PRIMA ENERGY CORP
Form 10-Q
August 14, 2001

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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 June 30, 2001

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 [ ]

As of July 31, 2001, the Registrant had 12,682,584 shares of Common Stock, $0.015 Par Value, outstanding.

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PRIMA ENERGY CORPORATION

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PART I. FINANCIAL INFORMATION

ITEM I. FINANCIAL STATEMENTS

PRIMA ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

ASSETS

	June 30, 2001 (Unaudited)	December 31, 2000
CURRENT ASSETS		
Cash and cash equivalents	$ 19,769,000	$ 20,382,000
Available for sale securities, at market....	2,426,000	2,311,000
Receivables (net of allowance for doubtful accounts: 6/30/01, $45,000; 12/31/00,		

$44,000)	8,932,000	8,902,000
Derivatives, at fair value	2,144,000	--
Tubular goods inventory	1,721,000	1,409,000
Other	716,000	1,042,000
Total current assets	35,708,000	34,046,000
OIL AND GAS PROPERTIES, at cost, accounted for using the full cost method	129,762,000	109,652,000
Less accumulated depreciation, depletion and amortization	(47,555,000)	(43,935,000)
Oil and gas properties - net	82,207,000	65,717,000
PROPERTY AND EQUIPMENT, at cost		
Oilfield service equipment	8,592,000	7,664,000
Office furniture and equipment	805,000	729,000
Field office, shop and land	473,000	473,000
	9,870,000	8,866,000
Less accumulated depreciation	(4,442,000)	(3,986,000)
Property and equipment - net	5,428,000	4,880,000
OTHER ASSETS	1,257,000	257,000
	$ 124,600,000	$ 104,900,000

See accompanying notes to unaudited consolidated financial statements.

PRIMA ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS (CONT'D.)

LIABILITIES AND STOCKHOLDERS' EQUITY

	June 30, 2001 (Unaudited)	December 31, 2000
CURRENT LIABILITIES		
Accounts payable	$ 2,515,000	$ 3,207,000
Amounts payable to oil and gas property owners	2,524,000	2,501,000
Ad valorem and production taxes payable	3,925,000	1,857,000
Accrued and other liabilities	537,000	803,000
Deferred tax liability	626,000	--
Total current liabilities	10,127,000	8,368,000
AD VALOREM TAXES, non-current	2,056,000	3,213,000
DEFERRED TAX LIABILITY	19,034,000	13,021,000

Total liabilities	31,217,000	24,602,000
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; 12,815,873 and 12,793,373 shares issued	192,000	192,000
Additional paid-in capital	2,236,000	1,760,000
Retained earnings	92,819,000	78,472,000
Accumulated other comprehensive income (loss)	1,091,000	(126,000)
Treasury stock, 113,289 and no shares, at cost	(2,955,000)	--
Total stockholders' equity	93,383,000	80,298,000
	$ 124,600,000	$ 104,900,000

See accompanying notes to unaudited consolidated financial statements.

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PRIMA ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

	Three Months Ended June 30,		Six Months June 3
	2001	2000	2001
REVENUES			
Oil and gas sales	$ 11,909,000	$ 10,235,000	$ 28,266,000
Oilfield services	2,006,000	1,525,000	3,782,000
Interest, dividends and other	273,000	321,000	610,000
	14,188,000	12,081,000	32,658,000
EXPENSES			
Depreciation, depletion and amortization:			
Depletion of oil and gas properties	1,852,000	1,492,000	3,620,000
Depreciation of other property	296,000	285,000	578,000
Lease operating expense	651,000	619,000	1,450,000
Ad valorem and production taxes	869,000	753,000	2,293,000
Cost of oilfield services	1,379,000	1,338,000	2,513,000
General and administrative	920,000	803,000	2,008,000
	5,967,000	5,290,000	12,462,000
Income Before Income Taxes and Cumulative Effect of Change in Accounting Principle	8,221,000	6,791,000	20,196,000

Provision for Income Taxes	2,550,000	1,980,000	6,460,000
Net Income Before Cumulative Effect of Change in Accounting Principle	5,671,000	4,811,000	13,736,000
Cumulative Effect of Change in Accounting Principle	--	--	611,000
NET INCOME	$ 5,671,000	$ 4,811,000	$ 14,347,000
Basic Net Income per Share Before Cumulative Effect of Change in Accounting Principle	$ 0.45	$ 0.38	$ 1.08
Cumulative Effect of Change in Accounting Principle	--	--	0.05
BASIC NET INCOME PER SHARE	$ 0.45	$ 0.38	$ 1.13
Diluted Net Income per Share Before Cumulative Effect of Change in Accounting Principle	$ 0.43	$ 0.36	$ 1.03
Cumulative Effect of Change in Accounting Principle	--	--	0.05
DILUTED NET INCOME PER SHARE	$ 0.43	$ 0.36	$ 1.08
Weighted Average Common Shares Outstanding	12,732,542	12,715,685	12,744,977
Weighted Average Common Shares Outstanding Assuming Dilution	13,275,321	13,304,367	13,287,674

See accompanying notes to unaudited consolidated financial statements.

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PRIMA ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(UNAUDITED)

	Three Months Ended June 30,		Six Months June 3
	2001	2000	2001
Net income	$ 5,671,000	$4 811,000	$ 14,347,000
Other comprehensive income:			
Unrealized gain on derivatives	371,000	--	1,769,000

Deferred income tax expense related to unrealized gain on derivatives	(137,000)	--	(654,000)
Unrealized gain on available-for-sale securities	65,000	26,000	163,000
Deferred income tax expense related to unrealized gain on available-for-sale securities	(26,000)	(17,000)	(62,000)
Reclassification adjustment for losses included in other income	1,000	18,000	1,000
	274,000	27,000	1,217,000
COMPREHENSIVE INCOME	$ 5,945,000	$ 4,838,000	$ 15,564,000

See accompanying notes to unaudited consolidated financial statements.

PRIMA ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Six Months Ende June 30,	
	2001	
OPERATING ACTIVITIES		
Net income	$ 14,347,000	$ 8
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	4,198,000	3
Deferred income taxes	6,012,000	2
Unrealized gains from trading activities	(375,000)	
Other	102,000	
Changes in operating assets and liabilities:		
Receivables	(29,000)	
Inventory	(312,000)	
Other current assets	235,000	
Accounts payable and payables to owners	(669,000)	
Ad valorem and production taxes payable	911,000	
Accrued and other liabilities	(266,000)	(1
Net cash provided by operating activities	24,154,000	12
INVESTING ACTIVITIES		
Additions to oil and gas properties	(21,111,000)	(12
Purchases of other property	(1,252,000)	(1
Purchases of available for sale securities	(61,000)	

Proceeds from sales of oil and gas and other property	253,000	
Net cash used in investing activities	(22,171,000)	(13
FINANCING ACTIVITIES		
Treasury stock purchased	(2,955,000)	(1
Proceeds from issuance of common stock	152,000	
Other	207,000	
Net cash used in financing activities	(2,596,000)	(1
DECREASE IN CASH AND CASH EQUIVALENTS	(613,000)	(3
CASH AND CASH EQUIVALENTS, beginning of period	20,382,000	18
CASH AND CASH EQUIVALENTS, end of period	$ 19,769,000	$ 15

Supplemental schedule of noncash investing and financing activities:

Other assets acquired in exchange for undeveloped oil and gas properties	$ 1,000,000	$

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 ("Prima") is an independent oil and gas company primarily engaged in the exploration for, acquisition, development and production of, natural gas and crude oil. Through its wholly owned subsidiaries, Prima is also engaged in oil and gas property operations, oilfield services and natural gas gathering, marketing and trading. Prima's current activities are principally conducted in the Rocky Mountain region of the United States.

The financial information contained herein is unaudited but includes all adjustments (consisting of only normal recurring accruals) which, in the opinion of management, are necessary to present fairly the information set forth. The unaudited consolidated financial statements have been prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with generally accepted accounting principles. These consolidated financial statements should be read in conjunction with the Annual Report on Form 10-K of Prima Energy Corporation for the year ended December 31, 2000, including the financial statements and notes thereto.

The results for interim periods are not necessarily indicative of results to be expected for the fiscal year of the Company ending December 31, 2001. The Company believes that the six month report filed on Form 10-Q is representative of its financial position, its results of operations and its cash flows for the periods ended June 30, 2001 and 2000.

2. BASIS OF PRESENTATION

The accompanying unaudited consolidated financial statements include the accounts of Prima Energy Corporation ("Prima") and its subsidiaries, herein collectively referred to as "the Company." All significant intercompany transactions have been eliminated. Certain amounts in prior years have been reclassified to conform with the classifications at June 30, 2001.

3. RECENT ACCOUNTING PRONOUNCEMENTS

The Financial Accounting Standards Board has issued Statement of Financial Accounting Standards ("SFAS") No. 143 "Accounting for Asset Retirement Obligations."

SFAS No. 143 provides the accounting requirements for retirement obligations associated with long-lived assets. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002, and early adoption is permitted. The Company is currently assessing, but has not yet determined, the impact of SFAS No. 143 on its consolidated results of operations, cash flows or financial position.

4. DERIVATIVE ACTIVITIES

The Company's marketing and trading activities consist of marketing the Company's own production and marketing the production of others from wells operated by the Company. Crude oil and natural gas futures, options and swaps and basis swaps are used from time to time in order to hedge the price of a portion of the Company's production and to lock in the basis from NYMEX to the Rocky Mountains. This is done to mitigate the risk of fluctuating oil and natural gas prices and fluctuating basis differential, which can adversely affect operating results. These transactions have been entered into with major financial institutions, thereby minimizing credit risk. Approximately 32% of the Company's natural gas production and 9% of its oil production was hedged during the six months ended June 30, 2001, with hedging gains of $1,250,000 included in oil and gas revenues at the time the hedged volumes were sold. The Company did not hedge any of its natural gas or oil production during the first six months of 2000. At June 30, 2001, the Company had open derivative positions as follows:

Type of Derivative	Monthly Volume MMBtu) or (Barrels)	Term	Contract Fixed or Strike Price per MMBtu/Bbl	Unrealize Gains (Losses)
Natural gas futures	200,000	July-September 2001	$ 5.5500	$1,398,00
Natural gas basis swaps	240,000	July-November 2001	0.4325	717,00
Natural gas basis swaps	(60,000)	July-September 2001	1.0775	(24,00
Crude oil futures	10,000	July-August 2001	29.1950	40,00
Crude oil calls	10,000	July-August 2001	31.5000	13,00
				$2,144,00

Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"), as amended, was adopted January 1, 2001 by the Company. SFAS 133 establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities. SFAS 133 requires that an entity recognize all derivatives as either assets or liabilities in the statement of financial position and measure those instruments at fair value. If the derivative is designated as a fair value hedge, the changes in the fair value of the derivative and the hedged item will be recognized in earnings. If the derivative is designated as a cash flow hedge, changes in the fair value of the derivative will be recorded in other comprehensive income and will be recognized in the income statement when the hedged item affects earnings. SFAS 133 defines new requirements for designation and documentation of hedging relationships as well as ongoing effectiveness assessments in order to use hedge accounting. For a derivative that does not qualify as a hedge, changes in fair value will be recognized in earnings.

In connection with the adoption of SFAS 133, all derivatives within the Company were identified pursuant to SFAS 133 requirements. To the extent derivatives met the requirements of cash flow hedges, changes in the fair value of the derivatives were recognized in other comprehensive income until such time as the hedged item was or will be recognized in earnings. Hedge effectiveness is measured based on the relative changes in the fair value between the derivative contract and the hedged item over time. Any changes in fair value resulting from ineffectiveness, as defined by SFAS 133, will be recognized immediately in current earnings. To the extent derivatives are fair value hedges, changes in fair value were marked-to-market and recognized in earnings immediately.

The adoption of SFAS 133 as of January 1, 2001 resulted in the recognition of a current asset of $1,241,000, a current liability of $549,000, and net-of-tax cumulative effect adjustments reducing other comprehensive income by $129,000 and increasing net income by $611,000. The $611,000 is reflected as the cumulative effect of a change in accounting principle in the June 30, 2001 financial statements. As of June 30, 2001, the Company recorded a current asset of $2,144,000, a net of tax increase in other comprehensive income of $1,115,000, and hedging gains of $1,250,000 which are included in oil and gas revenues for the six month ended June 30, 2001.

5. COMMON STOCK

Pursuant to the provisions of the Prima Energy Corporation 1993 Stock Incentive Plan, during the second quarter of 2001, 22,500 shares of Prima's common stock were issued upon the exercise of stock options, for total proceeds of $152,000.

During the six months ended June 30, 2001, the Company repurchased 113,289 shares of its common stock as treasury stock for $2,955,000 pursuant to a stock repurchase program. The Board of Directors has authorized the repurchase of up to 5% of the Company's common stock, depending upon market conditions, the Company's financial condition, anticipated capital requirements and liquidity, among other factors. At June 30, 2001, the Company had repurchased approximately 1.0% of the shares outstanding when the authorization was approved. During the month of July 2001, the Company acquired an additional 20,000 shares of its common stock for $420,000.

During 2001, the shareholders of Prima approved an increase in the number of authorized shares of common stock from 18,000,000 shares to 35,000,000 shares.

6. EARNINGS PER SHARE

Basic net income per share is computed by dividing net income by the weighted average common shares outstanding during the period. Diluted net income per share includes 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 the increase in the number of shares issued is reduced by the number of shares which could have been repurchased by the Company with the proceeds from the exercise of the options (which were assumed to have been at the average market price of the common shares during the reporting period).

The following table reconciles the numerator and denominator used in the calculation of basic and diluted net income per share.

	Income (Numerator)	Shares (Denominator)	Per Share Amount
Quarter Ended June 30, 2001:			
Basic Net Income per Share	$5,671,000	12,732,542	$ 0.45
Effect of Stock Options	--	542,779	
Diluted Net Income per Share	$5,671,000	13,275,321	$ 0.43
Quarter Ended June 30, 2000:			
Basic Net Income per Share	$4,811,000	12,715,685	$ 0.38
Effect of Stock Options	--	588,682	
Diluted Net Income per Share	$4,811,000	13,304,367	$ 0.36

	Income (Numerator)	Shares (Denominator)	Per Share Amount
Six Months Ended June 30, 2001:			
Basic Net Income per Share	$14,347,000	12,744,977	$ 1.13
Effect of Stock Options	--	542,697	
Diluted Net Income per Share	$14,347,000	13,287,674	$ 1.08
Six Months Ended June 30, 2000:			
Basic Net Income per Share	$8,995,000	12,730,002	$ 0.71
Effect of Stock Options	--	541,576	
Diluted Net Income per Share	$8,995,000	13,271,578	$ 0.68

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

Liquidity and Capital Resources

The Company's principal internal sources of liquidity are cash flows generated from operating activities and existing net working capital. Net cash provided by operating activities for the six months ended June 30, 2001 was $24,154,000 compared to $12,545,000 for the same six month period of 2000. Net working capital at June 30, 2001 was $25,581,000 compared to $25,678,000 at December 31, 2000.

The Company invested $22,363,000 in property and equipment during the six months ended June 30, 2001, compared to $13,946,000 for the first six months of 2000. The Company expended $19,731,000 during the 2001 period for its proportionate share of the costs of drilling, completing, equipping and refracturing wells and installing gathering and compression facilities, $1,313,000 for undeveloped acreage, $67,000 for developed properties and $1,252,000 for other property and equipment. These expenditures compare to $11,632,000 for well costs, $860,000 for undeveloped acreage, $140,000 for developed properties and $1,314,000 for other equipment in the 2000 period. The Company also expended $2,955,000 for the purchase of 113,289 shares of treasury stock during the first six months of 2001 and $1,778,000 for 103,317 treasury shares during the 2000 period.

During the first six months of 2001, the Company participated in the drilling of 15 gross (14.8 net) wells and the refracturing or recompleting of 47 gross (44.0 net) wells in the Denver Basin. All of these operations have been successfully completed and the wells placed on or restored to production. Current plans are to drill an additional five to ten wells and to refrac or recomplete approximately 25 wells in this area during the remainder of 2001. During July 2001, three wells were refractured and one was recompleted.

Prima drilled 65 gross (63.5 net) CBM wells during the first half of 2001 and five gross and net wells in the current quarter to-date. Since initiating its CBM activities in 1998, Prima has drilled a total of 240 gross (237.6 net) wells in the play, and the Company plans to drill approximately 80 additional CBM wells during the balance of 2001, subject to completing certain surface use agreements and obtaining winter access to various drill-sites. This activity would increase Prima's total CBM wells drilled to approximately 320 at year-end. The Company remains on schedule to have approximately 140 CBM wells tied-in to sales lines and in various stages of production and de-watering by the end of

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August 2001, and to have a total of 200 wells tied-in by year end. Prima owns leaseholds covering 150,000 gross, 140,000 net, acres in the Powder River Basin CBM play, most of which are still undeveloped. Approximately 80% of this acreage represents federal leases that are currently subject to stringent limitations on drilling, pending completion of an ongoing environmental impact study ("EIS") for CBM drilling in the Powder River Basin, which is currently expected to be finalized in the summer of 2002.

The Company has organized its CBM acreage into 28 defined project areas. The following summary describes activities to-date for those project areas where significant operations have been conducted or where near-term activities are planned. Of the 240 CBM wells drilled by Prima to-date, 225 are located within the project areas described. The other 15 wells were drilled in various parts of the CBM play to obtain data useful for evaluation and planning, and are expected to be incorporated in future development activities. The five project areas described below on which the Company has conducted drilling operations account for approximately one quarter of Prima's total acreage in the Powder River Basin CBM play.

Stones Throw - The Company's 9,900-acre Stones Throw project area was the first selected for development, due primarily to its proximity to an existing CBM field and related infrastructure. Prima has now drilled 122 wells at Stones Throw, of which 50 have been completed in the Canyon coal, 52 have been completed in the Cook coal, and 20 have been completed in the Wall coal. Ninety-nine of these wells have been hooked up to the Company's gathering system and are now de-watering or producing. Prima has installed four screw compressors, and two reciprocating compressors at Stones Throw, establishing capacity to produce up to 10 million cubic feet of gas per day. Gross production from this field has recently been averaging approximately 6,500 Mcf of gas per day. The Company has obtained permits to drill 100 additional wells at Stones Throw, including 90 special drainage permits recently issued by the Bureau of Land Management ("BLM") for federal lands. Current plans call for drilling approximately 40 wells in the Stones Throw area during the balance of 2001.

Kingsbury - The Company has drilled 27 wells in the 8,900-acre Kingsbury project area, all of which are either producing or de-watering after having been tied into third-party gathering and compression facilities. Gross production has recently been averaging approximately 600 Mcf of gas per day. All wells drilled at Kingsbury to-date have been completed in the Lower Anderson coal, but several developable coals are present in this project area. The Company plans to submit permit applications for 117 additional well locations in this area over the next several months, including 50 on private lands and 67 on federal lands. The permits for locations on federal lands may be subject to delays due to the on-going EIS. Current plans call for the drilling of approximately 20 wells in the Kingsbury project area during the second half of the year.

North Shell Draw - Prima has drilled 36 wells targeting the Lower Anderson coal in this 7,400-acre project area. Other developable coals are also present. Access to this area for drilling and pipeline construction is limited during winter months, and no additional drilling is planned for this area in 2001. The Company plans to install, or arrange for a third party to install, a gathering system and compression at North Shell Draw by mid-2002. Seven wells are currently being prepared for production testing, to obtain data that will be utilized to configure the facilities and structure gas gathering arrangements for this area.

Porcupine-Tuit - The Company has drilled 23 Wyodak-coal wells in this 4,900-acre project area and current plans call for drilling four additional wells before year-end. The timing of drilling wells at Porcupine-Tuit has been largely dictated by lease obligations. Gathering and compression facilities

still need to be installed in order to produce these wells, and Prima plans to install, or arrange for a third party to install, such facilities by mid-2002. Drilling in the area will likely resume at that time.

Hensley - Prima has drilled and completed 17 wells in the 4,800-acre Hensley area, including eight that targeted the Lower Canyon coal, seven that were drilled to the Wall coal, and two that were drilled to the Upper Canyon coal. The Company anticipates entering into a gathering agreement with a third party for this project area by the end of the current quarter. The existing wells could be placed on line before the end of the year if an air-quality permit can be obtained to operate a gas-fired compressor. The Company also plans to apply for approximately 100 additional drilling permits on federal lands within the Hensley project area over the next several months. Issuance of such permits may be delayed due to the pending EIS.

Echeta and Wild Turkey Federal Units - The Company expects to begin drilling on the 3,800-acre Echeta federal unit within the next 60 days. Initial plans call for drilling between nine and 15 wells this year, targeting two different coals. Due to conditions imposed by the BLM relating to winter access, the Company does not expect to begin drilling on the 6,000-acre Wild Turkey federal unit until the second quarter of 2002. Previously, drilling was expected to commence at Wild Turkey in late 2001.

As noted above, all CBM wells hooked-up by Prima to-date are at Stones Throw or Kingsbury. The following table shows year-to-date well status and production for Prima's CBM operations through July 2001. Production volumes for the latest month shown are estimates. The term "hooked-up" means the well is completed and connected to a gas sales line and water handling facilities as of the end of the month. The number of producing wells shown represents all wells that produced any gas for at least one day during the month. The columns labeled "top quartile production" show the gross production of the top-producing quarter of the producing well count. The increasing trend of production rate per well reflects the early stage in the production profile of a typical CBM well. Individual well production rates during the reported period varied from less than one Mcf per day to over 250 Mcf per day. Top quartile production rates provide an indication of the variability in production rates within the total group of producing wells.

			Gross Production (Mcf)		
			All Producing Wells		Top Quar
	Total Wells Hooked-up	Total Wells Producing	Total	Avg/Well/Day	Total
January 2001	49	40	30,600	25	25,500
February 2001	64	38	37,200	35	21,700
March 2001	72	55	58,900	35	36,100
April 2001	86	69	78,600	38	51,300
May 2001	103	73	89,700	40	61,100
June 2001	123	81	109,500	45	63,600
July 2001	124	110	181,600	53	118,500

Other

Prima controls approximately 77,000 gross, 73,000 net, undeveloped acres in east-central Utah, on the Wasatch Plateau. The Company's Coyote Flats prospect is located 15 to 25 miles northwest of Price, Utah. Significant hydrocarbon production exists in the area, which is characterized by considerable structural complexity. Immediately south of Coyote Flats, at Clear Creek Field, in excess of 136 Bcf of natural gas has been produced from a Ferron sandstone structural trap. To the east of the prospect area, development is underway on the

Blackhawk coalbeds at Castlegate Field. To the southeast, Drunkards Wash Field has produced 210 Bcf of natural gas from the Ferron coalbeds. Prima's objective at Coyote Flats is to test the hydrocarbon potential of sandstone and coalbed reservoirs in the Blackhawk, Emory, Ferron and Dakota members of the middle to lower Cretaceous section. The Company has designed a drilling program to take multiple cores and drill stem tests, and data related to gas content, reservoir quality, and reservoir pressures will be gathered and evaluated. These data will be utilized to determine the future potential of the Coyote Flats prospect. The Company intends to drill the initial test well on the prospect during the second half of 2001 and anticipates either drilling an additional well or re-entering an existing well within the prospect area later this year. The timing is dependent on surface-owner approvals, rig availability and government permits. The Coyote Flats prospect is a higher-risk exploration project with no assurance that commercial production will ever be established.

Prima owns approximately 15,700 gross, 5,400 net, undeveloped acres in its Hells Half Acre prospect located in Natrona County, Wyoming. This prospect is a seismically-defined structure located approximately 10 miles southeast of the Cave Gulch Field, five miles east of the Cooper Reservoir Field, and five miles southeast of Waltman Field. The Company plans to participate in the #11-9 Miller Ranch well to be drilled on the prospect during the second half of 2001. The 12,700-foot test is designed to test the Lance-Mesaverde section, which produces at the Cave Gulch and Cooper Reservoir Fields. The Company expects to have a small working interest in the initial test well on this higher-risk project, but will have more significant exposure on surrounding lands.

This fall, Prima plans to participate in the #11-13 Echeta Road federal well, a 9,750 foot Muddy-sandstone exploratory test, located in Campbell County, Wyoming. The Company will have a 25% working interest in the initial test well. This well is located two miles southeast of Prima's Cedar Draw Field that produces from the Muddy sandstones at approximately 9,500 feet. Cedar Draw has produced 3.8 Bcf of natural gas and 94,000 barrels of oil since it was discovered in November 1997.

Prima owns approximately 72,000 gross, 28,000 net, undeveloped acres on its Merna prospect located in Sublette County, Wyoming. The Company has entered into an agreement with a third party to support that party's effort to re-enter and complete one well and drill a second well on offsetting acreage. In exchange for information obtained from these operations, Prima has agreed to allow the third party to participate in the drilling of a test well on Prima's acreage within the next six months. Operations are currently being conducted on the initial well re-entry to test the over-pressured Lance interval.

The Board of Directors of Prima approved a $45 million capital expenditures budget for 2001. The Company expects that its operations, including drilling, completion and recompletion well costs, expansion of its service companies, undeveloped leasehold acquisitions and stock re-purchases will be financed by funds provided by operations, working capital, various cost-sharing arrangements, or from other financing alternatives. The Company also regularly reviews opportunities for acquisition of assets or companies related to the oil and gas industry which could expand or enhance its 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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Results of Operations

Quarters Ended June 30, 2001 and 2000

For the quarter ended June 30, 2001, the Company earned net income of $5,671,000, or $.43 per diluted share, on revenues of $14,188,000, compared to net income of $4,811,000, or $.36 per diluted share, on revenues of $12,081,000 for the comparable quarter of 2000. Expenses were $5,967,000 for the 2001 second quarter compared to $5,290,000 for the 2000 second quarter. Revenues increased $2,107,000, or 17%, expenses increased $677,000, or 13%, and net income increased $860,000, or 18%.

Oil and gas sales for the quarter ended June 30, 2001 were $11,909,000 compared to $10,235,000 for the same quarter of 2000, an increase of $1,674,000 or 16%. The increase is primarily attributable to higher natural gas prices. The average price received for natural gas production was $3.97 per Mcf for the 2001 quarter compared to $3.19 per Mcf for the 2000 quarter, an increase of $0.78 per Mcf or 24%. The average price received for oil in the second quarter of 2001 was $27.55 per barrel compared to $27.50 per barrel for the second quarter of 2000, an increase of $0.05 per barrel or less than 1%. On an Mcf equivalent basis, the average price received for the Company's production was $4.12 per Mcfe for the quarter ended June 30, 2001 compared to $3.51 per Mcfe for the quarter ended June 30, 2000. The Company's oil and gas revenues were 74% derived from the sales of natural gas during the 2001 quarter compared to 70% in the 2000 quarter. During the second quarter of 2001, the Company hedged approximately 27% of its natural gas production and 18% of its oil production. Hedging gains of $828,000 are included in oil and gas revenues for this period, which increased the average price received per Mcf of natural gas by $0.37 and per barrel of oil by $0.12. The Company did not hedge any of its production during the second quarter of 2000.

The Company's net natural gas production was 2,220,000 Mcf and 2,244,000 Mcf for the second quarters of 2001 and 2000, respectively, a decrease of 24,000 Mcf or 1%. Its net oil production was 112,000 barrels for both quarters. On an Mcf equivalent basis, the Company's second quarter production was 77% natural gas and 23% oil for both quarters. Production levels has decreased in the Powder River Basin conventional wells and the Wind River Basin wells due to natural declines and limited new activity. These declines were partially offset by slight production increases in the Denver Basin and by new production in the Powder River Basin Coalbed Methane play.

The Company's depletion expense for oil and gas properties was $1,852,000, or $0.64 per Mcfe, on 2,892,000 equivalent Mcf produced during the second quarter of 2001, compared to $1,492,000, or $0.51 per Mcfe, on 2,915,000 equivalent Mcf produced during the second quarter of 2000. The higher depletion rate reflects higher drilling and operating costs experienced during the fourth quarter of 2000. Depreciation of other fixed assets, which includes service equipment, furniture, office equipment and buildings, was $296,000 and $285,000 for the quarters ended June 30, 2001 and 2000, respectively.

Lease operating expenses ("LOE") were $651,000 for the quarter ended June 30, 2001 compared to $619,000 for the quarter ended June 30, 2000. Ad valorem and production taxes were $869,000 and $753,000 for the same periods. Production taxes increased with higher product prices. Total lifting costs (LOE plus ad valorem and production taxes) were 13% of oil and gas revenues and $0.53 per Mcfe for the 2001 quarter compared to 13% and $0.47 per Mcfe for the 2000 quarter.

Oilfield services represent the revenues earned by Action Oilfield Services, Inc. (Colorado) and Action Energy Services (Wyoming), wholly owned subsidiaries. These revenues include well servicing fees from completion and swab rigs, trucking, water hauling and rental equipment, and other related activities. Revenues were $2,006,000 for the quarter ended June 30, 2001 compared to $1,525,000 for the comparable quarter of 2000, an increase of $481,000, or 32%. Costs of oilfield services were $1,379,000 for the quarter ended June 30, 2001 compared to $1,338,000 for the same period of 2000, an increase of $41,000 or 3%. For the quarter ended June 30, 2001, 39% of the fees billed by the service companies were for Company owned wells compared to 34% for the quarter ended June 30, 2000. Intercompany billings are eliminated in consolidation.

General and administrative expenses ("G&A"), net of third party reimbursements and amounts capitalized, were $920,000 for the quarter ended June 30, 2001 compared to $803,000 for the quarter ended June 30, 2000, an increase of $117,000 or 15%. Third party reimbursement of management and operator fees were $98,000 and $102,000 during the quarter ended June 30, 2001 and 2000, respectively. The Company's G&A costs have otherwise increased due to expansion of the Company's activities and operations.

The provision for income taxes was $2,550,000 for the quarter ended June 30, 2001 compared to $1,980,000 for the quarter ended June 30, 2000, an increase of $570,000 or 29%. The Company's effective tax rate increased to 31.0% from 29.2%. The Company's effective tax rates are less than statutory rates due to permanent differences in financial and taxable income, consisting primarily of statutory depletion deductions and Section 29 tax credits. The Company's effective tax rate increased primarily because income before income taxes increased $1,430,000 or 21% for 2001, while the permanent differences did not increase proportionately.

Six Months Ended June 30, 2001 and 2000

For the six months ended June 30, 2001, the Company earned net income of $14,347,000, or $1.08 per diluted share, on revenues of $32,658,000, compared to net income of $8,995,000, or $.68 per diluted share, on revenues of $22,758,000 for the six months ended June 30, 2000. Expenses were $12,462,000 for the 2001 six month period compared to $10,193,000 for the 2000 six month period. Revenues increased $9,900,000, or 44%, expenses increased $2,269,000, or 22%, and net income increased $5,352,000, or 59%.

Oil and gas sales for the six months ended June 30, 2001 were $28,266,000 compared to $18,962,000 for the six months ended June 30, 2000, an increase of $9,304,000 or 49%. The average price received for natural gas production was $5.10 per Mcf for the six months ended June 30, 2001, compared to $2.91 per Mcf for the six months ended June 30, 2000, an increase of $2.19 per Mcf or 75%. The average price received for oil for the first six months of 2001 was $28.03 per barrel compared to $27.40 per barrel for the same period of 2000, an increase of $0.63 per barrel or 2%. On an Mcf equivalent basis, the average price received for the Company's production was $5.00 per Mcfe for the six months ended June 30, 2001 compared to $3.30 per Mcfe for the six months ended June 30, 2000. The Company's oil and gas revenues were 78% derived from the sales of natural gas during the first six months of 2001 compared to 68% during the first six months of 2000. During the six months ended June 30, 2001, the Company hedged approximately 32% of its natural gas production and 9% of its oil production. Net hedging gains of $1,250,000 increased the average price received per Mcf of natural gas by $0.29 and per barrel of oil by $0.06. The Company did not hedge any of its production during the six months ended June 30, 2000.

The Company's net natural gas production was 4,319,000 Mcf and 4,410,000 Mcf for the first six months of 2001 and 2000, respectively, a decrease of 91,000 Mcf or 2%. Its net oil production was 223,000 barrels compared to 224,000 barrels for the same six month periods, a decrease of 1,000 barrels or less than 1%. On an Mcf equivalent basis, the Company's production for the six months ended June 30, 2001 was 76% natural gas and 24% oil, compared to 77% natural gas and 23% oil for the same period of 2000.

The Company's depletion expense for oil and gas properties was $3,620,000, or $0.64 per Mcfe, on 5,657,000 equivalent Mcf produced during the first six months of 2001, compared to $2,943,000, or $0.51 per Mcfe, on 5,754,000 equivalent Mcf produced during the first six months of 2000. Depreciation of other fixed assets was $578,000 and $551,000 for the six months ended June 30, 2001 and 2000, respectively, an increase of $27,000, or 5%.

LOE was $1,450,000 for the six months ended June 30, 2001 compared to $1,255,000 for the six months ended June 30, 2000. Ad valorem and production taxes were $2,293,000 and $1,484,000 for the same periods. Total lifting costs were 13% of oil and gas revenues and $0.66 per Mcfe for the 2001 quarter compared to 14% and $0.48 per Mcfe for 2000.

Oilfield services revenues were $3,782,000 for the six months ended June 30, 2001 compared to $3,184,000 for the comparable six month period of 2000, an increase of $598,000 or 19%. Costs of oilfield services were $2,513,000 for the six months ended June 30, 2001 compared to $2,618,000 for the same period of 2000, a decrease of $105,000 or 4%. For the six months ended June 30, 2001, 39% of the fees billed by the service companies were for Company owned wells compared to 33% for the six months ended June 30, 2000.

G&A was $2,008,000 for the six months ended June 30, 2001 compared to $1,342,000 for the six months ended June 30, 2000, an increase of $666,000 or 50%. Third party reimbursements were $213,000 and $240,000 during the six months ended June 30, 2001 and 2000, respectively. Management fees received from third parties have decreased as the Company has acquired additional working interests in operated wells and sold interests in properties it previously operated.

The provision for income taxes, including the tax effect of a change in accounting principle, was $6,725,000 for the six months ended June 30, 2001 compared to $3,570,000 for the same six month period of 2000. Income before income taxes increased $7,631,000 for the 2001 six month period and the effective tax rate increased to 32.0% from 28.4%. The Company's provision for income taxes was 89% deferred in 2001 compared to 70% in 2000.

Historically, oil and natural gas prices have 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 the control of the Company. To the extent that oil and gas prices decline, the Company's revenues, cash flows, earnings and operations would be adversely impacted. The Company is unable to accurately predict future oil and natural gas prices.

The Company's primary source of revenues is the sale of oil and natural gas production. Levels of revenues and earnings are affected by volumes of oil and natural gas production and by the prices at which oil and natural gas are sold. As a result, the Company's operating results for any period are not necessarily indicative of future operating results because of fluctuations in oil and natural gas prices and production volumes.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company's primary market risks relate to changes in the prices received from sales of oil and natural gas. The Company periodically hedges a portion of the price risk associated with the sale of its oil and natural gas production through the use of derivative commodity instruments, which consist of commodity futures contracts, price swaps and basis swaps. These instruments reduce the Company's exposure to decreases in oil and natural gas prices and/or increases in basis differential between NYMEX and Rocky Mountain prices on the hedged portion of its production, by enabling it to effectively receive a fixed price for the hedged oil and gas production volumes. Such instruments also generally limit the benefits realized by the Company from increases in oil and natural gas prices on the hedged portion of its production. By hedging only a portion of its market risk exposures, the Company is able to participate in the increased earnings and cash flows associated with increases in oil and natural gas prices; however, it is exposed to risk on the unhedged portion of its oil and natural gas production.

The Company has derivative positions which are designed to hedge the Company's oil and natural gas prices from downward price movements and basis swaps to protect the Company from increases in the basis differential. The Company's derivatives either qualify as cash flow hedges or fair value hedges, and are accounted for accordingly.

Note 4 to the unaudited consolidated financial statements provides further disclosure with respect to derivatives and related accounting policies.

All derivative activity is carried out by personnel who have appropriate skills, experience and supervision. The personnel involved in derivative activity must follow prescribed trading limits and parameters that are regularly reviewed by the Company's Chief Executive Officer. All hedging transactions are approved by the Chief Executive Officer before they are entered into and significant transactions are reviewed by the Company's Board of Directors. The Company uses only conventional derivative instruments and attempts to manage its credit risk by entering into derivative contracts with reputable financial institutions.

Following are disclosures regarding the Company's market risk instruments. 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 will likely differ from the amounts disclosed below due to ongoing changes in risk exposure levels and concurrent adjustments to hedging positions. It is not possible to accurately predict future movements in oil and natural gas prices.

During the first six months of 2001, the Company sold 223,000 barrels of oil. A hypothetical decrease of $2.80 per barrel (10% of average prices for the period exclusive of hedging transactions) would have decreased the Company's production revenues by $624,000 for the period. The Company sold 4,319,000 Mcf of natural gas during the same period. A hypothetical decrease of $0.48 per Mcf (10% of average prices for the period exclusive of hedging transactions) would have decreased the Company's production revenues by $2,073,000 for the period.

The Company realized hedging and trading gains of $1,453,000 during July and August of 2001, which will be reflected in the Company's results for the third quarter of 2001. As of August 2, 2001, open hedging and trading positions for production through October 2002 showed net unrealized gains of $1,624,000, as follows:

Type of Derivative	Monthly Volume (MMBtu)	Term	Contract Price pe MMBtu
Natural gas basis swaps	240,000	Sept-November 2001	$0.4325
Natural gas basis swaps	(60,000)	September 2001	1.0775
Natural gas futures	600,000	Sept-November 2001	3.6383
Natural gas futures	400,000	Dec 2001-Feb 2002	3.8697
Natural gas futures	350,000	March 2002	3.7220
Natural gas futures	300,000	April-May 2002	3.5365
Natural gas futures	200,000	June-October 2002	3.7492

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" and 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," "believe," or "intend" and similar expressions identify forward-looking statements. Such statements are based on certain assumptions and analyses made by the Company in light of its experience and its perception of historical trends, current conditions, expected future developments and other factors it believes are 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 Company's 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 its oil and natural gas reserves; the substantial capital expenditures required to fund its 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 the Company's Annual Report on Form 10-K for the year ended December 31, 2000, beginning on page 19.

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PART II OTHER INFORMATION

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

On May 16, 2001, the Company held an annual meeting of stockholders. The following table sets forth certain information relating to each matter voted upon at the meeting.

Matters Voted Upon	For	Agains
Election of James R. Cummings as Class I Director.	10,771,404	
Election of George L. Seward as Class I Director.	10,810,754	
Approval of an amendment to the Certificate of Incorporation increasing the number of authorized shares of common stock to 35,000,000 shares.	10,888,871	244,07
Approval of the Prima Energy Corporation 2001 Stock Incentive Plan.	6,615,102	2,381,73
Ratification of the selection of Deloitte & Touche LLP as independent auditors for 2001.	11,122,860	4,75

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ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) Exhibits

The following exhibits are filed herewith pursuant to Rule 601 of Regulation S-K.

EXHIBIT NO.	DOCUMENT
3.1	Certificate of Amendment of the Certificate of Incorporation of Prima Energy Corporation
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 and filed June 6, 2001.)

(b) Reports on Form 8-K

The Company filed a Report on Form 8-K dated May 10, 2001, reporting its first quarter 2001 earnings and providing an operations update. The Company filed a Report on Form 8-K dated May 16, 2001, announcing the appointment of Neil L. Stenbuck to the Board of Directors to fill the vacancy created by the concurrent resignation of Mr. Robert E. Childress. Mr. Stenbuck was also appointed to the position of Chief Financial Officer of the Company. A Report on Form 8-K dated May 23, 2001 announced the approval of a Shareholder Rights Plan by Prima's Board of Directors.

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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 August 14, 2001 By /s/ Richard H. Lewis

Richard H. Lewis,
President

Date August 14, 2001 By /s/ Neil L. Stenbuck

Neil L. Stenbuck,
Executive Vice President - Finance

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INDEX TO EXHIBITS

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