prima on the basis used by management in deciding how to allocate resources and in assessing performance, which is the same basis used in the preparation of our consolidated financial statements. Total revenue by operating segment includes both sales to unaffiliated customers, as reported in our consolidated statements of income, and intersegment sales that are eliminated in consolidation, which represent oilfield services provided for Prima-operated wells. Oilfield services are priced and revenues are accounted for consistently for both unaffiliated and intersegment sales.

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	**2002**	**2003**	**2002**
Revenues				
Oil & gas (including derivative effects)	$15,939,000	$5,312,000	$43,591,000	$14,680,000
Oilfield services	3,244,000	2,533,000	8,333,000	7,585,000
	19,183,000	7,845,000	51,924,000	22,265,000
Corporate	83,000	156,000	353,000	474,000
Intersegment eliminations	(1,037,000)	(569,000)	(1,998,000)	(1,182,000)
Total Revenues	$18,229,000	$7,432,000	$50,279,000	$21,557,000
Operating Earnings				
Oil & gas (including derivative effects)	$10,092,000	$1,843,000	$26,623,000	$ 4,245,000
Oilfield services	807,000	79,000	1,178,000	658,000
	10,899,000	1,922,000	27,801,000	4,903,000
Corporate	(817,000)	(678,000)	(2,300,000)	(2,106,000)
Intersegment eliminations	(244,000)	(18,000)	(376,000)	(163,000)
Income Before Income Taxes and Change in Accounting Principle	$ 9,838,000	$1,226,000	$25,125,000	$ 2,634,000

7. RECENT ACCOUNTING PRONOUNCEMENTS

In September 2002, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 148, Accounting for Stock-Based Compensation Transition and Disclosure an amendment of FASB Statement No. 123, effective for the fiscal years beginning after December 31, 2002. SFAS No. 148 amends SFAS No. 123, Accounting for Stock-Based Compensation, to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. We continue to follow the intrinsic value method prescribed by APB 25 in accounting for stock options, recognizing no compensation expense for options granted at or above market price. We adopted the provisions of SFAS No. 148 effective for the fiscal year ended December 31, 2002 and have complied with the amended disclosure requirements.

In April 2003, the FASB issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities to amend and clarify financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities. The changes in this statement require that contracts with comparable characteristics be accounted for similarly to achieve more consistent reporting of contracts as either derivative or hybrid instruments. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003 and will be applied prospectively. We do not anticipate any significant impact on our financial position or results of operations upon adoption.

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In May 2003, the FASB issued SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity to improve the accounting for certain financial instruments that, under previous guidance, issuers could account for as equity. SFAS No. 150 requires that those instruments be classified as liabilities in statements of financial position. SFAS No. 150 does not apply to features embedded in a financial instrument that is not a derivative in its entirety. In addition to its requirements for the classification and measurement of financial instruments within its scope, SFAS No. 150 also requires disclosures about alternative ways of settling the instruments and the capital structure of entities, all of whose shares are mandatorily redeemable. Most of the guidance in Statement 150 is effective for all financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. As we have no such financial instruments, we do not anticipate any impact on our financial position or results of operations upon adoption.

The FASB is currently engaged in discussions regarding the application of certain provisions of SFAS No. 141, Business Combinations, and SFAS No. 142, Goodwill and Other Intangible Assets, to companies in the extractive industries, including oil and gas companies. The FASB is considering whether the provisions of SFAS No. 141 and SFAS No. 142 require registrants to classify costs associated with mineral rights, including both proved and unproved lease acquisition costs, as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, Prima has included oil and gas lease acquisition costs as a component of oil and gas properties. In the event the FASB determines that costs associated with mineral rights are required to be classified as intangible assets, a portion of our oil and gas property costs incurred since the June 30, 2001 effective date of SFAS Nos. 141 and 142 would be separately classified on our balance sheets as intangible assets. However, our results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with full cost accounting rules.

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

The following discussion is intended to assist in understanding Prima s financial position at September 30, 2003, its results of operations for the three- and nine- month periods ended September 30, 2003 and September 30, 2002, and our assessments of Prima s liquidity and capital resources. For a summary of our critical accounting policies and estimates, please refer to our Annual Report on Form 10-K, page 30, for the year ended December 31, 2002.

Liquidity and Capital Resources

Historically, Prima s principal sources of liquidity have been the internal generation of cash flow from operations, proceeds from occasional asset sales, and existing net working capital. Additional potential sources of capital include borrowings and issuances of common stock or other securities. Our revenues and cash flows are substantially derived from oil and gas sales, which are dependent upon oil and gas production volumes and sales prices.

Prima s net working capital increased from $35,954,000 at the end of 2002 to $53,081,000 at September 30, 2003. Our current assets at the end of September 2003 included cash equivalents and short-term investments totaling $51,875,000, compared to $38,007,000 at the end of 2002, and we were free of long-term debt at both dates. This strong financial condition provides Prima with considerable flexibility in responding to opportunities and scheduling capital investments to take advantage of market conditions.

Cash flow from operations before changes in operating assets and liabilities totaled $34,423,000 in the first nine months of 2003, compared to $14,404,000 in the first nine months of 2002. (This is a non-GAAP financial measure derived from net cash provided by operating activities; see Reconciliation of Non-GAAP Financial Measure in table below.) We also received cash proceeds totaling $1,664,000 from the sale of certain oil and gas properties. During the first nine months of 2003, our investments in property and equipment totaled $19,080,000, including $18,287,000 related to oil and gas properties. In addition, we expended $793,000 for other property and equipment, and $2,111,000 for the purchase of approximately 112,000 shares of treasury stock at an average cost of $18.87 per share. Approximately 291,000 additional shares of Prima s common stock may be repurchased under an existing authorization from our Board of Directors.

We have entered into various operating leases for office space and gas compression equipment. As of September 30, 2003, our contractual obligations under these leases were as follows: within one year, $335,000; from one to three years, $634,000; and after three years, $449,000.

Prima s capital expenditures for all of 2003 are currently expected to aggregate between $29 million and $31 million, including $10 million to $12 million in the fourth quarter. We also estimate that our net oil and gas production in the current quarter will total approximately 4.0 Bcfe, bringing Prima s total for 2003 to approximately 15.1 Bcfe. This target represents approximately a 43% increase over total net production reported in 2002.

We expect to fund planned current period exploration, development, and exploitation operations, the expansion of our service companies, and any repurchases of common stock with cash provided by operating activities and existing working capital. We also regularly review opportunities for acquisition of assets or companies related to the oil and gas industry that could expand or enhance our existing business. If a sufficiently large transaction is consummated, it could involve the incurrence of debt or issuance of equity securities.

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The remainder of this section provides additional information relating to our recent and planned near-term investment activities.

Prima s $18,287,000 of investments in oil and gas properties during the first nine months of 2003 included $17,590,000 of costs incurred on wells and related property development and $697,000 for undeveloped acreage. Operations included drilling a total of 97 (68.9 net) wells, including 21 (20.2 net) wells in the Denver Basin, 63 (47.6 net) CBM wells in the Powder River Basin, 12 (1.0 net) wells in the Wind River Basin, and one (0.1 net) well in the Washakie Basin. Other activities included re-fracturing 28 (27.1 net) wells in the Denver Basin, completing two Denver Basin wells drilled in late 2002, and developing infrastructure facilities in the CBM area. All drilling and recompletion operations have been apparently successful, with wells placed on production, restored to production, or awaiting hook up.

Activities during the recent quarter included drilling and completing 23 (22.2 net) wells in the Porcupine-Tuit CBM project area. These, and four wells previously drilled in the area, were hooked up between late September and mid-October. Gross production at Porcupine-Tuit has increased from approximately 21,000 Mcfd in September 2003, prior to tie in of new wells, to a recent rate in excess of 28,000 Mcfd. Prima owns net revenue interests in the 85 wells at Porcupine-Tuit averaging approximately 78%. One additional well is scheduled to be drilled and hooked up at Porcupine-Tuit in the current quarter.

Seventeen (11.9 net) additional Powder River Basin CBM wells were drilled during the third quarter of 2003, targeting multiple coals in Prima s Kingsbury, North Shell Draw and Cedar Draw project areas. Prima is currently evaluating alternative proposals for installation of gas gathering and compression facilities in these areas, and anticipates hooking up the recently drilled wells, along with 104 previously drilled wells and additional planned wells, beginning in the first quarter of 2004. This area encompasses our pilot project in the Kingsbury area, where 16 wells were placed on pump approximately ten months ago to begin de-watering and evaluating the deeper Cook and Wall coals. These wells, particularly the eight completed in the Wall coal, continue to produce water at rates indicating good permeability, and three of the Wall-coal wells began producing small amounts of gas in September or October. Significant future activity is planned in the adjoining Kingsbury, Cedar Draw, and North Shell Draw areas, to develop multiple coals found at depths ranging from approximately 600 feet to 2,000 feet. Subject to being able to obtain regulatory approvals, among other factors, activities planned for the current quarter in these project areas include drilling 15 to 20 CBM wells and deepening 16 previously drilled CBM wells to lower coals.

Prima drilled 14 (13.2 net) wells and recompleted nine (9.0 net) wells in the Denver Basin in the third quarter of 2003. Planned fourth quarter activities in this area include drilling approximately ten wells and recompleting approximately 14 wells. At Cave Gulch, in the Wind River Basin, Prima participated in drilling five (0.3 net) wells and recompleting one (0.1 net) well in the third quarter, and we anticipate participating in drilling approximately four wells in the current quarter. Prima also participated, with a 12.5% non-operated working interest, in drilling the Vermillion Federal #27-6 exploratory well in the Washakie Basin in Wyoming. The well, which was drilled to a depth of 10,890 feet and logged apparent pay in multiple sands, is currently being completed, after which further development plans for the 5,300-acre block will be considered.

During the recent quarter, Prima also initiated completion and testing of the Ferron sand in the Scofield-Thorpe #22-41 well on the Coyote Flats prospect, in Carbon County, Utah. This 100%-owned well was drilled in late 2002 to test the Emery coals and Ferron sand, but was temporarily suspended after production casing was set. We are currently testing the Ferron sandstone reservoir at depths between 5,995-6,055 feet. The Ferron sandstone has been productive at Clear Creek Field, located eight miles southwest of the Scofield-Thorpe #22-41 well, and is currently productive at Gordon Creek Field, located ten miles southeast of the well. Prima is currently conducting a 30-day flow test on the well, which will be followed by a 7-day pressure buildup test. During the flow test, gas rates of 900 Mcfd and water rates of 150 bpd have been measured, with gradually increasing gas rates and decreasing water rates. The objective of the pressure buildup test will be to determine well performance parameters that can be used to assess the economics of installing a natural gas pipeline to this location and drilling additional Ferron sandstone wells on the Coyote Flats acreage. A multi-well pilot program to further evaluate Emery coal potential is also anticipated to get underway in 2004. Prima controls approximately 75,000 gross (72,000 net) undeveloped acres within the Coyote Flats Prospect area.

On the Merna Prospect, located on the Merna anticlinal structure in the northern Green River Basin in Sublette County, Wyoming, we are currently participating in the Sage Flat Federal #17-20 well. Prima holds a 6.3% working interest before payout and a 10.9% working interest after payout in this well, which will target the over-pressured Lance Formation at a depth of approximately 13,000 feet. In addition, Prima owns an average 35% working interest in 74,000 gross acres in the greater Merna area. The Sage Flat Federal #17-20 well is located three miles north of the Miller Federal #7-4 well that was drilled during the second half of 2002, and which exhibited strong gas shows at high pressure while drilling but which was subsequently completed for only modest gas rates.

Prima recently exchanged acreage in the Powder River Basin CBM play with another operator. The acreage that we traded, primarily in the Deadman Draw area, had been attributed approximately 8 Bcf of proved reserves. The acreage that we received, in our Fortification Creek and Kingsbury project areas, does not currently have attributed proved reserves but has greater estimated potential reserves and higher projected value to Prima. The trade strengthens to 4,900 gross (4,500 net) acres our land position at Fortification Creek, a project area with multiple deep thick coal targets, located ten miles west of North Shell Draw.

As previously reported, our planned 2003 activities in the Powder River Basin CBM play were weighted toward the second half of the year. One factor influencing that schedule was the timing of a record of decision (ROD) issued by the Bureau of Land Management (BLM), to finalize an environmental impact statement (EIS) for the area. The ROD was issued on April 30, 2003 and is expected, ultimately, to significantly improve access to federal lands in the Powder River Basin for CBM development. However, as anticipated, various challenges to the ROD have been filed in federal courts and there may be delays in its full implementation pending resolution of these challenges. While some of Prima s planned activities for the balance of 2003 may be affected by the status of the BLM s implementation of the EIS, drilling activity may also be dependent on other factors. These include the timing and conditions of approvals required for certain water management plans, completion of agreements with various surface owners, and conclusion of negotiations with certain working interest owners regarding potential acreage swaps.

Reconciliation of Non-GAAP Financial Measure

Cash flow from operations before changes in operating assets and liabilities is presented because of its acceptance as an indicator of the ability of an oil and gas exploration and production company to internally fund exploration and development activities. This measure should not be considered as an alternative to net cash provided by operating activities as defined by generally accepted accounting principles. A reconciliation of cash flow from operations before changes in operating assets and liabilities to net cash provided by operating activities is shown below:

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	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
Net cash provided by operating activities	$32,370,000	$13,326,000
Net changes in operating assets and liabilities	2,053,000	1,078,000
Cash flow from operations before changes in operating Assets and liabilities	$34,423,000	$14,404,000

Results of Operations

As noted, our primary source of revenues is the sale of oil and natural gas production. Because of significant fluctuations in oil and gas prices and variances in production volumes, our operating results for any period are not necessarily indicative of future operating results. Oil and gas prices have historically been volatile and are likely to continue to be volatile. Prices are affected by, among other things, market supply and demand factors, market uncertainty, and actions of the United States and foreign governments and international cartels. These factors are beyond our control. Our revenues, cash flows, earnings and operations are adversely affected when oil and gas prices decline. Natural gas has typically represented more than three-quarters of our total oil and gas production mix. Gas prices reached record high levels in early 2001, with NYMEX gas trading near $10.00 per MMBtu in January 2001. Prices subsequently declined significantly, reaching a low of $1.88 per MMBtu for NYMEX gas in October 2002, after which a sharp recovery brought NYMEX gas prices to near-record levels in March 2003. Prices began to weaken moderately in the third quarter, but NYMEX gas prices currently remain relatively favorable, with recent trading levels for near-term deliveries between $4.50 and $5.50 per MMBtu.

In addition to factors affecting global or national markets for oil and natural gas, our business is subject to regional influences on gas markets. Gas production in the Rocky Mountain area, where Prima s producing properties are located, generally exceeds regional consumption needs and the surplus is transported via pipelines to other markets. Rocky Mountain gas has typically sold for a lower price than gas produced in the Gulf Coast region or in areas closer to major consumption markets that rely on gas delivered from outside the region. The size of the discount has varied widely based on seasonal factors, structural factors, and other supply and demand influences. From 1991 through 2002, Colorado Interstate Gas (CIG) index prices averaged approximately $0.57 per MMBtu less than the average index prices for gas at Henry Hub (the delivery point for NYMEX contracts), but the amount of this discount ranged on an annual basis between $0.26 (1999) and $1.29 (2002). Monthly variances in index prices during this period ranged between a premium of $0.11 (January 1993) and a discount of $2.44 (October 2002).

Basis differentials widened considerably beginning in May 2002, as gas supply in the region began to outstrip the aggregate of regional demand and available pipeline capacity to export gas to other markets. Rocky Mountain gas prices rose during the winter of 2002-2003, but basis differentials remained unusually wide, as prices in other regions increased as much or more. In May 2003, the Kern River pipeline expansion went in service, providing a significant increase in capacity to export Rocky Mountain gas, and the basis differential has narrowed each month since April. The average differentials between Henry Hub and CIG indices in the last seven fiscal quarters, beginning with the first quarter of 2002 and ending with the third quarter of 2003, have been as follows: $0.45, $1.22, $1.98, $1.50, $2.82, $1.51, and $0.81. Reflecting movements in both national gas markets and in the Rocky Mountain basis differential, the monthly index prices for CIG, which is the principal benchmark for virtually all of Prima s gas production, averaged as follows per MMBtu in the last seven fiscal quarters, beginning with the first

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quarter of 2002: $1.94, $2.15, $1.29, $2.50, $3.78, $3.98, and $4.29. In October 2003, the basis differential narrowed further to $0.51 and the CIG index was $4.01 per MMBtu.

These price movements significantly impact our operating results, as described below for the periods reported. We cannot accurately predict future oil and natural gas prices, but historically oil and gas supply and demand have responded to changes in price levels to correct for short-lived extreme levels of high or low prices.

The following table, which presents selected operating data, is followed by discussion of our results of operations for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Production:				
Natural gas (Mcf)	3,272,000	2,002,000	9,378,000	5,834,000
Oil (barrels)	97,000	96,000	285,000	279,000
Total natural gas equivalents (Mcfe)	3,852,000	2,577,000	11,088,000	7,507,000
Revenue:				
Natural gas sales	$12,298,000	$3,013,000	$32,629,000	$10,799,000
Oil sales	$ 2,961,000	$2,442,000	$ 8,976,000	$ 6,661,000
Total oil and gas sales	$15,259,000	$5,455,000	$41,605,000	$17,460,000
Average sales price, including hedging effects:				
Natural gas (per Mcf)	$ 3.76	$ 1.50	$ 3.48	$ 1.85
Oil (per barrel)	$ 30.64	$ 25.50	$ 31.49	$ 23.90
Total natural gas equivalents (per Mcfe)	$ 3.96	$ 2.12	$ 3.75	$ 2.33
Expenses (per Mcfe):				
Depletion of oil & gas properties	$ 0.93	$ 0.90	$ 0.93	$ 0.90
Lease operating expense	$ 0.21	$ 0.27	$ 0.23	$ 0.30
Ad valorem and production taxes	$ 0.37	$ 0.17	$ 0.36	$ 0.19
General and administrative expense	$ 0.22	$ 0.30	$ 0.22	$ 0.32

Quarters Ended September 30, 2003 and 2002

For the quarter ended September 30, 2003, Prima reported net income of $6,593,000, or $0.50 per diluted share. These operating results compare to third quarter 2002 net income of $1,026,000, or $0.08 per diluted share. Total revenues increased by $10,797,000, from $7,432,000 in the third quarter of 2002 to $18,229,000 in the latest quarter. Total expenses, other than income taxes, increased by $2,185,000, from $6,206,000 in the third quarter of 2002 to $8,391,000 in the recent quarter. These year-over-year changes represent an overall 145% increase in revenues and a 35% increase in expenses.

Oil and gas sales totaled $15,259,000 in the third quarter of 2003, compared to $5,455,000 in the prior-year period, for a 180% increase. The improvement was attributable to the combined effects of a 49% year-over-year increase in production volumes and an 87% increase in average realized oil and gas prices. During the recent quarter, natural gas accounted for 85% of Prima s total production and 81% of its oil and gas sales, compared to 78% and 55%, respectively, in the third quarter of 2002.

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Prima s natural gas production increased by 63%, from 2,002,000 Mcf in the third quarter last year to 3,272,000 Mcf in the latest quarter. Oil production totaled approximately 97,000 barrels in the third quarter of 2003, compared to 96,000 barrels in the same quarter of 2002, for an increase of 1%. On an equivalent unit basis, production expanded from 2,577,000 Mcfe in the third quarter of 2002 to 3,852,000 Mcfe in the recent quarter. This increase was due to Powder River Basin CBM operations, which generated net gas production of 1,635,000 Mcf in the third quarter of 2003, compared to 308,000 Mcf in the third quarter of 2002. CBM production is primarily attributable to the Porcupine-Tuit property, which began producing during the third quarter of 2002.

Average sales prices received for natural gas production were $3.76 per Mcf in the third quarter of 2003 and $1.50 per Mcf in the 2002 quarter, representing a year-over-year increase of $2.26 per Mcf, or 151%. Though significantly improved year-over-year, Prima s average price per Mcfe did not increase as much as the CIG benchmark index, due to a greater component in 2003 of Powder River Basin CBM gas, which has higher transportation costs and lower Btu content than gas produced from other properties. Average prices received per barrel of oil were $30.64 in the recent quarter and $25.50 in the same period last year, for an increase of $5.14 per barrel or 20%. On an energy equivalent basis, the average price received was $3.96 per Mcfe in the latest quarter compared to $2.12 per Mcfe in the prior year period. Hedging gains included in oil and gas revenues for the third quarter of 2003 increased average price realizations by $0.10 per Mcf of natural gas, $0.12 per barrel and $0.09 per Mcfe. Hedging losses included in oil and gas revenues for the third quarter of 2002 decreased average price realizations by $2.66 per barrel of oil and $0.10 per Mcfe.

Third quarter 2003 revenues included $680,000 of net gains recognized on ineffective hedges, which consisted of contracts for forward sales of NYMEX natural gas, which don t qualify as effective cash flow hedges without corresponding basis-differential hedges. In the third quarter of the prior year, we reported net losses of $143,000 on similar transactions.

Depletion expense reported for the third quarter of 2003 was $3,599,000, including $36,000 of accretion expense for estimated future asset retirement obligations, in accordance with SFAS 143. The rate of $0.93 per Mcfe of oil and gas production in 2003 compares to $0.90 per Mcfe in 2002. Depreciation of other fixed assets, which include service equipment, office furniture and equipment, and buildings, totaled $236,000 and $202,000 for the third quarters of 2003 and 2002, respectively.

Lease operating expenses (LOE) totaled $805,000 for the three months ended September 30, 2003 compared to $685,000 for the three months ended September 30, 2002, an increase of $120,000 or 18%. Additional costs were largely attributable to new production from CBM wells. LOE decreased per unit-of-production, from $0.27 per Mcfe in the third quarter of 2002 to $0.21 per Mcfe in recent quarter. The lower LOE per unit primarily reflected the expanded production base in Wyoming over which field office expenses have been spread since bringing the Porcupine-Tuit property on-line. Ad valorem and other production taxes totaled $1,444,000 and $448,000 for the same periods, an increase of $996,000. Production taxes averaged $0.37 and $0.17 per Mcfe in the 2003 and 2002 quarters, respectively, reflecting both higher product prices in 2003 and an increased portion of sales attributable to properties in Wyoming, where severance tax rates are higher than in Colorado. Total lifting costs (LOE plus ad valorem and production taxes) were 15% of oil and gas revenues and $0.58 per Mcfe during the third quarter of 2003, compared to 21% and $0.44 per Mcfe in the same period in 2002.

Oilfield services include the operations of Action Oilfield Services, Inc. (Colorado) and Action Energy Services (Wyoming), wholly-owned subsidiaries. Related revenues include well servicing fees from completion and swab rigs, CBM drilling rigs, trucking, water hauling, equipment rentals, and other related activities. Services are provided to both Prima and unaffiliated third parties, but intercompany billings and related costs are eliminated in consolidation. Oilfield service revenues from third parties totaled $2,207,000 in

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the quarter ended September 30, 2003 compared to $1,964,000 in the quarter ended September 30, 2002, for an increase of $243,000, or 12%. Costs of oilfield services provided to third parties were $1,470,000 in third quarter of 2003 compared to $1,779,000 in same quarter last year, for a decrease of $309,000, or 17%. Service fees and costs associated with Prima-owned property interests represented 32% of the service companies activities in 2003 compared to 22% in 2002. The 12% year-over-year increase in reported revenues, despite the increased portion of work conducted on behalf of Prima, reflected higher utilization and billing rates in response to greater demand. The 17% reduction in costs reflected the increased amount eliminated in consolidation, due to the greater portion of work performed for Prima, and a change in the mix of activities conducted for Prima.

General and administrative expenses (G&A), net of third party reimbursements and amounts capitalized, were $837,000 for the three months ended September 30, 2003 compared to $772,000 for the three months ended September 30, 2002. The $65,000 increase in net G&A was primarily due to higher payroll taxes attributable to exercises of employee stock options. Capitalized G&A totaled approximately $486,000 in both quarters.

Prima s income tax provision was 33% of pre-tax income in the recent quarter, compared to 17% in the prior year s third quarter. The higher effective rate in the current year was due to permanent differences that did not increase proportionately with pre-tax income and the cessation of Section 29 tax credits at the end of 2002.

Nine Months Ended September 30, 2003 and 2002

For the nine months ended September 30, 2003, Prima reported net income of $17,238,000, or $1.32 per diluted share, compared to net income of $2,294,000, or $0.17 per diluted share, for the nine months ended September 30, 2002. Net income for the first nine months of 2003 included an adjustment for the cumulative effect of a change in accounting principle, in conjunction with adoption of Statement of Financial Accounting Standards No. 143, which relates to accounting for asset retirement obligations. Adoption of SFAS 143 resulted in a non-cash, after-tax credit of $403,000 or $0.03 per diluted share, reflecting the net historical effects of providing for estimated future costs for abandonment of oil and gas properties and the impact on depletion expense of incorporating estimated equipment salvage values.

Total revenues increased by $28,722,000, from $21,557,000 in the first nine months of 2002 to $50,279,000 in the first nine months of 2003. Total expenses, other than income taxes, increased by $6,231,000, from $18,923,000 in the first nine months of 2002 to $25,154,000 in the recent period. These year-over-year changes represent an overall 133% increase in revenues and a 33% increase in expenses.

Revenues reported for the first nine months of 2003 included $1,986,000 of net gains recognized on ineffective hedges, comprised of forward sales of NYMEX natural gas. In the same period of the prior year, Prima reported net losses of $2,780,000 on similar contracts, as mark-to-market gains recorded on open positions at the end of 2001 were partially reversed upon subsequent improvement in gas prices.

Oil and gas sales totaled $41,605,000 during the 2003 period, compared to $17,460,000 in the 2002 period, for an increase of 138%. The improvement was attributable to the combined effects of a 48% year-over-year increase in production volumes and a 61% increase in average prices realized per equivalent unit of oil and gas production.

Prima s net natural gas production during the first nine months of 2003 and 2002 totaled 9,378,000 Mcf and 5,834,000 Mcf, respectively, reflecting an increase of 3,544,000 Mcf, or 61%. This improvement was attributable to significant year over year increases in contributions from Powder River Basin CBM properties. Net oil production was 285,000 barrels and 279,000 barrels during the

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same nine-month periods, representing a year-over-year increase of 6,000 barrels or 2%. On an equivalent unit basis, Prima s production increased from 7,507,000 Mcfe in the first nine months of 2002 to 11,088,000 Mcfe during the same period in 2003.

The average price received for our natural gas production during the nine months ended September 30, 2003 was $3.48 per Mcf, compared to $1.85 per Mcf in the nine months ended September 30, 2002, representing an increase of $1.63 or 88%. Average prices received for oil during the same periods were $31.49 and $23.90 per barrel, respectively, for a year-over-year increase of $7.59 or 32%. On an Mcf equivalent basis, the average price received for our production was $3.75 for the nine months ended September 30, 2003 compared to $2.33 in the nine months ended September 30, 2002. Gains and losses on hedges included in oil and gas revenues for the first nine months of 2003 had the effect of decreasing the average price realized per Mcf of natural gas by $0.01, increasing the average price realized per barrel of oil by $0.18, with no net impact on the price realized per Mcfe. Hedging losses included in oil and gas revenues for the first nine months of 2002 decreased average price realizations by $1.48 per barrel of oil and $0.05 per Mcfe.

Depletion expense for oil and gas properties was $10,358,000 during the first nine months of 2003, including $101,000 of accretion expense for estimated future asset retirement obligations. The rate of $0.93 per Mcfe of oil and gas production in 2003 compares to $0.90 per Mcfe in 2002. Depreciation of other fixed assets totaled $798,000 and $846,000 in the first nine months of 2003 and 2002, respectively.

Lease operating expenses declined from an average $0.30 per Mcfe in the nine months ended September 30, 2002 to an average $0.23 per Mcfe in the nine months ended September 30, 2003, due primarily to the impact of production at Porcupine-Tuit. Production taxes were $0.36 and $0.19 per Mcfe in the 2003 and 2002 nine-month periods, respectively, reflecting higher product prices in 2003 and an increased proportion of sales derived from Wyoming. Total lifting costs were 16% of oil and gas revenues and $0.60 per Mcfe for the first nine months of 2003, compared to 21% and $0.49 per Mcfe for the same 2002 period.

Oilfield service revenues from third parties declined by 1%, from $6,403,000 in the first nine months of 2002 to $6,335,000 during the latest nine-month period. Related oilfield service costs were $4,917,000 in the nine months ended September 30, 2003, compared to $5,258,000 for the same period of 2002, a decrease of $341,000 or 6%. For the nine months ended September 30, 2003, 24% of fees billed by the service companies were for Prima-owned property interests, compared to 16% for the nine months ended September 30, 2002. An overall increase in billings was approximately offset by greater amounts related to Prima wells. Reported costs declined as a result of the increased portion eliminated in consolidation.

General and administrative expenses, net of third party reimbursements and amounts capitalized, totaled $2,471,000 for the nine months ended September 30, 2003 compared to $2,388,000 for the nine months ended September 30, 2002. Higher personnel costs were partially offset by increased reimbursements from third parties.

Prima s income tax provision was 33% of pre-tax income in the recent nine-month period, compared to 13% in the prior year s comparable period, due to permanent differences that did not increase proportionately with pre-tax income and the cessation of Section 29 tax credits at the end of 2002.

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Recent Accounting Pronouncements

In September 2002, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 148, Accounting for Stock-Based Compensation Transition and Disclosure an amendment of FASB Statement No. 123, effective for the fiscal years beginning after December 31, 2002. SFAS No. 148 amends SFAS No. 123, Accounting for Stock-Based Compensation, to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. We continue to follow the intrinsic value method prescribed by APB 25 in accounting for stock options, recognizing no compensation expense for options granted at or above market price. We adopted the provisions of SFAS No. 148 effective for the fiscal year ended December 31, 2002 and have complied with the amended disclosure requirements.

In April 2003, the FASB issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities to amend and clarify financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities. The changes in this statement require that contracts with comparable characteristics be accounted for similarly to achieve more consistent reporting of contracts as either derivative or hybrid instruments. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003 and will be applied prospectively. We do not anticipate any significant impact on our financial position or results of operations upon adoption.

In May 2003, the FASB issued SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity to improve the accounting for certain financial instruments that, under previous guidance, issuers could account for as equity. SFAS No. 150 requires that those instruments be classified as liabilities in statements of financial position. SFAS No. 150 does not apply to features embedded in a financial instrument that is not a derivative in its entirety. In addition to its requirements for the classification and measurement of financial instruments within its scope, SFAS No. 150 also requires disclosures about alternative ways of settling the instruments and the capital structure of entities, all of whose shares are mandatorily redeemable. Most of the guidance in Statement 150 is effective for all financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. As we have no such financial instruments, we do not anticipate any impact on our financial position or results of operations upon adoption.

The FASB is currently engaged in discussions regarding the application of certain provisions of SFAS No. 141, Business Combinations, and SFAS No. 142, Goodwill and Other Intangible Assets, to companies in the extractive industries, including oil and gas companies. The FASB is considering whether the provisions of SFAS No. 141 and SFAS No.142 require registrants to classify costs associated with mineral rights, including both proved and unproved lease acquisition costs, as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, Prima has included oil and gas lease acquisition costs as a component of oil and gas properties. In the event the FASB determines that costs associated with mineral rights are required to be classified as intangible assets, a portion of our oil and gas property costs incurred since the June 30, 2001 effective date of SFAS Nos. 141 and 142 would be separately classified on our balance sheets as intangible assets. However, our results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with full cost accounting rules.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our primary market risks relate to changes in prices received on sales of natural gas and oil production. We periodically enter into derivatives contracts to mitigate a portion of this commodity price risk. Such derivatives consist of commodity futures or price swaps (agreements with counterparties to exchange floating prices for fixed prices), and options on such futures or price swaps. These instruments reduce our exposure to decreases in gas and oil prices, or increases in differentials between NYMEX and Rocky Mountain gas prices, but they also generally limit the benefits realized from increases in prices or narrowing of basis differentials. To the extent that we hedge only a portion of our exposure to changes in prices, we are able to benefit from increases in gas and oil prices or improvements in basis differentials, but we remain exposed to market risk on the portion of our production not covered by such derivatives. Prima also retains risks related to the ineffective portion of its derivatives instruments, when applicable.

We have entered into derivatives contracts that are intended to offset risks associated with downward price movements in benchmark NYMEX oil and gas prices, and basis swaps to offset risks of increases in the differential between NYMEX and Rocky Mountain gas prices. These derivatives positions represent cash flow hedges that are determined to be qualifying or non-qualifying for hedge accounting treatment in accordance with the provisions of SFAS 133. See Derivatives Transactions in Notes to Unaudited Consolidated Financial Statements for additional information with respect to our derivatives and related accounting policies.

Personnel who have appropriate skills, experience and supervision execute all derivatives transactions. The personnel involved in these activities must follow prescribed trading limits and parameters that are regularly reviewed by Prima s Chief Executive Officer. Prima s Chief Executive Officer approves all derivatives transactions before being entered into and significant transactions are reviewed by Prima s Board of Directors. We utilize only conventional derivatives instruments and attempt to manage credit risk by entering into derivatives contracts only with financial institutions that are believed to be reputable and which carry an investment grade rating.

Prima realized net settlement gains totaling $213,000 on derivatives positions closed out during October 2003. At the close of business on October 31, 2003, open derivatives instruments (all relating to crude oil) showed net unrealized gains aggregating $76,000, as follows:

Time Period	Market Index	Total Volumes (Bbls)	Contract Price	Unrealized Gains
December 2003	NYMEX	15,000	$30.64	$23,000
January - March 2004	NYMEX	45,000	29.75	53,000
Total Unrealized Gains				$76,000

Certain additional information regarding our market risks is provided below. Investors and other users are cautioned to avoid simplistic use of these disclosures. Users should realize that the actual impact of future commodity price movements would likely differ from the amounts disclosed below due to ongoing changes in risk exposure levels and concurrent adjustments to positions. It is not possible to accurately predict future movements in natural gas and oil prices.

During the first nine months of 2003 Prima sold 285,000 barrels of oil. A hypothetical decrease of $3.13 per barrel (10% of average prices for the period excluding hedging transactions) would have decreased our production revenues by $892,000 for that period. Prima sold 9,378,000 Mcf of natural gas during the first nine months of 2003. A hypothetical decrease of $0.35 per Mcf (10% of average prices for the period excluding hedging transactions) would have decreased our production revenues by $3,282,000 for that period.

ITEM 4. CONTROLS AND PROCEDURES

Prima s principal executive officer and principal financial officer evaluated the effectiveness of Prima s disclosure controls and procedures, as such term is defined in Rule 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended, as of the end of the period covered by this report (the Evaluation Date). Based upon their evaluation, the principal executive officer and principal financial officer concluded that, as of the Evaluation Date, Prima s disclosure controls and procedures were effective. During Prima s most recent quarter, there were no significant changes in Prima s internal control over financial reporting that have materially affected, or are reasonably likely to materially affect Prima s internal control over financial reporting.

CAUTIONARY STATEMENT FOR PURPOSES OF THE SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

Management s Discussion and Analysis of Financial Condition and Results of Operations included in Item 2 of this Report contains forward-looking statements, which are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. These statements include, without limitation, statements relating to liquidity, financing of operations, capital expenditures budget (both the amount and the source of funds), continued volatility of oil and natural gas prices, future drilling plans and other such matters. The words anticipate, expect, plan, target, estimate or project and similar expressions identify forward-looking statements. Such statements are based certain assumptions and analyses made by Prima s management in light of their experience and perceptions of historical trends, current conditions, expected future developments and other factors that are believed to be appropriate in the circumstances. Prima does not undertake to update, revise or correct any of the forward-looking information. Factors that could cause actual results to differ materially from the expectations expressed in the forward-looking statements include, but are not limited to, the following: industry conditions; volatility of oil and natural gas prices; hedging activities; operational risks (such as blowouts, fires and loss of production); insurance coverage limitations; potential liabilities, delays and associated costs imposed by government regulation (including environmental regulation); the need to develop and replace Prima s oil and natural gas reserves; the substantial capital expenditures required to fund operations; risks related to exploration and developmental drilling; and uncertainties about oil and natural gas reserve estimates. For a more complete explanation of these various factors, see Cautionary Statement for the Purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995 included in Prima s Annual Report on Form 10-K for the year ended December 31, 2002, beginning on page 23.

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PART II. OTHER INFORMATION

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) Exhibits

Exhibit No.	Document
3.1	Certificate of Incorporation of Prima Energy Corporation, Delaware, as filed August 18, 1988. (Incorporated by reference to Registration of Securities of Certain Successor Issuers on Form 8-B dated January 20, 1989.)
3.2	Certificate of Amendment of Certificate of Incorporation of Prima Energy Corporation filed May 1, 1989. (Incorporated by reference to Annual Report on Form 10-K for Prima Energy Corporation dated September 30, 1989.)
3.3	Bylaws of Prima Energy Corporation. (Incorporated by reference to Registration of Securities of Certain Successor Issuers on Form 8-B dated January 20, 1989.)
3.4	Certificate of Amendment of the Certificate of Incorporation of Prima Energy Corporation. (Incorporated by reference to Quarterly Report on Form 10-Q for Prima Energy Corporation dated September 30, 1997.)
3.5	Certificate of Amendment of the Certificate of Incorporation of Prima Energy Corporation. (Incorporated by reference to Quarterly Report on Form 10-Q for Prima Energy Corporation dated September 30, 2000.)
3.6	Certificate of Amendment of the Certificate of Incorporation of Prima Energy Corporation. (Incorporated by reference to Quarterly Report on Form 10-Q for Prima Energy Corporation dated September 30, 2001.)
4.1	Rights Agreement dated as of May 23, 2001, between Prima Energy Corporation and Computershare Trust Company, Inc., as Rights Agent, including the form of Certificate of Designation, Powers, Preferences and Rights of Series A Participating Preferred Stock dated May 29, 2001, as Exhibit A, the Form of Right Certificate, as Exhibit B, and the Summary of Rights to Purchase Preferred Shares. (Incorporated by reference to Current Report on Form 8-K for Prima Energy Corporation dated May 23, 2001.)
10.1	Prima Energy Corporation Employee Stock Ownership Plan (Incorporated by reference to Annual Report on Form 10-K for Prima Energy Corporation dated September 30, 1989.)
10.2	Prima Energy Corporation 1993 Stock Incentive Plan. (Incorporated by reference to Annual Report on Form 10-K for Prima Energy Corporation dated December 31, 1993.)
10.3	Agreement of Lease between Denver-Stellar Associates LP, Landlord and Prima Energy Corporation, Tenant, effective December 1, 2000. (Incorporated by reference to Annual Report on Form 10-K for Prima Energy Corporation dated December 31, 2000.)
10.4	Prima Energy Corporation Non-Employee Directors Stock Option Plan. (Incorporated by reference to Quarterly Report on Form 10-Q for Prima Energy Corporation dated March 31, 2002.)
10.5	Prima Energy Corporation 2001 Stock Incentive Plan. (Incorporated by reference to Quarterly Report on Form 10-Q for Prima Energy Corporation dated March 31, 2002.)
31.1	Certification of the Chief Executive Officer pursuant to § 302 of the Sarbanes-Oxley Act of 2002.

Exhibit No.	Document
31.2	Certification of the Chief Financial Officer pursuant to § 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of the Chief Executive Officer pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of the Chief Financial Officer pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002.

(b) Reports on Form 8-K

During the quarter ended September 30, 2003, the Company filed the following report on Form 8-K:

Report dated July 31, 2003, reporting second quarter 2003 financial results and providing an update of operating activities and commodity hedging transactions.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PRIMA ENERGY CORPORATION
(Registrant)

Date November 12, 2003 By /s/ Richard H. Lewis

Richard H. Lewis,
President and Chief Executive Officer

Date November 12, 2003 By /s/ Neil L. Stenbuck

Neil L. Stenbuck,
Executive Vice President and Chief Financial Officer

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