PRIMA ENERGY CORP
Form 10-K
March 31, 2003

Table of Contents

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2002.

o Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

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, Colorado 80202
(Address of principal executive offices) (Zip Code)

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

Securities registered pursuant to Section 12(b) of the Act
None

Securities registered pursuant to Section 12(g) of the Act
Common Stock, $0.015 Par Value
(Title of Class)

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 o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of the Form 10-K or any amendment to this Form 10-K. o

Indicate by checkmark whether the Registrant is an accelerated filer (as defined in Rule 12b-2 of the Act).

Yes x No o

The aggregate market value of the 9,198,101 shares of voting stock held by non-affiliates of the Registrant, based upon the closing price of the common stock on June 28, 2002 of $22.79 per share as reported on the Nasdaq National Market, was $209,624,722. Shares of common stock held by each officer and director and by each person who owns 10% or more of the outstanding common stock have been excluded in that such persons may be deemed affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of March 11, 2003, Registrant had outstanding 12,829,310 shares of Common Stock, $0.015 Par Value, its only class of voting stock.

Document Incorporated by Reference

Parts of the following document are incorporated by reference to Items 10, 11, 12, and 13 of Part III of the Form 10-K Report: Definitive Proxy Statement for the Registrant s 2003 Annual Meeting of Stockholders.

TABLE OF CONTENTS

Table of Contents

TABLE OF CONTENTS

Table of Contents

PART I

ITEMS 1 and 2. BUSINESS and PROPERTIES

References in this report to Prima, the Company, we, us or our are intended to refer to Prima Energy Corporation and its consolidated subsidiaries. This report contains numerous forward-looking statements that 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 the drilling and completion of wells, well operations, utilization rates of oilfield service equipment, gathering and compression of wells, reserve estimates (including estimates for future net revenues associated with such reserves and the present value of such future net revenues), production, future prices, cash flow, investments, business strategies, and other plans and objectives of Prima management for future operations and activities and other such matters. The words, believes, plans, intends, estimates, projects, expects, anticipates, strategy, budgeted and similar expressions, identify statements.

Prima does not undertake to update, revise or correct any of the forward-looking information. Readers are cautioned that such forward-looking statements should be read in conjunction with Prima s disclosures under the heading: Cautionary Statement for the Purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995 beginning on page 23 of this report.

General The Company

Prima was incorporated in April 1980 for the purpose of engaging in the exploration for, and the acquisition, development and production of, crude oil and natural gas, and for other related business activities. In October 1980, Prima became publicly owned with a $3.6 million common stock offering. In subsequent years, our activities have been expanded to include oil and gas property operations, oilfield services, and, at times, natural gas gathering, marketing and trading. However, a substantial majority of Prima s consolidated assets and revenue continue to be related to its oil and gas production operations.

Our principal activities are organized into two operating segments. The larger of these consists of the acquisition, exploration, development and operation of oil and gas properties. The second segment is comprised of oilfield service operations conducted for unaffiliated third parties and for Prima. Although at times in the past, we have also been involved in oil and gas marketing and trading, and in gas gathering and compression operations, these activities were not significant during the three years ended December 31, 2002.

We have conducted our activities principally in the Rocky Mountain region of the United States. At the end of 2002, Prima controlled leasehold interests in, or owned, over 575,000 gross, 404,000 net, acres, predominately in the Denver Basin of Colorado, the Powder River, Wind River, Big Horn and Green River Basins of Wyoming and within the Wasatch Plateau and Overthrust Belt of Utah. For additional information about these areas and Prima s oil and gas properties, see Oil And Gas Production Operations below.

We have identified more than 1,400 potential exploitation and development opportunities on our acreage as of the end of 2002, including drilling, recompletion and refracturing projects. Of these, 344 were assigned proved oil and gas reserves at year-end 2002. Most of the identified non-proved opportunities represent potential drilling locations on our acreage in the Powder River Basin coalbed methane (CBM) play. This set of identified opportunities includes only those projects that we believe have the potential to be economically viable using unescalated year-end 2002 oil and gas prices.

Our oil and gas exploration, development and production operations are conducted predominantly within Prima Oil & Gas Company, a wholly owned subsidiary. We conduct most other activities within wholly owned subsidiaries of Prima Oil & Gas Company, including: Action Oil Field Services, Inc. and Action Energy Services for oilfield services; Arete Gathering Company, LLC for natural gas gathering and compression; and Prima Natural Gas Marketing, Inc. for natural gas marketing and trading. For additional information related to our business segments, including revenues, operating earnings, and total assets, see Segment Information in Note 6 within Notes to Consolidated Financial Statements.

Table of Contents

At December 31, 2002, we reported the following:

$141,927,000 of assets.

$35,954,000 of net working capital.

Estimated net proved reserves of 111,104,000 Mcfe, with a pre-tax present value using a 10% discount factor (PV10) of $128,843,000, based on constant year-end average price realizations of $2.64 per Mcf of natural gas and $31.30 per barrel of oil.

Approximately 543,000 gross, 378,000 net, undeveloped acres and 32,000 gross, 26,000 net, developed acres.

Operations of 616 productive wells, representing approximately 91% of the productive wells in which Prima owns a working interest.

For the year ended December 31, 2002, we reported the following:

Net income of $5,230,000.

Net cash provided by operating activities of $21,524,000.

Average daily net production of 22,858 Mcf of natural gas and 1,022 barrels of crude oil (28,989 Mcfe).

Average price realizations of $1.97 per Mcf of natural gas and $25.14 per barrel of crude oil.

Strategy

***Objectives*.** We seek to create shareholder value by identifying, evaluating and capturing opportunities related to the oil and gas industry. Most of our investment activities have been, and are projected to be, associated with our exploration and production operations, including the acquisition, exploration, development, and exploitation of properties, and production of oil and gas. We have also invested and conducted operations in oilfield services, gas gathering and processing, and in oil and gas marketing and trading, and we intend to continue seeking such opportunities in the future. One of Prima s goals is to be among the lowest-cost producers of oil and gas, and to realize among the highest cash flow margins for reinvestment, in the industry. Through our related activities in oilfield services, gas gathering and processing, and oil and gas marketing and trading, we seek to complement and reinforce the achievement of goals in our exploration and production operations, and to enhance overall total returns to shareholders.

***Acreage*.** We seek to acquire oil and gas mineral rights under leasehold acreage in prospective areas, at reasonable costs and with attractive terms. We can potentially benefit from the activities of other operators in these areas as well as from our own activities.

Operations. We generally prefer to operate oil and gas properties in which we own significant economic interests. As operator, we are in a better position to control costs, the timing and quality of work performed, safety and other factors that can affect the profitability of a property.

Exploitation. We intend to continue property exploitation activities in our principal operating areas. In the Denver Basin, we plan to continue well refracturing, recompletions and development drilling, to the extent warranted by ongoing results and market conditions. We also plan to continue exploitation activities in the Powder River Basin, for both coal seam and conventional reservoirs, and in the Wind River Basin, depending upon the merit of each activity and subject to regulatory considerations. We generally assess these activities as low-to-moderate risk endeavors that would be undertaken when projected to meet our economic criteria, and as permitted by regulatory authorities.

Exploration. We generally seek to allocate 5% to 20% of our capital expenditures budget toward higher-risk exploration activities. These activities may include leasehold acquisitions, geologic and geophysical evaluation, and drilling test wells on prospects. Our exploratory prospects can be either internally generated or result from acquiring interests in other operators prospects. The objective of our exploration activities is to expose a portion of our capital to higher-risk projects that we believe have the potential to deliver high rates of return if successful. As compared to individual exploitation opportunities, a successful exploration project could have a more significant impact on Prima s value but the likelihood of success is considerably lower.

Gathering, Marketing and Trading. We elect to market our own natural gas and crude oil production whenever we believe that we can enhance our net price realizations by doing so. At times, Prima may also own assets downstream of the wellhead, including, but not limited to, gathering and compression facilities. We invest in such downstream assets where we believe opportunities exist to enhance Prima s overall project economics by capturing an additional portion of the value chain from the wellhead to the burner tip. We may also gather, compress and market third-party gas, if we expect that project rates of return will be attractive.

Oilfield Services. We believe that we can, at times, achieve better control of the timing, quality and cost of work performed on our wells by owning and operating well servicing equipment. We also intend for these activities to constitute a separate business segment and profit center through providing such services to other operators.

Mergers, Acquisitions and Divestitures. We regularly review merger, acquisition and divestiture opportunities related to the oil and gas industry that could complement or enhance Prima s existing businesses. Such transactions are pursued and consummated, where possible, when we believe that they would improve the risk-adjusted returns realized by Prima s shareholders over the long term.

Derivatives. We periodically use commodity futures contracts to mitigate the impact of the volatility of oil and natural gas prices on a portion of our production and gas marketing activities. Our use of such derivatives is also intended to improve our average oil and gas price realizations over time, to enhance profitability, though such outcome cannot be assured. We may also elect at times to enter into derivatives contracts for volumes that exceed our projected total production, or which increase, rather than decrease, our exposure to a decline in oil and gas prices or expansion of basis differentials. We would consider establishing such positions if our analyses lead us to believe that prices are likely to move in a manner that would generate gains from the positions. Derivative positions for volumes greater than our expected production, or which would increase our exposure to a decline in oil and gas prices or expansion of basis differentials, would be speculative and would be limited in size to an amount that, in management s judgment would not be material to our balance sheet taken as a whole, but they might have a significant positive or negative impact on reported net earnings.

Oil and Gas Production Operations

Denver Basin

Location, Operations and Acreage. Our activities in the Denver Basin are conducted primarily in the Wattenberg Area, which encompasses more than 1,000 square miles, between 20 and 55 miles northeast of Denver, Colorado. We also own leasehold interests and conduct operations on 4,480 acres near Denver International Airport (DIA), where we have drilled and completed ten wells. We have conducted operations in the Denver Basin for more than 20 years, and at the end of 2002, operated 411 wells in the area, including those near DIA. Our leasehold position in the Denver Basin at that date included 18,100 gross (15,500 net) developed acres, and an additional 13,000 gross (12,000 net) undeveloped acres.

Formations and Production. Our drilling and production activities to date in the Denver Basin have been centered in a portion of the Wattenberg Field where the primary productive reservoirs are found in the Codell and Niobrara formations. The Codell and Niobrara formations blanket large areas of the field at depths of approximately 7,000 to 7,300 feet and have moderate porosity and low permeability. These formations require fracture stimulation to establish economic production. Recoverable reserves from any individual wellbore are largely dependent on reservoir quality, sand thickness, and fracture stimulation techniques.

Our Denver Basin wells produce both natural gas and crude oil. Prima s natural gas production in this area averages approximately 1,240 Btu per Mcf at the wellhead. Natural gas liquids (propane, butane, ethane, isobutane, pentane) are processed out of the well stream and sold separately by third-party gatherer/purchasers but their value is reflected in our wellhead price for natural gas. Generally, our average gas price realizations per Mcf in this area have slightly exceeded

Table of Contents

Rocky Mountain spot prices due to the high Btu content of the gas, but this relationship varies with market conditions and is dependent, in part, on the price levels of natural gas liquids. Our crude oil in this area is sweet and generally commands a premium to Northeast Colorado and West Texas Intermediate postings. During 2002, Denver Basin properties accounted for approximately 73% of our total Mcfe produced and 82% of our total oil and gas revenues excluding hedging effects, with natural gas averaging 15,288 Mcf per day and crude oil averaging 987 barrels per day net to our interests.

Reserves and Development Costs. The Denver Basin represented 66% of our proved oil and gas reserves on an Mcfe basis at the end of 2002. Codell/Niobrara wells that we recently drilled and completed in this area generally cost approximately $285,000 and target approximately 200,000 to 250,000 Mcfe of gross recoverable reserves per well. At year-end 2002, we controlled approximately 230 potential drill sites in the Denver Basin, with 60 of these attributed proved undeveloped reserves. Our strategy has been to selectively drill wells utilizing advanced drilling and completion techniques, focusing on cost controls, and varying activity levels based upon regional oil and gas prices, to enhance economic returns. There is no assurance that the potential locations that have been identified will be drilled or that such wells, if drilled, will result in commercial production.

Codell/Niobrara Refracturing. Advancements in refracturing (refrac) stimulation technology have enabled us to add deliverability and reserves from the Codell and Niobrara formations. A refrac is a procedure in which a formation in an older well, which has been previously fractured at least once, is stimulated by another fracture treatment. We generally target older wells with declining deliverability for restimulation. Refracs completed by Prima in 2002 resulted in initial incremental production rates averaging 150 Mcfe of oil and natural gas per day. The refracs cost an average of approximately $120,000 and targeted approximately 125,000 Mcfe of gross incremental recoverable reserves.

2002 Activity. During 2002, we participated in the drilling of 14 gross (13.2 net) wells and the refracturing of 34 gross (30.5 net) wells in the Denver Basin. All of these operations were successfully completed and all of the wells have been placed on or returned to production. New wells, refracs and recompletion operations in the Denver Basin are characterized by flush production at relatively high rates for a few months, after which lower production levels are established at relatively shallow decline rates. We generally accelerate these operations when oil and gas prices are high and defer them when prices are low, to enhance the impact on investment returns from the flush production. In early 2002, we elected to maintain a comparatively low level of drilling and refrac operations because of relatively low oil and gas prices, and high line-pressure attributable to limited processing capacity in the area. In response to subsequent improvements in oil and gas prices, and the completion of an expansion of a third-party owned gas-processing plant, we accelerated such operations in the fourth quarter of 2002.

Future Activity. We plan to continue our development and exploitation activities in the Denver Basin. We are currently budgeting for capital investments in the Denver Basin aggregating between $6 million and $8 million in 2003. Planned activities include approximately 15 to 25 new Codell/Niobrara wells (including two wells in progress at year end 2002) and 30 Codell/Niobrara refracs. However, our plans are subject to revision based on economic conditions, performance results, activities conducted in other areas, and other factors.

Powder River Basin Coalbed Methane

Location, Operations, Acreage. The coalbed methane play in the Powder River Basin is prospective over a vast geographic area encompassing approximately three million acres in northeastern Wyoming. According to the Wyoming Oil & Gas Commission, over 15,000 CBM wells have been drilled to date, and approximately 10,700 wells were producing approximately 957 MMcf of natural gas per day during December 2002. At times during the past four years, this has been the most active drilling play in the United States. Although activity levels moderated in 2002, in response to pending resolution of federal land use issues (discussed below), depressed regional gas prices, and other factors, significant estimated potential gas reserves remain unexploited in the area.

We began our Powder River Basin CBM activities in 1999, and our operations have included leasehold acquisition, drilling and completion of 342 wells, infrastructure development, production, oilfield services, and gas gathering and compression. We assembled a significant leasehold position within the play, much of which lies close to gathering and transportation infrastructure. Our acreage in the area has included parcels in various portions of the play, from the southernmost part of the prospective area to its known limits on the northern end. In March 2002, we sold much of the CBM acreage that we had assembled in the northernmost portion of the play, including our partially-developed Stones Throw project with 153 wells, for approximately $13,514,000. This project area had been an early area of focus for Prima in the CBM play because it was located near properties being developed by other operators, close to existing gas transportation infrastructure, and because the combination of fee leaseholds and the availability of special drainage permits to drill on federal lands facilitated activities. However, the coals at Stones Throw were relatively shallow and thin, and we did not obtain the economic results that we had anticipated.

As a consequence of information and experience gained at Stones Throw and from other activities that we have conducted, as well as through monitoring the experience of other operators, we have concluded that the best remaining opportunities in the Powder River Basin CBM play lie in development of deeper, thicker coals (below 800 depth and greater than 35 thick). Although much of our early drilling operations were targeted toward shallower coals that had been more extensively developed by other operators on surrounding acreage, we began focusing in 2002 on CBM projects with larger-reserve potential in coals generally found at greater depths, but which are not yet established as proved. Establishing proved CBM reserves and production from such coals will take time, as they are untested in most of the basin and extensive de-watering will need to occur before significant quantities of gas production are realized.

The pace of development of these coals by us and other operators will also be influenced by water management requirements that will be more complex than for earlier CBM development, and extensive state and federal regulatory conditions. However, we believe that these unproved deeper, thicker coals, such as the Big George and Wall coals, hold the potential for significant future growth in Prima s proved reserves and production, and initial results from several early-stage pilot projects being conducted by other operators in the area are encouraging. In addition, some attractive projects to develop relatively thick, high-permeability coals at shallower depths are still available in this play, as exemplified by our project in the Porcupine-Tuit area, which is discussed below.

At December 31, 2002, we held 111,300 gross (99,800 net) acres in the Powder River Basin CBM play, of which 9,900 gross (8,900 net) were developed and 101,400 gross (90,900 net) were undeveloped. This acreage is comprised of approximately 83% federal, 7% state, and 10% fee (private) leases. Generally, the federal leases have an initial ten-year term, state leases have a five-year term, and the terms of fee leases vary from a few months to several years. The primary lease terms of federal acreage have generally been extended for the period that access to the lands has been restricted while an environmental impact statement has been under preparation. For convenience of managing operations, we have organized our current Powder River Basin CBM acreage holdings into 22 defined project areas.

Formation and Production. The primary target coals are located in the Fort Union formation at depths ranging from 600 feet to 2,000 feet. It is common to encounter multiple coal zones varying in thickness from a few feet to over 150 feet between these depths. The methane in coal beds is adsorbed, or attached, within the coal layers and is held in place by water within the coals. When water is produced from the coal seam, the pressure is reduced, allowing the gas to desorb from the coal. Operators in the area have experienced de-watering times ranging from a few days to over one year, with the de-watering time influenced by well density, coal depth, permeability, well location and other factors.

Gas production rates from individual wells in the play have ranged from a few Mcf per day to over 1,000 Mcf per day after sufficient de-watering, and have averaged approximately 100 Mcf per day to date. Most of the gas production to date has been obtained from relatively shallow Wyodak coals where development was initially focused. Future development activities in the play are expected to focus largely on deeper coals with higher estimated potential reserves and production rates.

To produce gas in this CBM play, wells must generally be hooked-up to a low-pressure gathering system and compression, commonly referred to as screw compression, which holds wellhead pressures to approximately five pounds per square inch gauged (psig). The gas must then move through a gathering system where, at its terminus, gas needs to be boosted to about 1,400 psig to enter a high-pressure header-system line. This high-pressure boost is commonly referred to as reciprocating (or recip) compression. CBM gas from this area is generally somewhat less than 1,000 Btu per Mcf and may require carbon dioxide extraction to meet interstate pipeline gas quality specifications. Due

Table of Contents

to relatively high compression and transportation costs, net price realizations for this gas are below Rocky Mountain indices. The amount of this discount varies with the nominal level of the indices, Btu content of the gas, location of the property, and other factors, but averaged approximately $0.87 per Mcf in 2002.

We established our first significant Powder River Basin CBM production in 2001 from the Stones Throw property, where production rates increased over several months to a level in excess of 8,000 Mcf per day gross at the time the property was sold in March 2002. In late July 2002, we initiated production at our Porcupine-Tuit CBM property, from 27 wells. Production from this property increased over the balance of the year, as wells de-watered, more wells were hooked up, and additional third-party-owned compression capacity was installed. During December 2002, the Porcupine-Tuit property produced an average 13,500 Mcf per day gross (approximately 10,400 Mcf per day net) from 48 wells. Overall in 2002, Powder River Basin CBM properties accounted for approximately 15% of our total Mcfe produced and 7% of our total oil and gas revenues excluding hedging effects, with net gas production averaging 4,318 Mcf per day for the full year and 8,582 Mcf per day in the final quarter of the year.

Reserves and Development Costs. Powder River Basin CBM properties accounted for 28% of our year-end proved oil and gas reserves on an Mcfe basis at the end of 2002. CBM wells generally cost from $50,000 to $100,000 to drill, equip and complete, depending on location and depth, and a similar amount for supporting infrastructure, including surface equipment, water management facilities, and connections to sales meters. A typical well is expected to establish gross recoverable reserves of 250,000 to 500,000 Mcf. At year-end 2002, Prima s reserve report for the CBM area included 91 proved developed producing wells, 23 wells classified as proved developed non-producing and 115 locations assigned proved undeveloped reserves. Based on engineering estimates prepared as of December 31, 2002, we estimate that we have a potential inventory of over 950 additional non-proved drill sites in this play, subject to economic viability that will be dependent upon projected regional gas prices, estimated development and operating costs, drilling results from activities by Prima and other operators and other factors. We caution, however, that the play is not uniform, and estimated potential reserves and production capabilities vary considerably depending on location, thickness and depths of coals, number of coals present, permeability, gas content, and a number of other factors. There is no assurance that these potential wells will be drilled or that any that are drilled will ultimately establish economic reserves.

Permits Drilling, Water Discharge and Air Quality. Operations in this area, which includes significant amounts of land controlled by federal or state governments, are extensively regulated. Drilling permits are issued by the Wyoming Oil & Gas Commission. In order to conduct operations on federal leaseholds, drilling permits must also be approved by the Bureau of Land Management (BLM), subject to environmental regulations. The Wyodak environmental impact statement (EIS) was completed in 1999 to facilitate early development in the Powder River Basin CBM play, and provided for the drilling of approximately 5,900 wells. These permits have all been issued, and there has essentially been a moratorium on issuing drilling permits for federal leaseholds pending issuance of another EIS, unless the location qualified under an environmental assessment that provided for issuance of approximately 2,500 special drainage permits.

The pending EIS, which is expected to consider the environmental impact of drilling approximately 50,000 CBM wells in the area, inclusive of wells drilled to date, is currently in process and a record of decision is expected in the second quarter of 2003. We anticipate much greater accessibility to our federal acreage after this EIS is issued. However, if a final record of decision for the EIS is delayed or we encounter significant delays in the issuance of additional drilling permits on our federal acreage for any other reason, our development plans for the area would be significantly impacted.

Water produced from CBM wells is generally potable (drinking water quality) and can be discharged on the surface. The Wyoming Department of Environmental Quality (DEQ) is responsible for considering applications for water discharge permits. During the past year, issuance of water discharge permits was slowed in order to address the sodium absorption ratio and mineral content of water discharged in the basin and its potential impact on agriculture. This issue is most acute for producers in the northwestern portion of the play and Prima s operations are focused primarily on the eastern side of the basin. A principal alternative to surface drainage discharge for water management is containment, or impoundment, which increases development and operating costs. Air discharge permits, which are required to operate natural gas fired compressors, are also issued by the DEQ, and take approximately six months to be issued. We have not encountered significant difficulties to date in acquiring air permits for our CBM operations.

Natural Gas Transportation Infrastructure. The transportation infrastructure in this basin is currently capable of moving approximately 1.4 Bcf per day of natural gas. High-pressure header systems, including Bighorn Gas Gathering LLC, Fort Union Gas Gathering LLC, and Thunder Creek Gas Services LLC, feed downstream into interstate pipeline capacity provided by Colorado Interstate Gas Company, Wyoming Interstate Pipeline, KM Interstate, Williston Basin Interstate Pipeline, and MIGC Inc. Downstream of these interstate pipelines, the pipeline grid is being enhanced by three projects. Kern River Pipeline is expected to be on line in May 2003 with an additional 900,000 Mcf per day of capacity that will move gas from southwest Wyoming to Nevada and California markets. Williston Basin Interstate Pipeline s Grasslands project is scheduled to move an additional 80,000 Mcf per day north out of the basin to mid-continent markets beginning in November of 2003. In the summer of 2005, El Paso Corporation s Cheyenne Plains project is anticipated to establish new capacity to move 540,000 Mcf per day from Cheyenne, Wyoming to mid-continent markets. Northern Border Partners L.P. and Kinder Morgan pipelines have also announced potential projects to move gas from the basin, but firm commitments and dates are pending. We estimate that at year-end 2002, about 950,000 Mcf per day of CBM gas was flowing. We caution that Prima does not own firm transportation for its own account, and could have difficulty moving gas from the basin if pipelines fill to capacity. Under the terms of an agreement with a third party that controls firm header and pipeline capacity from the basin, Prima does retain the right, at certain junctures, to enter into a firm gathering arrangement for up to 5,000 Mcf per day of its Powder River Basin CBM gas production.

2002 Activity. During 2002, we drilled 56 gross (47.8 net) CBM wells in this play. From 1999, when we commenced our CBM operations, through the end of 2002, we drilled a total of 342 gross (331.6 net) wells and acquired an interest in five additional wells in the play. All but a few of these wells are located within five of the 22 project areas that we have identified on our current acreage holdings, or in the Stones Throw project area, which was sold in March 2002. The concentration of Prima s development activities to-date within these project areas, and on the specific coals targeted so far, reflects a number of considerations other than estimated recoverable reserves and projected production rates. Our CBM activities have been limited to fee lands, state lands, and certain coals underlying federal lands for which drilling permits have been obtainable. These activities have largely been focused on relatively shallow coals, near development activities of other operators. The higher-potential coals identified on Prima s lands have not yet been extensively developed, and have not been attributed any proved reserves as of December 31, 2002. Other operators in the area are also in the early stages of developing these deeper, thicker coal sequences, which are expected to initially take longer to de-water than coals that have been under development and production in the region for a period of time. The following is a brief description of activities in the six project areas where most of Prima s CBM operations have been conducted to-date (including the Stones Throw property that was sold), and our Wild Turkey project area, where we expect to commence drilling operations later this year.

<u>Porcupine-Tuit.</u> The 11,000-acre Porcupine-Tuit project area is located approximately 50 miles south of Gillette, Wyoming. We have drilled 62 Wyodak-coal wells, including 39 in 2002, in this project area, which exhibits favorable coal quality and thickness at relatively shallow depths. During 2002, we commenced production from 58 of these wells, including 27 wells in the third quarter and 31 wells in the fourth quarter of the year. Well production rates have generally met or exceeded our expectations to date. At the end of the year these wells were averaging a combined 14,000 Mcf per day, gross (approximately 10,800 Mcf net), with several wells still de-watering. By late-February 2003, gross production had ramped up further, to a level of approximately 18,000 Mcf per day. We expect gross production to increase to approximately 21,000 Mcf per day in the second quarter, when the third-party contracted to gather this gas is planning to install additional compression.

We intend to hook-up the four shut-in wells during the second half of 2003, along with wells drilled during the next phase of development, which will commence as soon as practicable after approvals are received for 26 drilling permits for which applications have been submitted. We have been delayed in obtaining permits to drill these wells due to regulatory review and an appeal of the Forest Service s decision to approve our requested permits. We anticipate a favorable resolution of this appeal and are currently planning to drill these wells beginning in the third quarter of 2003. However, this scheduled drilling is dependent upon receiving permit approvals from both the Forest Service and the Bureau of Land Management, and further delays could be encountered. Prima s net working and revenue interests in the 88 Porcupine-Tuit wells that have either been drilled or are expected to be drilled in 2003 average approximately 93% and 78%, respectively.

Table of Contents

Kingsbury. Our Kingsbury project area is located approximately 15 miles west of Gillette, Wyoming. In November 2002, we contributed approximately 5,900 of the 10,300 acres that we controlled in the Kingsbury area to a new joint venture formed with a private company to develop coal bed methane resources within an area comprising an aggregate 11,600 gross acres (9,800 net acres, to the joint-venture interests). The joint-venture area encompasses our Kingsbury deep-coal pilot project, which we designed to begin testing two coals found at depths between 1,500 feet and 2,000 feet that have not yet been extensively developed in the area. Our acreage contribution to, and ownership stake in, the joint venture are approximately 60%, and Prima is the operator of the project. Late in 2002, we completed and placed on pump the 16 wells that comprise the initial-stage pilot in this area. These wells are not expected to produce gas for several months, as the initial de-watering process occurs, and they have not yet been tied into a gas gathering system. In addition to these 16 wells, the JV holds interests in 22 wells, most of which were drilled to shallower coals, which have either not yet been hooked up or are producing at marginal rates. Through formation of this joint venture, Prima maintained its overall exposure to deep-coal potential in this area, which is projected to be significant, while reducing its net risk capital to evaluate these probable reserves. We also expect to realize improved cost efficiencies in developing and operating the property. We anticipate arranging for a third party to install or expand a gathering system and compression facilities at Kingsbury by late 2003. Within the Kingsbury area, but outside of the JV, we closed 2002 with 17 shallow-coal wells that were drilled in prior years, on 4,400 gross and net acres. In January 2003, we sold 1,120 of these acres, with 8 wells that were producing an aggregate of approximately 150 Mcf per day net, for $1,200,000.

Cedar Draw and North Shell Draw. We have drilled 53 wells within these two adjacent project areas, in which we control an aggregate 15,300 gross acres, approximately 20 to 25 miles northwest of Gillette, Wyoming. Seventeen of the wells have been drilled within the 3,800-acre Echeta federal unit, which comprises a portion of the Cedar Draw and North Shell Draw project areas. Of the total wells drilled within these projects, 42 targeted the Lower Anderson coal at a depth of approximately 500 feet, seven were drilled for the Upper Canyon coal at a depth of approximately 800 feet, and four were drilled to the Wall coal at approximately a 1,200-foot depth. The Cedar Draw and North Shell Draw project areas are located in reasonably close proximity to the Kingsbury project, and we expect to coordinate development of these areas, including installation of gas gathering and compression facilities. We also anticipate that our near-term drilling activities in the Cedar Draw and North Shell Draw area will focus primarily on the Wall coal.

Hensley. The 4,800-acre Hensley project area is located approximately 20 miles northwest of Gillette, Wyoming. Prima has drilled and completed 18 wells in the project area. These wells, which were drilled prior to 2002, targeted three separate coals between 600 feet and 1,200 feet deep. We have deferred further development in this area, including installation of surface facilities, and arranging for gas gathering, in order to focus our resources on project areas that are believed to have higher potential. We do not plan additional near-term activities at Hensley, but will likely pool our acreage with another operator, sell the property, or resume activities at a later date.

Stones Throw (sold March 2002). The 9,900-acre Stones Throw project area, located approximately 30 miles north of Gillette, Wyoming, was the first chosen by Prima for extensive CBM development. Its selection was due to our control of a significant portion of fee acreage within the project area and its proximity to both an existing CBM field and related infrastructure. We drilled a total of 153 wells at Stones Throw to develop three coals at depths between 500 feet and 850 feet, and we also installed a gas gathering system with leased compression facilities. Gross production from the field reached approximately 8 MMcf of gas per day and averaged 5.4 MMcf per day net to Prima during the first two months of 2002, from 106 wells that were hooked up and producing during the period. This field, the associated gathering system, and certain surrounding acreage with three shut-in wells were sold in March 2002 for $13,514,000, following our decision to focus future CBM exploitation and development activities on other lease holdings in the play where we believe the presence of thicker, and generally deeper, coals will enable us to realize superior investment returns.

Table of Contents

Wild Turkey. The 6,300-acre Wild Turkey project area is located approximately 25 miles southwest of Gillette, Wyoming. This project will target the development of the Big George coal, which is found at a depth from 1,200 feet to 1,400 feet, and which we anticipate will vary in thickness from 100 feet to potentially over 160 feet based upon nearby subsurface well control. The closest established production from the Big George coal is coming from another operator s project located six miles to the southwest of Wild Turkey. That property was currently producing approximately 20,000 Mcf of gas per day from 70 wells as of December 2002. The Big George coal in our Wild Turkey project is expected to have similar thickness at a comparable depth, as this property six miles to the southwest. Prima has not yet drilled any wells on the Wild Turkey acreage block. Our current plans call for the drilling of 26 wells in 2003 to initiate evaluation and development. Further drilling is planned for 2004 and 2005, subject to governmental and regulatory approvals.

Future Activity. We plan to actively develop our CBM acreage over a multi-year period, focusing primarily on the Porcupine-Tuit area and areas, such as Kingsbury and Wild Turkey, where we have identified deeper, thicker coal seams that we believe hold potential for significant reserve additions. The pace of our activities will reflect a number of considerations, including the levels of gas prices and oilfield service costs, regulatory actions, infrastructure development, activities by other operators, and performance results. Currently, we anticipate drilling between 75 and 90 CBM wells in 2003, the majority of which are scheduled for the second half of the year due, in part, to expected time required to secure drilling permits. Among the project areas with planned drilling activities in 2003 are Porcupine-Tuit, Kingsbury, Cedar Draw, and Wild Turkey. Our capital investments in this CBM play during 2003 are currently expected to total between $12 million and $15 million, but these plans could change based on availability of required permits and other factors.

Powder River Basin Conventional

Location, Operations, Acreage. We have conducted operations related to conventional reservoirs in the Powder River Basin since 1994. At the end of 2002, we controlled deep rights (below the coals) under approximately 162,000 gross (149,000 net) acres in the basin, and we operated 13 of the 17 conventional-reservoir Powder River Basin wells in which we owned an interest. We have conducted a modest amount of exploration in the area, in addition to acquiring proved properties, and discovered the Cedar Draw Field approximately 21 miles northwest of Gillette, Wyoming in 1997 as an extension to the Amos Draw Field. At the end of 2002, Prima operated six wells and had a non-operated working interest in two other wells in the Cedar Draw Field.

Formations and Production. Our production from conventional reservoirs in the Powder River Basin has been derived primarily from the Muddy and Turner formations, found at depths between approximately 9,500 feet and 10,000 feet. Both of these formations are localized in nature, have moderate porosity and permeability, and typically require fracture stimulation to establish economic production. The production stream from these two formations includes natural gas, extracted natural gas liquids, and sweet crude oil. Natural gas averages approximately 1,280 Btu per Mcf and is sold at a slight premium to Rocky Mountain indices, or spot prices per Mcf. The crude oil sells for a premium to postings for Wyoming crude oil in this area. During 2002, production from conventional Powder River Basin properties accounted for approximately 6% of our Mcfe produced and 6% of our total oil and gas revenues excluding hedging effects, with natural gas averaging 1,621 Mcf per day and crude oil averaging 31 barrels per day net to our interests.

Reserves and Development Costs. Powder River Basin conventional properties accounted for approximately 3% of Prima s proved oil and gas reserves at the end of 2002, on an Mcfe basis. At the end of 2002, we carried only proved developed reserves in our reserve report for conventional reservoirs in this area, but additional drilling locations may be viable at higher gas prices. We have also identified several conventional exploratory prospects on our Powder River Basin acreage. The identified exploratory and exploitation locations are primarily prospective in the Muddy formation, for which estimated costs to drill and complete a well are approximately $800,000, with average gross reserve targets of 1.2 Bcfe to 1.5 Bcfe per well.

2002 and Future Activity. We did not drill any conventional wells in the Powder River Basin in 2002. We also do not have any specific plans to drill wells targeting conventional reservoirs in the Powder River Basin in 2003, but we do

Table of Contents

intend to continue our evaluations of prospects and leads in the conventional play, and these plans may change as a result.

Cave Gulch (Wind River Basin)

Location, Operations and Acreage. Prima has been active in the Wind River Basin, located in central Wyoming, since 1987. Our Wind River Basin acreage position is comprised of 1,200 gross (150 net) developed acres and 41,000 gross (25,000 net) undeveloped acres. Our oil and gas production in the basin is primarily attributable to ownership of non-operated working interests in the Cave Gulch Field, but we also operate one well and own small overriding royalty interests in a number of wells. At the end of 2002, we owned working interests averaging approximately 7%, in 34 producing wells at Cave Gulch Field.

Formations and Production. Several formations produce in the Cave Gulch Field, including the Fort Union at approximately 4,500 feet, the Lance between 4,900 and 9,200 feet, and the Frontier and Muddy formations between 17,000 and 18,200 feet. The Fort Union and Lance formations are both thick fluvial deposits with multiple, stacked lenticular sandstones that are laterally discontinuous. The Frontier and Muddy formations are a series of shallow marine channel, delta and offshore bars with locally enhanced porosity and permeability. Production from Cave Gulch Field includes natural gas, natural gas liquids and sweet crude oil. The natural gas averages 1,150 Btu per Mcf and is sold at a slight premium per Mcf to Rocky Mountain indices, or spot prices. The crude oil sells for a premium to postings for Wyoming crude oil in this area. During 2002, net production from Prima s Wind River properties accounted for approximately 6% of our total Mcfe produced and 5% of our total oil and gas revenues excluding hedging effects, with natural gas averaging 1,631 Mcf per day and crude oil averaging 4 barrels per day net to our interests.

Reserves and Development Costs. The Wind River Basin represented approximately 3% of Prima s proved oil and gas reserves at the end of 2002, on an Mcfe basis. The year-end 2002 reserve report for this area includes six proved developed non-producing re-completion opportunities, but no proved undeveloped locations. There are, however, identified opportunities to drill for unproved reserves within or near the Cave Gulch Field. Generally, these opportunities target the Lance formation. Lance formation wells typically cost approximately $1.3 million to drill and complete, and target gross reserves of approximately 2 Bcfe.

2002 And Future Activity. Prima participated in the drilling of five gross (0.5 net) wells at Cave Gulch Field during 2002, including two wells in progress at year-end. All five wells were drilled to develop reserves in the Lance formation. Four were apparent successes, and the other well may be abandoned due to mechanical problems. Our activities at Cave Gulch Field are determined to a large extent by the operator of the property, who proposes drilling or re-completion operations pursuant to standard industry operating agreements. We review each proposed operation and elect whether or not to participate based on our assessment of the economic and geologic merit. We anticipate additional activity in the field during 2003. Although the level of such activity has not been established yet, we anticipate receiving proposals to drill as many as 10 wells and to recomplete up to another 10 wells, with Prima working interests in such operations ranging up to 18% and averaging approximately 7%. We anticipate net investments in this area aggregating between $1 million and $2 million in 2003.

Other Exploratory Prospects and Acreage

Prima holds the following undeveloped acreage positions where recent activities have occurred, or where we anticipate that near-term activities conducted by Prima or third parties may benefit us. There is no assurance that any of the anticipated activities will occur or, if undertaken, that they will result in favorable outcomes.

Utah. Prima s assets in Utah primarily consist of exploratory acreage holdings and a related well in progress. At the end of 2002, we held approximately 105,000 gross (102,000 net) undeveloped acres in Utah, on which we had identified four prospects that have conventional oil and gas potential, as well as coal bed methane potential.

Coyote Flats Prospect. We control approximately 75,000 gross (72,000 net) undeveloped acres within our Coyote Flats Prospect area. The prospect is located 15 to 25 miles northwest of Price, Utah, and is approximately 15 miles northwest

Table of Contents

of the Drunkard s Wash Field. Drunkard s Wash Field is expected to ultimately produce in excess of 1.2 Tcf of natural gas from the Cretaceous Ferron coals and sandstones. Data from drilling operations conducted on the Coyote Flats acreage during the 1950 s indicated gas shows from the Blackhawk and Emery coal seam intervals, and from the Ferron sand, the Mancos shales, and the Dakota sand. Our primary exploratory objectives at Coyote Flats are coal bed sequences in the Emery formation, and the Ferron sandstone. Emery coals are found across the majority of the lease position at depths from 2,000 to 5,000 feet, with estimated net coal thickness ranging from 20 to 130 feet. The Ferron sandstone is found at depths ranging from 5,000 to 6,500 feet on the acreage.

During the fourth quarter of 2002, we completed drilling a 100%-owned exploration well on the Coyote Flats Prospect. The well was designed to evaluate the Emery coals and the Ferron sandstone. The Scofield-Thorpe #22-41 well was drilled and cased to a total depth of 6,247 feet, before operations were suspended for the winter. During drilling, the well encountered 122 feet of Emery coal, in aggregate, from numerous coal seams. Eight of these coal seams have a thickness exceeding five feet, and the thickest coal seam is 22 feet. The Ferron section was drilled between 5,991 and 6,247 feet. Encouraging gas shows were encountered while drilling from several Emery coal seams and from fractured shales and sandstones in the Ferron section. Prima currently plans to seek a partner to undertake a nine-well Emery coal bed pilot project, immediately south of the Scofield-Thorpe #22-41 well, and is also presently working with various service companies to develop a completion plan for the Ferron section.

East Clear Creek Prospect. We own approximately 9,000 gross and net acres in the East Clear Creek Prospect, which is located approximately 15 miles west of Price, Utah. This prospect is one mile east of Clear Creek Field, which has produced 136 Bcf of natural gas from 16 wells drilled to the Cretaceous Ferron sandstone. Two miles east of Prima s prospect, at Gordon Creek Field, a third party recently completed six Ferron sandstone wells, three of which have been placed on line with initial production rates of 1.0 to 2.5 MMcf of gas per day. Our planned initial exploration well at East Clear Creek will target the Ferron sandstone at a depth of approximately 6,000 feet on a seismically defined structure. We are continuing to work with the U.S. Forest Service and the Bureau of Land Management on an EIS that is required before drilling permits will be issued on this prospect. We plan to drill a test well at East Clear Creek as soon as practicable after such permits are obtained, which we anticipate will be in late 2003 or in 2004.

Flat Canyon Prospect. Prima owns approximately 6,600 gross and net acres under its Flat Canyon Prospect, located in Emery County, Utah. Our acreage immediately offsets the Flat Canyon Field, which was discovered in 1952. The Flat Canyon Field has produced 9.6 Bcf of natural gas and 14,000 barrels of oil from six wells completed in the Cretaceous Ferron sandstones. We plan to test the Cretaceous Ferron and Dakota formations at depths between 6,500 and 7,500 feet on the prospect. A secondary objective at Flat Canyon is the Cretaceous Blackhawk coals, which are 10 to 30 feet thick, at depths of 1,100 to 2,500 feet. Prima is currently working with the U.S. Forest Service and the Bureau of Land Management to permit a well on this prospect. We anticipate drilling our first well on this prospect during 2003 or 2004.

Christmas Meadows Prospect. Prima owns or controls via farmout an aggregate 50% working interest in the Table Top Federal Unit, which consists of approximately 23,000 acres. The unit is located in Summit County, Utah, approximately 30 miles south of Evanston, Wyoming. The prospect objective is a seismically defined structural feature. The project has been delayed for several years while the U.S. Forest Service has been preparing an EIS and considering a revision of the forest plan for the area. Prima and its partners intend to cause a well to be drilled on the prospect shortly after the Forest Service completes this work, but no drilling activity is expected to take place during 2003.

Wyoming. Prima controls 407,000 gross, 249,000 net, undeveloped acres in the Powder River, Wind River, Green River, and Big Horn Basins in Wyoming. The more significant properties among these leaseholds are described below.

Merna Prospect. On the Merna Prospect, located in the Green River Basin in Sublette County, Wyoming, another operator drilled and set pipe at 13,900 feet on the Miller Federal #7-4 well during the second half of 2002. This well targeted the over-pressured Cretaceous Lance and Mesaverde formations, which are under extensive development on the Pinedale Anticline, located approximately 20 miles to the southeast. An affiliate of the operator installed a 36-mile natural gas pipeline to facilitate extended production testing of this well and future wells that might be drilled in the Merna area. The production testing of the Miller Federal #7-4 well was commenced but not completed during 2002.

Table of Contents

Planned completion operations on the well include fracture stimulations of ten prospective intervals, of which eight have been conducted through March 11, 2003. Establishment of commercial production in the Miller well is expected to be dependent upon results from the last two intervals to be tested. Project success may require encountering naturally fractured reservoirs or employing advanced completion techniques. The operator has indicated intentions of completing operations on the well during the first half of 2003, and has initiated activities to form an approximate 40,000-acre federal unit in the Merna area. Federal approval of a unit would likely require that two obligation wells be drilled over the ensuing twelve to eighteen months. In addition, a large regional 3-D seismic survey that was recently completed in the area encompassed a large portion of the Merna Prospect acreage. Prima owns a 3% overriding royalty and a 12.5% after-payout reversionary interest in this exploratory well, and retains working interests ranging from 12.5% to 50% in approximately 72,000 gross undeveloped acres in the Merna Prospect area.

Teakettle Prospect. We own working interests in 4,440 gross (2,220 net) acres in the Teakettle Prospect. This prospect is located in Sublette County, Wyoming, in the northern portion of the Green River Basin, approximately ten miles south of the large Jonah Field, which produces primarily from the over-pressured Upper Cretaceous Lance formation. During 2002, an extensive 3-D seismic survey was completed in the prospect area. We have not acquired this data, but anticipate that the seismic survey will stimulate exploration activities in the area during the coming year. At the present time, however, no drilling on the Teakettle Prospect is planned for 2003.

Hell s Half Acre Prospect. We own approximately 17,200 gross (5,500 net), undeveloped acres in the Hell s Half Acre Prospect, which is located in the eastern Wind River Basin, Natrona County, Wyoming. This prospect is a seismically defined structure located approximately ten miles southeast of Cave Gulch field. Prospective targets include the Fort Union, Lance, and deeper Frontier and Muddy formations. Several operators with leasehold interests in the prospect area have held discussions regarding the possibility of jointly drilling a deep test well. Although no such well has yet been proposed, we are hopeful that this project can commence by the end of 2003.

Proved Reserves

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Net proved reserves as of December 31, 2002 and 2001 were estimated by Prima s engineers and audited by Netherland, Sewell and Associates, Inc., independent petroleum engineers. Estimates as of December 31, 2000 were prepared or audited in part by Netherland, Sewell and Associates, Inc. and in part by Ryder Scott Company, independent petroleum engineers.

The table below sets forth the estimated quantities of net proved reserves attributed to our property interests at the end of each of the last three years, and the present value of estimated future net cash flows attributed to such reserves using prices in effect as of the respective year-end dates, held constant. The average net realizable prices used to estimate reserve quantities at the end of 2002, 2001, and 2000, respectively, were as follows: $2.64, $1.94, and $7.51 per Mcf for natural gas; and $31.30, $19.71, and $26.48 per barrel of oil. In accordance with Securities and Exchange Commission guidelines, projected future net cash flows from production of proved reserves were discounted by ten percent per annum to derive present values and the Standardized Measure of discounted future net cash flows after income taxes. The 10% discount factor is not necessarily a market rate, and present value, no matter what discount factor used, is materially affected by assumptions as to future prices and costs and timing of future production, which may prove to be inaccurate. For further information concerning estimated proved reserves and the discounted future net cash flows related to these reserves, see unaudited Supplementary Oil And Gas Information in Note 11 within the Notes to Consolidated Financial Statements.

	2002	2001	2000
Estimated proved natural gas reserves (Mcf)	87,440,000	115,222,000	154,172,000
Estimated proved oil reserves (barrels)	3,944,000	3,394,000	3,729,000
Present value of estimated future net cash flows, before future income tax expense	$128,843,000	$ 91,905,000	$576,052,000
Standardized measure of discounted future net cash flows	$ 91,279,000	$ 66,801,000	$371,121,000

Table of Contents

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing and amounts of development expenditures. Oil and gas reserve engineering should be recognized as a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate is a function of the quality of available engineering and geological data and interpretation, and judgment. Results of drilling, testing and production after estimates are prepared may justify revisions. Accordingly, reserve estimates are often materially different from the quantities of oil and natural gas that are ultimately produced. We are not currently aware of any developments subsequent to December 31, 2002 that we believe would warrant a significant upward or downward revision to our estimated proved reserves as of that date. Oil and natural gas prices have historically been volatile and are expected to continue to be so in the future. Changes in product prices affect the economic limits and, therefore, recoverable reserve quantities of oil and gas wells, as well as the present value of estimated future net cash flows and the standardized measure of discounted future net cash flows.

Since January 1, 2002, we have filed Department of Energy Form EIA-23, Annual Survey of Oil and Gas Reserves, as required of operators of domestic oil and gas properties. There are differences between the reserves as reported on Form EIA-23 and reserves as reported herein. Form EIA-23 requires that operators report on total proved developed reserves for operated wells only and that the reserves be reported on a gross operated basis rather than on a net interest basis.

Production

Our net natural gas production averaged 22,858 Mcf per day for the year ended December 31, 2002, compared to 25,416 Mcf per day for the year ended December 31, 2001 and 23,724 Mcf per day during the year ended December 31, 2000. Our net oil production averaged 1,022 barrels per day for the year ended December 31, 2002, compared to 1,181 barrels per day during the year ended December 31, 2001 and 1,202 barrels per day during the year ended December 31, 2000. The following table summarizes information with respect to our producing oil and gas properties for each of these periods.

	2002	2001	2000
Quantities sold:			
Natural gas (Mcf)	8,343,000	9,277,000	8,683,000
Oil (barrels)	373,000	431,000	440,000
Average sales price (including hedging effects):			
Natural gas (per Mcf)	$ 1.97	$ 3.60	$ 3.63
Oil (per barrel)	$ 25.14	$ 25.88	$ 29.29
Average production costs, including production taxes, per equivalent Mcf (1)	$ 0.49	$ 0.56	$ 0.53

(1) Oil production has been converted to a common unit of production (Mcf of natural gas) on the basis of relative energy content (one barrel of oil to six Mcf of natural gas).

Productive Wells

The following table summarizes our total gross and net productive wells, as of December 31, 2002.

	Productive Wells			
	Oil		Gas	
	Gross(1)	Net(2)	Gross(1)(3)	Net(2)(3)
Operated:				
Colorado	9	8.5	399	367.9
Wyoming	0	0.0	208	186.8
Non-operated:				
Colorado	0	0.0	19	8.1
Utah	0	0.0	1	0.4
Wyoming	0	0.0	39	3.6

Total(4)	9	8.5	666	566.8

Additionally, we own royalty interests in 52 gross wells that are not included in the above table.

(1) A gross well is a well in which a working interest is held. The number of gross wells is the total number of wells in which a working interest is owned.

(2) A net well is deemed to exist when the sum of fractional ownership interests in gross wells equals one. The number of net wells is the sum of the fractional working interests owned in gross wells expressed as whole numbers and fractions thereof.

(3) Includes 107 gross (95.6 net) CBM wells in Wyoming that were shut-in awaiting hook-up at year-end.

(4) Wells are classified as oil wells or gas wells according to predominate production stream. Multiple completions (28 wells) are counted as one well.

Developed and Undeveloped Acreage

At December 31, 2002, we held leased acreage as set forth below:

	Developed Acreage(1)		Undeveloped Acreage(2)	
Location	Gross(3)	Net(4)	Gross(3)	Net(4)
Big Horn Basin	0	0	101,000	26,000
Denver Basin	18,100	15,500	13,000	12,000
Green River Basin	0	0	88,000	39,000
Powder River Basin	11,500	10,100	177,000	159,000
Uinta Basin	0	0	105,000	102,000
Wind River Basin	1,200	150	41,000	25,000
Other basins	1,500	50	18,000	15,000
Total	32,300	25,800	543,000	378,000

(1) Developed acres are acres spaced or assigned to productive wells.

(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

(3) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(4) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. We have generally been able to obtain extensions of the primary terms of our federal leases for the period that we have been unable to obtain drilling permits due to a pending EIS. The following table sets forth the expiration periods of the gross and net acres subject to leases summarized in the table of undeveloped acreage, unless such leases are currently held by production from a portion of the lease that has been developed.

	Acres Expiring	
	Gross	Net
Twelve Months Ending:		
December 31, 2003	15,000	9,000

December 31, 2004	57,000	27,000
December 31, 2005	90,000	57,000
December 31, 2006	35,000	34,000
December 31, 2007	40,000	26,000
December 31, 2008 and later	243,000	181,000
	480,000	334,000

Table of Contents

Drilling Activities

Certain information with regard to our drilling activities for the years ended December 31, 2002, 2001 and 2000 is set forth below:

	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	55	50.1	123	121.3	178	176.7
Dry	0	0.0	0	0.0	3	2.0
	55	50.1	123	121.3	181	178.7
Exploratory:						
Productive	18	11.0	14	14.0	5	4.9
Dry	0	0.0	2	0.3	0	0.0
	18	11.0	16	14.3	5	4.9
Total:						
Productive	73	61.1	137	135.3	183	181.6
Dry	0	0.0	2	0.3	3	2.0
	73	61.1	139	135.6	186	183.6

Present Activities

Subsequent to December 31, 2002, through March 11, 2003, we have participated in the completion of two gross (1.9 net) wells and the restimulation of 6 gross (5.7 net) wells in the Denver Basin, all of which have been placed on or restored to production. During this same period, we continued our participation in two non-operated (0.26 net) wells in the Cave Gulch area. One well is waiting on completion, and the other well may be abandoned due to mechanical problems.

Natural Gas and Oil Marketing and Trading

Prima s marketing and trading activities may include marketing our own production, marketing the production of other owners in wells that we operate, and the purchase and resale of third-party owned production. At times, we use financial instruments to hedge the price of a portion of Prima s production or production of others that we have committed to purchase for resale.

Natural Gas. The terms and conditions of our natural gas sales contracts vary as to price, quantity, term and other conditions, but in general follow 30-day spot or day-to-day prices as posted. We occasionally sell gas at a fixed price for periods greater than 30 days, as an effective price hedge, but had no such fixed-price sales arrangements in effect at year-end 2002. We have a significant purchaser of our natural gas in the Denver Basin, Duke Energy Field Services, LLC, that accounted for 33% of our total consolidated revenues in 2002. Duke is not affiliated with Prima and, while loss of Duke as a customer might have a material adverse effect on our business, we believe we could arrange to sell our gas to alternate customers on reasonably comparable terms.

We currently have four gathering agreements in effect to get our gas from the wellhead into high-pressure header systems or interstate pipelines. These include one in the Denver Basin, one in the Wind River Basin, and two in the Powder River CBM play. We have not, however, contracted for downstream transportation on a firm basis. As such, we have no liability to pay reservation (demand) charges for header or pipeline capacity, but we also have no assurance that our gas will flow every day, and we are also at risk that regional imbalances between gas supply and pipeline capacity will unfavorably impact the gas prices that we realize for our production. No significant curtailments of gas production occurred in 2002, but limited pipeline capacity did create conditions during several months in which the netback price that we received for our natural gas was significantly below prices being paid for gas elsewhere in the country.

At times, we have also engaged in purchasing and re-selling third-party gas within our areas of operations. These arrangements typically provide for the purchase of natural gas at a known price or index, with a corresponding sale at

Table of Contents

a net margin. However, from time to time we may have open purchase or sale commitments without corresponding contracts, which could result in losses. Prima s Chief Executive Officer reviews such opportunities before commitments are made, and we closely monitor the mark-to-market gains or losses of such positions. We had no purchase-for-resale trading obligations outstanding at the end of 2002 and had entered into no commitments after year-end 2002 through March 11, 2003. In 2002, total revenues from the sale of Prima s natural gas production, including related hedging effects, were $16,413,000, or 64% of oil and gas sales and 52% of consolidated total revenues.

Oil. Our oil production is sold under a number of contracts at negotiated prices determined by quality, location, and prevailing market indices. The contracts are generally month-to-month in duration. Our point of sale for crude oil is typically at the tank battery near the well, where oil is picked up and trucked by the purchaser to pipelines or refineries. During 2002, one of the purchasers of our oil, Valero Energy Corporation, accounted for approximately 29% of our total consolidated revenues for the year. We are not affiliated with Valero, and we believe that we could sell our crude oil to other purchasers on comparable terms should we lose Valero as a customer. In 2002, revenues from the sale of Prima s crude oil, including related hedging effects, totaled $9,372,000, or 36% of oil and gas sales and 29% of consolidated total revenues.

Risk Management. We sometimes utilize commodity futures, over-the-counter swaps, or similar derivatives, to mitigate risks related to the volatility of oil and gas prices. Such transactions can also be used to protect against the risk of an expanding NYMEX to CIG basis differential, which can occur when natural gas supplies exceed pipeline capacity out of the Rocky Mountain region or due to other factors, such as regional weather differences. During 2002, we entered into derivatives contracts covering approximately 56% of our natural gas production and 25% of our crude oil production. A portion of these contracts did not meet all of the conditions required for utilization of hedge accounting, but were nevertheless viewed by us as providing considerable revenue protection in the event of declining oil and gas prices or widening basis differentials. Approximately 6% of our natural gas production and 25% of our crude oil production in 2002 were covered by derivatives contracts that qualified for hedge accounting. See Item 7A, Quantitative and Qualitative Disclosures about Market Risk, below for additional disclosures relating to derivatives, including our open derivative positions as of March 18, 2003.

<u>Title to Oil and Gas Properties</u>

As is customary in the oil and gas industry, we typically conduct only a preliminary title examination at the time that we acquire leases of properties believed to be suitable for drilling operations. Prior to the commencement of drilling operations, however, we engage independent attorneys to conduct a thorough title examination of drill site tracts. Once production from a given well is established, a division order title report is prepared, which indicates the proper parties and percentages for payment of production proceeds, including royalties. We believe that titles to Prima s leasehold properties are good and defensible in accordance with standards generally acceptable in the oil and gas industry.

Oilfield Services

We conduct our oilfield services business under the names of Action Oilfield Services in Colorado and Action Energy Services in Wyoming.

Action Oilfield Services. Action Oilfield Services (AOS) has been active in the Denver Basin since 1986, operating out of a field office and yard near LaSalle, Colorado. AOS owns various well servicing equipment including completion rigs, a swab rig, tractor trailer rigs for water hauling, and oilfield rental equipment, such as pumps, tanks and blowout preventers. During 2002, we experienced high utilization rates for our people and equipment due to strong demand for services for well recompletions, re-works and drilling in the area. We intend to continue with our well servicing activities in the Denver Basin, and will seek opportunities to profitably expand the business. AOS provides services for Prima as well as third-party operators in the area. During 2002, 17% of AOS s revenues were from activities performed for Prima. AOS fees and costs associated with providing services to Prima are eliminated in the consolidated financial statements. Third-party revenues recorded by AOS in 2002 totaled $6,470,000, or 20% of our consolidated revenues.

Table of Contents

Action Energy Services. We formed Action Energy Services (AES) in the first quarter of 1999, to conduct CBM well drilling and servicing activities in the Powder River Basin. AES leases an office and yard in Gillette, Wyoming. In addition to providing well services, AES has six CBM drilling rigs. During 2002, activity levels in the Powder River Basin CBM play declined, due to weak regional gas prices and limited availability of drilling permits on federal lands due to the pending status of the EIS. As a result, we experienced a decline in the utilization rates for our people and equipment. However, we believe that activity levels in the area will increase as the underlying causes of the slowdown are addressed, and we intend to continue to conduct both drilling and well servicing operations in the Powder River Basin, on behalf of both Prima and unaffiliated third parties. During 2002, 28% of AES s revenues were services conducted for Prima, and these revenues and the related costs have been eliminated in consolidation. AES s third-party revenues were $1,856,000 in 2002, accounting for 6% of our consolidated revenues.

Gas Gathering Services

Arete Gathering Company, LLC. We formed Arete Gathering Company, LLC (Arete) in the third quarter of 2000 to provide gas compression and gathering services for the CBM play in the Powder River Basin. Arete installed its first gathering system in Prima s Stones Throw Area between mid-2000 and the first quarter of 2001. These assets were included in the Stones Throw sale transaction consummated in March 2002. No other gathering systems have been installed by Arete to date.

We will evaluate future opportunities to build gathering and compression systems in the Powder River Basin based on the size and estimated reserve potential of our acreage blocks, proximity to header systems and pipelines, competitive options provided by third parties, and other factors affecting the economics of each project. In areas where Prima does not have a significant contiguous acreage block, or where third party gathering systems have already been installed, we will generally elect not to have Arete build a gathering system. Where Arete does install gathering and compression infrastructure, we will seek to provide such services to third parties to benefit from economies-of-scale and enhance our overall economic returns.

Other Properties, Equipment and Real Estate

We lease 15,840 square feet of office space in Denver, Colorado, at an escalating annual cost that averages approximately $275,000 over the seven-year term that commenced December 1, 2000. We own office furniture and equipment at this location with a net book value of $199,000 at December 31, 2002.

We lease office space with yard and shop facilities in Gillette, Wyoming. The shop, office building and yard facilities located on the land are used for our Powder River Basin field and oilfield service operations. Net book value of our oilfield service equipment, office furniture and equipment and leasehold improvements at this location was $2,146,000 on December 31, 2002.

We own 160 acres of land with no mineral rights in Weld County, Colorado near LaSalle, Colorado. The shop, office building and yard facilities located on the land are used for our Denver Basin field and oilfield service operations. Net book value of our oilfield service equipment, office furniture and equipment and land and buildings at this location was $2,494,000 on December 31, 2002.

We own approximately ten acres of surface land with no mineral rights on the western side of Greeley, Colorado. The land was acquired in March 2001 in exchange for minor undeveloped mineral rights. This ten-acre parcel is part of a planned 760-acre commercial and office park development. We plan to hold this land, which had a net book value of $944,000 at the end of 2002, for future sale, exchange or development.

Prima is a 6% limited partner in a real estate limited partnership that owns approximately 22 acres of undeveloped land in Phoenix, Arizona for investment and capital appreciation. The book value of this partnership interest was $257,000 at December 31, 2002.

Table of Contents

Competition.

All of our businesses are highly competitive. Our oil and natural gas operations encounter strong competition from major oil and gas companies, independent operators and others. Competition is particularly intense with respect to the acquisition of desirable undeveloped and developed oil and gas properties. The principal competitive factors in the acquisition of oil and gas properties include the availability and quality of staff and data necessary to identify, investigate and purchase such properties, and the financial resources necessary to acquire and develop such assets. Many of our competitors have appreciably greater financial, technical and other resources and have more experience in the exploration for and production of oil and natural gas than we have.

Competition in oilfield services traditionally involves such factors as price, efficiency, condition of equipment, availability of labor and equipment, reputation and customer relations. Some of our competitors in the oilfield services business are substantially larger than we are and have appreciably greater financial and other resources. The competitive environment within which we operate is uncertain and extremely price oriented. Likewise, other businesses that we may participate in, including gas marketing and trading, and gas gathering and processing, are characterized by significant competition from companies with greater financial resources than Prima and, potentially, better information regarding markets than we have access to.

Regulation

Our businesses are subject to extensive federal, state and local laws and regulations on the exploration for and the development, production and marketing of oil and gas, and environmental and safety matters.

Regulation of Drilling and Production. Oil and gas operations are subject to various types of regulation by state and federal agencies. Legislation affecting the oil and gas industry is under constant review for amendment or expansion. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. The regulatory burden on the oil and gas industry increases the costs of doing business. States in which Prima conducts its gas and oil activities regulate drilling activities and the production and sale of natural gas and crude oil. Such regulations establish and implement requirements for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and gas resources. In addition, states may regulate the rate of production and establish maximum daily production allowables for wells on a market demand or conservation basis. In the past, the federal government has regulated the prices at which oil and gas could be sold. Sales prices of oil and gas are not currently regulated, but there is no assurance that such regulatory treatment will continue indefinitely into the future. Congress could re-enact price controls or other regulations in the future.

Environmental Matters. Prima is subject to extensive federal, state and local environmental laws and regulations that, among other things, regulate the discharge or disposal of materials or substances into the environment and otherwise are intended to protect the environment. Numerous governmental agencies issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial administrative, civil and/or criminal penalties and in some cases injunctive relief for failure to comply. Some laws, rules and regulations relating to the protection of the environment may, in certain circumstances, impose strict liability for environmental contamination. Such laws render a person or company liable for environmental and natural resource damages, cleanup costs and, in the case of oil spills in certain states, consequential damages without regard to negligence or fault.

Other laws, rules and regulations may require the rate of oil and natural gas production to be below the economically optimal rate or may even prohibit exploration or production activities in environmentally sensitive areas. In addition, state laws often require some form of remedial action such as closure of inactive pits and plugging of abandoned wells to prevent pollution from former or suspended operations. Legislation has been proposed and continues to be evaluated in Congress from time to time that would reclassify certain oil and gas exploration and production wastes as hazardous wastes. This reclassification would make such wastes subject to much more stringent and expensive storage, treatment, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant adverse impact on operating costs for the oil and gas industry, including Prima. Initiatives to further regulate the disposal of oil and gas wastes are also proposed in certain states from time to time and may include initiatives at county, municipal and local government levels. These various initiatives could have a similar adverse impact on our operations. The regulatory burden on the oil and natural gas industry increases its cost and risk of doing business and consequently affects its profitability.

Compliance with these environmental requirements, including financial assurance requirements and the costs associated with the cleanup of any spill, could have a material adverse effect upon Prima s capital expenditures, earnings or competitive position. We believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse impact on our competitiveness. Nevertheless, changes in environmental laws and regulations have the potential to adversely affect Prima s operations. For example, the federal Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), also known as the Superfund law, imposes liability, without regard to fault (i.e. strict and joint and several liability) or the legality of the original conduct, on certain classes of persons with respect to the release of a hazardous substance into the environment. These persons include the current or prior owner or operator of the disposal site or sites where the release occurred and companies that transported, disposed or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for the federal or state government to pursue such claims. It is also not uncommon for neighboring landowners and other third parties to file claims for personal injury or property or natural resource damages allegedly caused by the hazardous substances released into the environment. Under CERCLA, certain oil and gas materials and products are, by definition, excluded from the term hazardous substances. However, certain federal courts have held that some wastes associated with the production of crude oil may be classified as hazardous substances under CERCLA.

Similarly, under the federal Resource, Conservation and Recovery Act of 1976, as amended (RCRA), which governs the generation, treatment, storage and disposal of solid wastes and hazardous wastes, certain exploration and production wastes are exempt from the definition of hazardous wastes. This exemption continues to be subject to judicial interpretation and increasingly stringent state interpretation. During the normal course of its operations, Prima generates or has generated in the past exempt and non-exempt wastes, including hazardous wastes that are subject to RCRA and comparable state statutes and implementing regulations. The federal Environmental Protection Agency (EPA) and various state agencies continue to promulgate regulations that limit the disposal and permitting options for certain hazardous and non-hazardous wastes.

The state of Colorado, where a significant portion of Prima s producing properties are located, amended its statute concerning oil and natural gas development in 1994 to provide the Colorado Oil & Gas Conservation Commission (the COGCC) with enhanced authority to regulate oil and gas activities to protect public health, safety and welfare, including the environment. The COGCC has implemented several rules pursuant to these statutory changes concerning groundwater protection, soil conservation and site reclamation, setbacks in urban areas and other safety concerns, and financial assurance for industry obligations in these areas. To date, these rule changes have not adversely affected Prima s operations, as the COGCC is required to enact cost-effective and technically feasible regulations. However, there can be no assurance that, in the aggregate, these and other regulatory developments will not increase the cost of operations in the future.

Also in Colorado, a number of city and county governments have enacted oil and gas regulations. These ordinances increase the involvement of local governments in the permitting of oil and gas operations, and impose additional restrictions or conditions on the conduct of operations so as to reduce their impact on the surrounding community. Accordingly, these local ordinances have the potential to delay and increase the cost of drilling, refracing and recompletion operations.

In Prima s CBM gas production operations in the Powder River Basin, we typically bring naturally occurring groundwater to the surface as a by-product of the production of methane gas. The disposition of this water is regulated by federal and state authorities. To-date, most of the water produced from Prima s wells has been discharged on the surface, in accordance with permits obtained in compliance with federal and state statutes and regulations. However, water disposal alternatives are currently under review by federal and state regulatory authorities and future development of properties in the area may require utilization of other methods. Implementation of such alternatives, potentially including but not limited to, construction of evaporation ponds near the well site and treatment of the water, could add delays and costs in developing and operating these properties. Prima may also explore on or acquire properties in other areas where disposal of produced water will be subject to regulation by federal and state authorities.

A significant portion of Prima s leasehold interests in the Powder River Basin in Wyoming, the Uinta Basin in Utah, and elsewhere in the Rocky Mountain region is federal acreage where mineral rights, and sometimes surface ownership as well, are managed by the Bureau of Land Management (the BLM). Drilling and development of federal minerals and construction activities on federal surface are subject to the National Environmental Policy Act (NEPA). The BLM has delayed drilling on a substantial portion of the federal oil and gas leases held by Prima, as well as those of other operators in these areas, pending completion of environmental impact statements or assessments under NEPA. Delays in obtaining access to these lands, and conditions imposed on development of the properties, may affect the value of Prima s reserves and prospects.

In some circumstances, our operations involve the use of gas-fired compressors to transport collected gas. Operation of these compressors is subject to federal and state regulations for the control of air emissions.

The Federal Water Pollution Control Act (FWPCA) imposes restrictions and strict controls regarding the discharge of produced waters and other oil and gas wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters. The FWPCA and analogous state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of oil and other hazardous substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. State water discharge regulations and the federal National Pollutant Discharge Elimination System permits applicable to the oil and gas industry generally prohibit the discharge of produced water, sand and some other substances into coastal waters. The costs to comply with zero discharges mandated under federal and state law have not had a material adverse impact on Prima s financial condition and results of operations. Some oil and gas exploration and production facilities are required to obtain permits for their storm water discharges. Costs may be incurred in connection with treatment of wastewater or developing storm water pollution prevention plans.

The Oil Pollution Act of 1990 (OPA) imposes regulations on responsible parties related to the prevention of oil spills and liability for damages resulting from spills in waters of the United States. A responsible party includes the owner or operator of an onshore facility, vessel or pipeline, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns strict, joint and several liability to each responsible party for oil removal costs and a variety of public and private damages, including natural resource damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation, or if the party fails to report a spill or to cooperate fully in the cleanup. Even if applicable, the liability limits for onshore facilities require the responsible party to pay all removal costs, plus up to $350 million in other damages. Few defenses exist to the liability imposed by OPA. Failure to comply with ongoing requirements or inadequate cooperation during a spill event may subject a responsible party to administrative civil or criminal enforcement actions.

Operating Hazards and Insurance

The oil and natural gas business involves a variety of operating risks, including fires, explosions, blowouts, environmental hazards and other potential events that could adversely affect our ability to conduct operations or cause us to incur substantial losses. Such impairment or losses could reduce or eliminate funds available for exploration,

Table of Contents

exploitation or acquisitions, or result in loss of properties. In accordance with customary industry practices, we maintain insurance against some, but not all, potential risks and losses. We do not carry business interruption insurance. For some risks, we may elect not to obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable at a reasonable cost. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect us.

Employees and Offices

As of December 31, 2002, we had 130 full-time employees, including 37 in our Denver office and 93 in district and field offices. Of the district and field employees, 18 were employed in Prima s lease and well management operations and 75 were employed with our oilfield service operations. We also contract for the services of independent consultants involved in land, geology, engineering, accounting, regulatory affairs, and other disciplines as needed. We believe that Prima s relations with its employees are good.

Prima s principal executive offices are located at 1099 18th Street, Suite 400, Denver, Colorado 80202.

Available Information

Our website address is www.primaenergy.com. We make available free of charge through our internet website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed with or furnished to the SEC under applicable securities laws as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. Our website information is not incorporated by reference into this Annual Report on Form 10-K.

ITEM 3. LEGAL PROCEEDINGS

We are a party to various legal proceedings arising in the ordinary course of its business. As of the date of the filing of this report, none of these is expected to have a material adverse impact on our financial position or results of operations.

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

No matters were submitted to a vote of our security holders during the quarter ended December 31, 2002.

Cautionary Statement for the Purposes of the Safe Harbor
Provisions of the Private Securities Litigation Reform Act of 1995

We are including the following cautionary statement to take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statement made by, or on behalf of, Prima. The factors identified in this cautionary statement are important factors (but not necessarily all of the important factors) that could cause actual results to differ materially from those expressed in any forward-looking statement made by, or on behalf of, Prima. Where any such forward-looking statement includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that, while we believe such assumptions or bases to be reasonable and make them in good faith, assumed facts or bases almost always vary from actual results, and the differences between assumed facts or bases and actual results can be material, depending upon the circumstances. Where, in any forward-looking statement, Prima or its management expresses an expectation or belief as to the future results, such expectation or belief is expressed in good faith and believed to have a reasonable basis, but there can be no assurance that the statement of expectation or belief will result, or be achieved or accomplished. We do not undertake to update, revise or correct any of the forward-looking information. Taking into account the foregoing, the following are identified as important risk factors that could cause actual results to differ materially from those expressed in any forward-looking statement made by, or on behalf of, Prima:

Table of Contents

Volatility of Oil and Natural Gas Prices. 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 our control. To the extent that oil and gas prices decline, our revenues, cash flows, earnings and operations are adversely impacted. Further, in adversely affecting our cash flows and access to capital, low oil and gas prices could reduce our ability to replace production and grow. Because of the dynamism of, and number of influences on, commodity markets, we cannot accurately predict future oil and natural gas prices.

Uncertainty of Oil and Natural Gas Reserve Estimates. Estimates of our proved reserves and related future net revenues are based on engineering reports prepared by our engineers and audited by independent engineers. These estimates are based on several assumptions that the Securities and Exchange Commission requires oil and natural gas companies to use, including that oil and natural gas prices in effect as of the end of the year remain constant. Such estimates are inherently imprecise indications of future net revenues. Actual future production, revenues, production taxes, operating expenses, and development costs may vary substantially from estimates. In addition, our reserves might be subject to upward or downward adjustment based on future production, results of future exploration and development, prevailing oil and natural gas prices and other factors.

Risks of Oil and Natural Gas Exploration, Development and Production. The search for oil and natural gas often results in unprofitable efforts, not only from dry holes, but also from wells that, though productive, do not produce oil or natural gas in sufficient quantities to return a profit on the costs incurred. No assurance can be given that our exploration, development and acquisition activities in the future will result in the addition of any oil or natural gas reserves that will be commercially productive. In addition, the costs of drilling, completing and operating wells are often uncertain, and drilling may be delayed or canceled as a result of many factors, including unacceptably low oil and natural gas prices, availability of drilling rigs, oil and natural gas property title problems, government regulation, inclement weather conditions and financial instability of third-party operators and working interest owners.

Need to Replace Reserves. Our future success depends to a significant degree upon our ability to continue to find, develop or acquire additional oil and gas reserves that are economically recoverable. Unless we replace the reserves that we produce through successful exploration, exploitation or acquisition, our proved reserves will decline. Additionally, approximately 24% of our total proved reserves at December 31, 2002 were undeveloped. Recovery of such reserves will require significant capital expenditures and successful drilling and/or recompletion operations. There can be no assurance that we will be successful in our future efforts to develop our proved reserves or replace our production.

Acquisitions Risks. We continually evaluate opportunities for property or corporate acquisitions that could enhance our business. Acquisitions of properties or companies involve assessments of several factors, including recoverable reserves, future oil and gas prices, future capital and operating costs, and potential environmental and other liabilities. Such assessments incorporate estimates and projections that are inherently imprecise and uncertain. In connection with any future acquisitions, we would intend to perform a review of the subject properties consistent with industry practices. However, such review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every property and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or be in different geographic locations than our existing properties. While it is our current intention to continue to concentrate on acquiring properties with development, exploitation and exploration potential located in our core operating areas, we cannot assure you that in the future we will not decide to pursue acquisitions or properties located in other geographic regions. To the extent that such acquired properties are substantially different than our existing properties, our ability to efficiently realize the economic benefits of such transactions may be limited. We may not be able to successfully integrate future property or corporate acquisitions. We seek to make selective niche acquisitions of oil and gas properties, and we will pursue corporate acquisitions that we believe will be accretive. However, integrating acquired properties and businesses involves a number of special risks. These risks include the possibility that management may be distracted from normal business concerns by the need to integrate operations and

Table of Contents

systems and in retaining and assimilating additional employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results.

Dependence On Transportation Facilities Owned by Others. Our business depends on transportation facilities owned by others. The marketability of our oil and gas production, and the net prices received for such production, depend in part on the availability, proximity and capacity of pipeline systems owned by third parties. The unavailability of, or lack of available capacity on, these systems and facilities could result in curtailment of production, the delay or discontinuance of development plans for properties, and/or reduced price realizations for production. Although we have some contractual control over the transportation of our product, material changes in these business relationships or market conditions could significantly affect our operations. Federal and state regulation of oil and gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

Derivatives. Part of Prima s business strategy is to periodically use commodity futures contracts, including price and basis swaps, collars and options, to mitigate the impact of the volatility of oil and natural gas prices on a portion of our production and gas marketing activities. In certain circumstances, significant reductions in production caused by unforeseen events, or insufficient correlation between a derivative and the market prices that we receive for our production, could require us to make payments under such agreements even though such payments are not offset by revenues from production. To reduce these risks, we generally enter into derivatives for only a portion of our projected production and utilize derivatives closely correlated with our price realizations unless we believe market conditions to fix basis spreads are unfavorable. At times, however, we may decide to enter into derivatives contracts for volumes that match or exceed our projected total production, or contracts that increase, rather than decrease, our exposure to a decline in oil and gas prices or expansion of basis differentials. We would consider establishing such positions if our analyses lead us to believe that prices are likely to move in a manner that would generate gains from the positions. Derivative positions for volumes greater than our expected production, or which would increase our exposure to a decline in oil and gas prices or expansion of basis differentials, would be speculative and would be limited in size to an amount that, in management s judgment would not be material to our balance sheet taken as a whole, but they might have a significant positive or negative impact on reported net earnings.

Derivatives positions might also prevent Prima from receiving the full advantage of increases in oil or natural gas prices, and could expose us to risk of financial loss should a counterparty to one or more of our derivatives contracts fail to perform. The terms of our hedging agreements may also require that we furnish cash collateral, letters of credit or other forms of performance assurance in the event that mark-to-market calculations result in settlement obligations by us to the counterparties. Such performance assurance could encumber our liquidity and capital resources. In accordance with Statement of Financial Accounting Standards (SFAS) No. 133, we record the fair market value of each derivative position as an asset or liability. Changes in the fair market value of our derivatives positions could result in significant fluctuations in net income and stockholders equity from period to period

Capital Requirements. We anticipate continuing to make substantial expenditures to find, develop, acquire and produce oil and gas reserves. We expect to have sufficient cash provided by operating activities and from available net working capital to fund planned capital expenditures in 2003. However, we have not established a line of credit to provide additional capital to respond to new opportunities. While we believe that we could arrange for borrowings or issuance of securities to fund such opportunities, should lower oil and gas prices or operating difficulties result in our cash flow from operations being less than expected or if capital markets were to deteriorate, we may be unable to obtain additional funds to expand our business.

Demand For Oilfield Services. Our oilfield services operations are dependent on the level of demand in our operating markets. Both short- and long-term trends in oil and gas prices affect demand. Because oil and gas prices are volatile, the level of demand for our services can also be volatile. Although we utilize our service companies in our oil and gas operations, the substantial majority of the demand for their services is dependent on third parties. In addition to oil and gas prices, other factors that can influence activity levels for our oilfield service operations include competition, our reputation, availability of labor, and weather. Further, activity levels in the areas in which we operate can be impacted by the attractiveness of oil and gas investment opportunities in the area relative to other oil and gas investment opportunities.

Table of Contents

Competition. We compete with numerous other companies and individuals in virtually all facets of our business, including many that have significantly greater resources than we do. Such competitors may be able to pay more than Prima for desirable assets and experienced personnel. Many competitors may also have greater technical resources and increased staff to evaluate and develop investment opportunities than do we. Domestic oil and gas companies must also compete with imported oil and natural gas, coal, nuclear energy, hydroelectric power and other forms of energy.

Operating Hazards and Uninsured Risks. The oil and gas business involves a variety of operating risks, including risks of fire, explosions and well blow-outs, as well as risks associated with production, marketing, and general economic conditions. We maintain insurance against some, but not all, of these risks, any of which could result in substantial losses. There can be no assurance that insurance carried would be adequate to cover any losses or exposure to liabilities. There also can be no assurance that in the future insurance will continue to be available at premium levels that justify its purchase, or whether it will be available at all.

Government Regulation. Federal, state and local governments extensively regulate all aspects of the oil and gas industry. Regulations govern such things as drilling permits, environmental protection and pollution control, spacing of wells, the unitization and pooling of properties, water use and disposal, production, royalty rates and various other matters including taxation. As an example, our exploration and development plans for our Powder River Basin CBM properties are dependent upon the timing, content and implementation of a pending record of decision by the Bureau of Land Management concerning an environmental impact statement covering CBM development in the area. Additionally, the Colorado Oil & Gas Conservation Commission has promulgated regulations to protect ground water, conserve soil, provide for site reclamation, ensure setbacks in urban areas, generally promote safety concerns and mandate financial assurance for companies in the industry. Oil and gas industry legislation and administrative regulations are periodically changed for a variety of political, economic and other reasons. These regulations may substantially increase the cost of doing business and sometimes prevent or delay the commencement or continuance of any given exploration or development project and may adversely affect the economics of capital projects. At the present time, we cannot predict what effects current and future proposals or changes in existing laws or regulations will have on operations, estimates of oil and natural gas reserves, or future net revenues. The costs of complying, monitoring compliance and dealing with the agencies that administer these regulations can be significant. We could also be subject to substantial penalties if we fail to comply with any regulation.

Environmental Regulation. Our operations are subject to complex and frequently changing environmental laws and regulations adopted by federal, state and local governmental authorities. New laws or regulations, or changes to current practices, could have a material adverse effect on our business. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between state and federal agencies. We could face significant liabilities to the government and third parties for discharges of oil, natural gas or other pollutants into the air, soil or water, and we might need to spend substantial amounts on investigations, litigation and remediation. We could face material indemnity claims with respect to properties we own or have owned. We cannot be sure that existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced or altered in the future, will not materially adversely affect our results of operations and financial condition.

Key Personnel. We depend on the continued services of our executive officers and other key employees. Loss of the services of any of these people could have a material adverse effect on our operations. We currently do not have employment agreements with any of our key employees, including Richard H. Lewis, who serves as Prima s Chief Executive Officer, President and Chairman of the Board of Directors.

Table of Contents

PART II

ITEM 5. MARKET FOR THE REGISTRANT S COMMON STOCK AND RELATED STOCKHOLDER MATTERS

(a) Market Information

Prima s common stock trades on the Nasdaq National Market under the symbol PENG. The following table sets forth the Nasdaq high and low sales prices for our common stock for each quarterly period during the Company s years ended December 31, 2002 and 2001.

Year Ended December 31, 2002	HIGH	LOW
Quarter Ended March 31, 2002	$26.46	$19.10
Quarter Ended June 30, 2002	26.34	20.23
Quarter Ended September 30, 2002	23.00	15.70
Quarter Ended December 31, 2002	24.49	20.38
Year Ended December 31, 2001		
Quarter Ended March 31, 2001	$38.94	$25.25
Quarter Ended June 30, 2001	32.17	22.81
Quarter Ended September 30, 2001	27.69	19.99
Quarter Ended December 31, 2001	25.48	19.50

The above quotations are from sources believed to be reliable. They do not include any retail mark-ups, mark-downs or commissions and may not represent actual transactions. On March 11, 2003, the closing sale price for our common stock was $18.75 per share.

(b) Holders of Record

Our common stockholders of record at March 11, 2003 totaled 831.

(c) Dividends

Holders of common stock are entitled to receive such dividends as may be declared by our Board of Directors. No cash dividends were declared or paid in 2002, 2001 or 2000. Future cash dividends, if any, will be evaluated based among other things, on our operating results, capital requirements and financial condition at the time.

Table of Contents

(d) Securities Authorized for Issuance Under Equity Compensation Plans

The following table includes information regarding Prima s equity compensation plans as of the year ended December 31, 2002:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	1,083,825	$ 14.15	1,181,475
Equity compensation plans not approved by security holders			
Total	1,083,825	$ 14.15	1,181,475

Issuance of Unregistered Securities

During 2002, Prima granted options to acquire a total of 194,000 common shares that were not registered under the Securities Act of 1933, as amended. The options were granted as follows:

Options to acquire a total of 22,500 common shares were granted to directors of Prima under the terms of Prima s Non-Employee Directors Stock Option Plan.

Options to acquire a total of 171,500 common shares were granted to certain key employees of Prima under the terms of Prima s 2001 Stock Incentive Plan.

No underwriter was involved in any of the transactions and Prima paid no sales commissions, fees, or similar compensation to any person in connection with the issuance of the options. In each case, the options granted become exercisable in 20% annual increments commencing on the first anniversary of the grant date. Prima filed S-8 registration statements with the Securities and Exchange Commission on November 7, 2002 for the Prima Energy Corporation Non-Employee Directors Stock Option Plan and the Prima Energy Corporation 2001 Stock Incentive Plan.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth a summary of selected consolidated financial data. This data should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and the Consolidated Financial Statements and notes thereto.

	Years Ended December 31,				
	2002	2001	2000	1999	1998
Income Statement Data:					
Revenues:					
Oil and gas sales	$ 25,785	$ 44,548	$ 44,437	$ 20,644	$ 16,612
Gains (losses) on derivative instruments, net	(2,918)	6,435			
Oilfield services	8,326	8,090	6,278	4,974	4,148
Trading revenues				2,318	3,956
Interest, dividend and other	597	1,214	1,464	1,286	4,378
	31,790	60,287	52,179	29,222	29,094
Expenses:					
Depletion of oil and gas properties	9,710	9,190	6,150	4,650	6,260
Depreciation of other property	1,291	1,369	1,054	817	616
Lease operating expense	3,076	3,295	2,623	2,012	2,041
Ad valorem and production taxes	2,116	3,344	3,421	1,765	1,272
Oilfield services	6,287	5,482	4,585	3,377	2,701
General and administrative	3,255	3,559	2,916	1,712	1,143
Impairment of natural gas swap		241			
Trading costs				2,827	3,936
	25,735	26,480	20,749	17,160	17,969
Income before income taxes and cumulative effect of change in accounting principle	6,055	33,807	31,430	12,062	11,125
Provision for income taxes	825	10,650	9,535	3,035	3,060
Net income before cumulative effect of change in accounting principle	5,230	23,157	21,895	9,027	8,065
Cumulative effect of change in accounting principle		611			
Net income	$ 5,230	$ 23,768	$ 21,895	$ 9,027	$ 8,065
Basic net income per share before cumulative effect adjustment	$ 0.41	$ 1.82	$ 1.72	$ 0.70	$ 0.62
Cumulative effect adjustment		0.05			
Basic net income per share	$ 0.41	$ 1.87	$ 1.72	$ 0.70	$ 0.62
Diluted net income per share before cumulative effect adjustment	$ 0.40	$ 1.75	$ 1.65	$ 0.69	$ 0.61
Cumulative effect adjustment		0.05			
Diluted net income per share	$ 0.40	$ 1.80	$ 1.65	$ 0.69	$ 0.61

Balance Sheet Data (at end of period):					
Total assets	$141,927	$135,444	$104,900	$72,665	$66,866
Net property and equipment	93,377	96,005	70,597	44,467	55,607
Long-term debt					120
Stockholders equity	107,266	101,740	80,298	58,908	51,308
Working capital	35,954	28,122	25,678	21,408	5,467

29

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This Item 7 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, continued volatility of oil and natural gas prices, estimates of future production and net cash flows attributable to proved reserves, future expenditures, and other such matters. The words anticipates, believes, expects, intends or estimates and similar expressions identify forward-looking statements. Pri does not undertake to update, revise or correct any of the forward-looking information. Readers are cautioned that such forward-looking statements should be read in connection with Prima s disclosures under the heading: Cautionary Statement for the Purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995.

The following discussion is intended to assist in understanding our financial position and results of operations for the three-year period ended December 31, 2002. The Consolidated Financial Statements and notes thereto should be referred to in conjunction with this discussion.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operation are based upon the information reported in our consolidated financial statements. The preparation of these financial statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our decisions on historical experience and various other sources that are believed to be reasonable under the circumstances. Actual results may differ from the estimates we calculated due to changing business conditions or unexpected circumstances. Policies we believe are critical to understanding our business operations and results of operations are detailed below. For additional information on our significant accounting policies you should see Notes to Consolidated Financial Statements, particularly Notes 1 and 11, in our accompanying consolidated financial statements.

Revenue Recognition We engage in the exploration, development, acquisition and production of natural gas and crude oil. Our revenue recognition policy is significant because our revenue is a key component of our results of operations and our forward-looking statements contained in Liquidity and Capital Resources. We derive our revenue primarily from the sale of produced natural gas and crude oil. Revenue is recorded in the month our production is delivered to the purchaser, but payment is generally received between 20 and 90 days after the date of production. At the end of each period we make estimates of the amount of production delivered to the purchaser and the price we received. We use our knowledge of our properties, their historical performance, NYMEX and local spot market prices and other factors as the basis for these estimates. Variances between our estimates and the actual amounts received, which have historically been minimal, are recorded in the month such estimates are revised or when payment is received.

Fair Value of Derivative Instruments Beginning in 2001, the estimated fair values of our derivative instruments are recorded on our consolidated balance sheet. Generally, our derivative instruments are entered into to mitigate risks related to the prices we will receive for our future natural gas and oil production. Although our derivatives are reported on the balance sheet at fair value, to the extent that instruments qualify for hedge accounting treatment, changes in fair value are not included in our consolidated results of operations. Instead, they are recorded net of taxes directly to stockholders equity until the hedged oil or natural gas quantities are produced, at which time any gain or loss realized is recognized as an adjustment to revenues. To the extent changes in the fair values of derivatives relate to instruments not qualifying for hedge accounting treatment, such changes are recorded in income in the period they occur. In determining the amounts to be recorded, we are required to estimate the fair values of derivatives. Our estimates are based upon various factors that include contract volumes and prices, contract settlement dates, quoted closing prices on the NYMEX or over-the-counter and, where applicable, volatility and the time value of options. The calculation of the fair value of collars and floors may require the use of the Black-Scholes option-pricing model, although market quotations will be used to establish fair value when available. For fixed price contracts, the futures prices estimated as of the valuation date are compared to the prices fixed by the derivatives agreements, and the resulting estimated future cash inflows or outflows over the lives of the hedges are discounted to calculate the fair value of the derivative contracts. These pricing and discounting variables are sensitive to market volatility as well as changes in future price expectations, regional price differences and interest rates. We periodically validate our valuations using independent third party quotations.

Reserve Estimates The estimates of our oil and gas reserves are, by necessity, projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable gas and oil reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as expected future production rates, oil and gas prices, operating costs, severance taxes and development costs, all of which may in fact vary considerably from actual results. Future development costs projected for proved undeveloped locations may ultimately increase to an extent that these reserves might not be economically recoverable. For these reasons, estimates of the economically recoverable quantities of oil and gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected there from may vary substantially due to new data or changed assumptions. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of Prima s oil and gas properties and/or the rate of depletion of the oil and gas properties. Actual production, revenues and expenditures with respect Prima s reserves will likely vary from estimates, and such variances may be material.

Full Cost Method We use the full cost method of accounting for our oil and gas activities. Under this method, all costs incurred in the acquisition, development and exploration of oil and gas properties are capitalized into cost centers that are established on a country-by-country basis (we have a single cost center for the United States). Such amounts include the costs of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. Capitalized costs also include salaries, employee benefits, costs of consulting services and other expenses that are directly related to acquisition, development and exploration activities. Costs associated with production and general corporate activities are expensed in the period incurred.

Depletion The capitalized costs of our oil and gas properties, plus estimated future development and abandonment costs related to our proved reserves, are amortized on a unit-of-production method based on our estimate of total proved reserves. The quantities of estimated proved oil and gas reserves are a significant component of amortization, and revisions in such estimates may alter the rate of future expense. Generally, if estimated reserve volumes increase or decrease, then the amortization rate per unit of production will change inversely. However, when estimated future costs change, the amortization rate moves in the same direction. The per-unit rate is not affected by production volumes.

Full Cost Ceiling Limitation Under the full cost method, we are subject to quarterly calculations of a limitation, or ceiling, on the amount that can be capitalized on our balance sheet for oil and gas properties. If the net capitalized costs of our oil and gas properties exceed the cost center ceiling, we are subject to a ceiling test writedown to the extent of such excess. A ceiling test writedown is a non-cash charge to earnings. If required, it would reduce earnings and impact stockholders equity in the period of occurrence and result in lower amortization expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and requires subjective judgments. Given the volatility of oil and gas prices, it is likely that our estimate of discounted future net cash flows from proved reserves will change in the future. If oil and gas prices decline, even if only for a short period of time, or if we have downward revisions to our estimated proved reserves, it is possible that writedowns of our oil and gas properties could occur. While the quantities of proved reserves require substantial judgment, the associated prices of oil and gas reserves that are included in the discounted present value of the reserves do not require judgment. The future net revenues associated with our estimated proved reserves are not based on our assessment of future prices. The ceiling calculation dictates that prices and costs in effect as of the last day of the quarter are assumed to remain constant in the future. However, we may not be subject to a writedown if prices increase shortly after the end of a quarter in which a writedown might otherwise be required.

Unevaluated Costs Unevaluated costs are excluded from our amortization base until we have evaluated the properties associated with these costs. The costs associated with unevaluated leasehold acreage and wells that have not yet been determined to be productive or non-productive are not initially included in our amortization base. Leasehold and associated costs are either transferred to our amortization base with the costs of drilling related wells or are assessed quarterly for possible impairment or reduction in value. Leasehold costs are transferred to our amortization base if estimated fair value is below cost. The decision to withhold costs from amortization and the timing of transferring such costs into the amortization base involves a significant amount of management judgment and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics and results of drilling on adjacent acreage.

Other Property and Equipment Oilfield service equipment and other property and equipment are carried at cost. Renewals and betterments are capitalized, while repairs and maintenance are expensed. Capitalized costs are depreciated using the straight-line method over the estimated useful lives of the assets. The carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset, including disposal value if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. Changes in such estimates could result in a reduction in the carrying value of our property and equipment.

Income Taxes We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared. We, therefore, estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating loss carryforwards. Any differences between estimates we initially used and subsequently determined to be appropriate are recorded in the period in which our estimate is revised.

Liquidity and Capital Resources

Our principal sources of liquidity have been 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.

Net cash provided by operating activities totaled $21,524,000 in the year ended December 31, 2002, compared to $43,008,000 for the year ended December 31, 2001 and $36,376,000 for the year ended December 31, 2000. Our net working capital increased from $28,122,000 at the end of 2001 to $35,954,000 on December 31, 2002. Our cash equivalents and short-term investments also increased in 2002, from $25,755,000 at the beginning of the year to $38,007,000 at the end of 2002, and Prima was free of long-term debt at both dates. We also had no capital lease agreements or guarantees. Our operating lease agreements are disclosed in Note 7 of the Notes to Consolidated Financial Statements.

Prima s revenues and cash flows are substantially derived from oil and gas sales, which are dependent on oil and gas sales prices and production volumes. Oil and gas sales prices have been volatile and our average price realizations in 2002 were 35% lower, on an Mcfe basis, than in 2001. Combined with an 11% decline in net production volumes, these lower prices led to a 42% decline in Prima s oil and gas sales revenue from 2001 to 2002, including hedging effects, from $44,548,000 to $25,785,000. The decline in our oil and gas sales revenue was the primary factor accounting for lower cash flow in 2002. Prima s future revenues will continue to be significantly affected by volatility in oil and gas prices. As further discussed below, oil and gas prices to-date in 2003 and as reflected in futures markets for the balance of the year, are higher than in 2002, and we are projecting an increase in Prima s net production volumes. As such, oil and gas sales, and cash provided by operating activities, are expected to increase in the current year.

We realized $14,577,000 of proceeds from the sale of oil and gas properties in 2002. Approximately $13,514,000 of this amount was realized through the sale on March 5, 2002 of the Stones Throw CBM project in the northern Powder River Basin, associated gathering system facilities and approximately 35,000 net undeveloped acres in the Stones Throw area. The Stones Throw property accounted for approximately 6% of our total estimated proved oil and gas reserves and 4.5% of the related estimated present value of future net cash flows before income taxes, as of the end of 2001. The Stones Throw wells accounted for approximately 17% of our oil and gas production and 8% of our sales revenue before hedging effects in the first two months of 2002.

We invested $22,252,000 in additions to oil and gas properties during 2002, compared to $35,248,000 in 2001 and $31,952,000 in 2000. During 2002, $15,157,000 was expended for oil and gas property development, $5,685,000 for exploratory activities, $876,000 for acquisitions of unproved oil and gas properties, and $534,000 for purchases of proved properties. Other uses of funds in 2002 included $768,000 for other fixed assets, predominantly oilfield service equipment and facilities, and $813,000 for treasury stock repurchases net of proceeds from stock option exercises.

Excluding acquisitions, we plan to make capital investments in 2003 aggregating between $25 million and $30 million. Our initial projected allocation for such investments is approximately as follows: 50% for exploitation of CBM properties in the Powder River Basin; 25% for development of properties in the Denver Basin; 15% for higher-risk exploration activities; and 10% for other operations, including oilfield service companies. The planned CBM activities include drilling a total of 75 to 90 gross wells in our Porcupine-Tuit, Kingsbury, Wild Turkey, and Cedar Draw project areas. Activities planned at Porcupine-Tuit will be primarily for drilling proved undeveloped locations near other wells that have been producing gas at favorable rates from relatively shallow, but thick Wyodak coals for several months. Drilling at the other three projects will be targeting non-proved reserves in deeper coals that have not yet been extensively developed in the area. We anticipate that these deeper coals will need to be de-watered for a longer period of time, perhaps a year or more, before significant gas production rates could be established. As a result, these activities may not generate additions to our production or proved reserves in the current year. If our expectations are realized, however, operations on these properties will result in significant increases in both production and proved reserves in future periods. We intend to review our capital budget on an ongoing basis and may adjust it based on drilling results, changes in oil and gas prices, identification of new opportunities, or other factors. In addition, although not budgeted, we continue to seek acquisitions that we believe will enhance our existing businesses. An acquisition could be consummated using our existing working capital, bank borrowings, and/or through issuance of debt or equity securities.

In January 2001, Prima s Board of Directors approved a repurchase program of up to 5% of our common stock then outstanding, or approximately 640,000 shares. As of December 31, 2002, approximately 403,000 shares remained subject to repurchase under this authorization.

We expect to fund our 2003 oil and gas property exploration, development, and exploitation operations, ordinary equipment additions for our service companies, and any repurchases of common stock with cash provided by operating activities. Working capital on hand at the beginning of the year may also be utilized. Our expectations as to cash provided by operating activities are predicated on projections of oil and gas production volumes, and oil and gas prices, among other factors.

Without any contribution from new exploration or acquisitions, we are projecting that our current year oil and gas production will approximate 12,500,000 Mcfe to 13,000,000 Mcfe, representing year-over-year growth of 18% to 23%. The initial 58 wells that were hooked up at Prima s Porcupine-Tuit project area during the second half of 2002 have performed well, and this CBM project is the principal source of the expected year-over-year production growth. Gross production at Porcupine-Tuit has ramped up to approximately 18,000 Mcf per day at the end of February 2003, and we expect gross production to increase to approximately 21,000 Mcf per day at some point during the second quarter of the

Table of Contents

year, when the third-party contracted to gather our gas in this area is planning to install additional compression. We have been delayed in obtaining permits to access certain drilling locations within our Porcupine-Tuit project area, due to regulatory review and a third-party s appeal of the Forest Service s decision in favor of approving our requested permits. We anticipate a favorable resolution of this appeal and are currently planning to drill approximately 26 wells beginning in the third quarter of 2003. However, this scheduled drilling is dependent upon receiving permit approvals from both the Forest Service and the Bureau of Land Management, and further delays could be encountered. If such delays occur, our estimates of 2003 production could be unfavorably impacted. Prima plans to hook-up four wells drilled at Porcupine-Tuit in 2002 that are currently shut-in later in the year. If drilling permits are secured for new drilling, hook-up of these four wells and new wells drilled in 2003 will be coordinated to maximize efficiencies. Our net working and revenue interests in the existing and planned wells at Porcupine-Tuit average approximately 93% and 78%, respectively.

Natural gas is currently expected to account for more than 85% of Prima s total oil and gas production in 2003. Gas prices have strengthened during the past several months, in response to a number of factors, including (among others):

- cold weather during the winter of 2002-2003 that has reduced storage inventories;
- declining North American natural gas production; and
- a modest response to-date in drilling activity levels in response to higher prices.

As of March 18, 2003, average prices for the 2003 NYMEX gas contracts that have expired (January through March) plus the average of the quoted prices for the remainder of 2003 NYMEX gas contracts combine to average $5.59 per MMBtu of natural gas. These compare to the average closing prices for NYMEX gas contracts during 2002 of $3.34 per MMBtu of natural gas. Our realized gas prices are generally lower than NYMEX, due primarily to location and transportation costs, as discussed below, but these NYMEX comparisons are a reflection of recent price movements in gas markets. There is no assurance, however, that prices reflected in futures markets will actually be realized, except to the extent that fixed price contracts are entered into.

As of the close of business on March 18, 2003, we had forward-sold 200,000 MMBtu of natural gas per month for the months of May 2003 through October 2003, at an average NYMEX price of $5.81 per MMBtu. These contracts do not qualify as effective hedges because we have not locked in the basis differential between the NYMEX-contract Henry Hub delivery point and a Rocky Mountain delivery point near our wells. For the period covered by these NYMEX contracts, this basis differential was quoted at approximately $1.20 per MMBtu discount for The Colorado Interstate Gas (CIG) Index, as of March 18, 2003. An additional 200,000 MMBtu of natural gas have been forward-sold for April 2003, at an average CIG price of $4.20 per MMBtu, which represents an effective hedge. With respect to crude oil, as of March 18, 2003 we had entered into forward-sale NYMEX contracts covering 5,000 barrels per month for the contract months of July 2003 through December 2003, at an average price of $30.75 per barrel. Combined, these positions total approximately 1,580,000 Mcfe of volumes, representing less than 20% of Prima s expected oil and gas production during the last nine months of 2003.

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 natural 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 approximately 80% of our total oil and gas production mix. Gas prices declined significantly after reaching record high levels early in 2001, until early 2003 when prices again approached record levels. These price movements have significantly impacted our operating results, as more fully described below. 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 from short-lived extreme levels of high or low prices.

Table of Contents

In addition to factors affecting global or national markets for oil and natural gas, our business is subject to regional influences on natural 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, CIG gas prices have averaged approximately $0.57 per MMBtu less than the average for gas at Henry Hub, but the amount of this discount has ranged on an annual basis between $0.26 (1999) and $1.37 (2002), and monthly variances in index prices have ranged between an $0.11 premium (January 1993) and a $2.44 discount (October 2002). Basis differentials widened considerably beginning in May 2002, resulting in depressed regional prices for Rocky Mountain gas in 2002 despite relatively strong gas prices in other areas of the country.

Although Rocky Mountain gas prices improved during this past winter, basis differentials have remained wide, as prices in other regions have increased as much or more. Due in part to pipeline capacity expansion projects that will improve access to higher-priced gas markets, commodity futures markets as of March 18, 2003 reflected expectations of moderately improving basis differentials, to $1.32 per MMBtu from May through October 2003, and $0.77 per MMBtu for the winter of 2003-2004. The largest of these planned expansions, and the one scheduled to come on line soonest, is the Kern River Pipeline, which is expected to commence operations in May 2003 with an additional 900,000 Mcf per day of capacity that will move gas from southwest Wyoming to Nevada and California markets. Future basis differentials, which we expect to have an important impact on our operating results, may vary substantially from the current indications on futures markets due to a number of factors, including but not limited to, the timing, size and location of pipeline expansions and the timing, size and location of changes in regional gas deliverability.

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

	2002	2001	2000
Production:			
Natural gas (Mcf)	8,343,000	9,277,000	8,683,000
Oil (barrels)	373,000	431,000	440,000
Total natural gas equivalents (Mcfe)	10,580,000	11,863,000	11,325,000
Revenue:			
Natural gas sales	$16,413,000	$33,392,000	$31,542,000
Oil sales	$ 9,372,000	$11,156,000	$12,895,000
Total oil and gas sales	$25,785,000	$44,548,000	$44,437,000
Avg. sales price (including hedging effects):			
Natural gas (per Mcf)	$ 1.97	$ 3.60	$ 3.63
Oil (per barrel)	$ 25.14	$ 25.88	$ 29.29
Total natural gas equivalents (per Mcfe)	$ 2.44	$ 3.76	$ 3.92
Expenses (per Mcfe):			
Depletion of oil & gas properties	$ 0.92	$ 0.77	$ 0.54
Lease operating expense	$ 0.29	$ 0.28	$ 0.23
Ad valorem and production taxes	$ 0.20	$ 0.28	$ 0.30
General and administrative expense	$ 0.31	$ 0.30	$ 0.26

2002 vs. 2001

For the year ended December 31, 2002, we reported net income of $5,230,000, or $0.40 per diluted share, on revenues of $31,790,000. These amounts compare to net income of $23,768,000, or $1.80 per diluted share, on revenues of $60,287,000, for the year ended December 31, 2001. Total expenses, other than income taxes, were $25,735,000 in

Table of Contents

2002 compared to $26,480,000 in 2001. Revenues decreased $28,497,000 or 47%, expenses decreased $745,000 or 3%, and net income decreased $18,538,000 or 78% in 2002.

Our revenues for 2002 included $3,376,000 of aggregate losses from oil and gas derivatives (see Derivatives Contracts in Note 4 of Notes to Consolidated Financial Statements). This total included hedging losses of $458,000, which were reflected in our oil and gas sales, plus $2,918,000 of separately reported losses on derivative instruments that did not qualify for hedge accounting. Derivative instruments that did not qualify for hedge accounting were principally NYMEX gas swaps for which we did not elect to enter into corresponding swaps for Rocky Mountain basis differentials. The $2,918,000 of recorded losses on non-qualifying derivatives consisted of $1,546,000 of net amounts received by us on settlements of positions closed in 2002, offset by $4,464,000 of net unrealized losses that primarily represented reversals of unrealized mark-to-market gains recognized in the prior year. These reversals occurred because mark-to-market gains on natural gas futures positions held at December 31, 2001 were reduced as gas prices escalated in 2002 before the contracts were settled.

During 2001, we recognized $9,816,000 of gains from oil and gas derivatives, consisting of hedging gains of $3,381,000, realized ineffective hedging gains of $2,057,000, and unrealized mark-to-market gains of $4,378,000. Total gains realized by us on all derivatives pertaining to production months in 2002, including the portion reported as non-hedge derivatives, totaled $1,088,000. Total gains realized on all derivatives related to production months in 2001, including the portion reported as non-hedge derivatives, totaled $5,438,000.

Oil and gas sales reported by us for 2002 totaled $25,785,000, compared to $44,548,000 for 2001, a decrease of 42%. The lower revenues were due to an 11% year-over-year decrease in production volumes and a 35% decrease in the average price realized per equivalent unit of natural gas and oil production. Excluding hedging effects, our oil and gas sales reported for 2002 were $26,243,000, compared to $41,167,000 for 2001, a decrease of $14,924,000 or 36%. Prima s Stones Throw CBM property, which was sold in March 2002, contributed 298,000 net Mcf during the two months the property was owned in 2002, compared to 1,321,000 Mcf in 2001, largely accounting for the declines in gas volumes and net equivalent units. Gas production from the Porcupine-Tuit CBM property, which was initiated at the end of July 2002, roughly offset oil and gas production declines on other properties. Such declines were attributable to a high level of drilling and well recompletion activity in the first half of 2001, in response to a strong commodity price environment, followed by reduced activity levels in the second half of 2001 and in 2002 in response to a significant decline in Rocky Mountain gas prices.

The following information excludes hedging effects (whereas the table above includes hedging effects). The average sales price received by us for natural gas production in 2002 was $1.98 per Mcf, compared to $3.24 per Mcf in 2001, a decrease of $1.26 per Mcf, or 39%. The average price received per barrel of oil was $26.08 in 2002, compared to $25.68 in 2001, representing an increase of $0.40 per barrel or 2%. On an Mcf equivalent basis, the average price received was $2.48 per Mcfe in 2002 compared to $3.47 per Mcfe in the prior year, representing an overall 29% decline in average prices. The portion of our total oil and gas revenues that was derived from natural gas was 63% in 2002 compared to 73% in 2001.

Our natural gas production totaled 8,343,000 Mcf in 2002 compared to 9,277,000 Mcf in 2001, representing a current year decrease of 934,000 Mcf, or 10%. Our oil production totaled 373,000 barrels and 431,000 barrels in 2002 and 2001, respectively, representing a decrease of 58,000 barrels, or 13%. On an equivalent unit basis, production decreased approximately 11%, to 10,580,000 Mcfe in 2002, from 11,863,000 Mcfe in 2001. Total production was 79% natural gas and 21% oil in 2002, compared to 78% gas and 22% oil in the prior year.

Our depletion expense for oil and gas properties in 2002 was $9,710,000, or $0.92 per Mcfe, compared to $9,190,000, or $0.77 per Mcfe, in 2001, an increase of $520,000 or 6%. The increase in the per-unit depletion rate primarily reflects a decline in estimated proved reserve quantities related to Powder River Basin CBM properties. These adjustments are discussed below. Depreciation of other fixed assets, which include service equipment, office furniture and equipment, and buildings, was $1,291,000 and $1,369,000 for 2002 and 2001, respectively.

Table of Contents

Lease operating expenses (LOE) totaled $3,076,000 for the year ended December 31, 2002 compared to $3,295,000 for the year ended December 31, 2001, a decrease of $219,000 or 7%. The decrease was primarily attributable to the sale of the Stone s Throw CBM wells in March 2002. On a per-unit-of-production basis, LOE increased slightly, from $0.28 in 2001 to $0.29 in 2002. Ad valorem and production taxes were $2,116,000 and $3,344,000 for the same periods, a decrease of $1,228,000 or 37%. Production taxes fluctuate with revenues and changing mill levy rates, and averaged 8.1% of total oil and gas sales excluding hedging effects in both 2002 and 2001. Total lifting costs (LOE plus ad valorem and production taxes) were $0.49 per Mcfe for 2002 compared to $0.56 per Mcfe for 2001.

Oilfield services 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 are eliminated in consolidation. Revenues from third parties totaled $8,326,000 for the year ended December 31, 2002 compared to $8,090,000 for the year ended December 31, 2001, an increase of $236,000, or 3%. Costs of oilfield services provided to third parties were $6,287,000 in 2002 compared to $5,482,000 for 2001, an increase of $805,000 or 15%. Approximately 19% of fees billed by the service companies in 2002 were for Prima-owned property interests, compared to 34% in 2001.

General and administrative expenses (G&A), net of third party reimbursements and amounts capitalized, were $3,255,000 for the year ended December 31, 2002 compared to $3,559,000 for the year ended December 31, 2001. Net G&A costs decreased by $304,000 or 9% due to increased third party reimbursements and increased amounts capitalized. Third party reimbursements of management and operator fees increased from $371,000 in 2001 to $405,000 in 2002, due to having increased third party ownership in properties drilled or refractured in the current year. Capitalized G&A increased from $1,573,000 in 2001 to $1,944,000 in 2002, reflecting increased costs associated with exploration, exploitation and development activities.

Our provision for income taxes was $825,000 for the year ended December 31, 2002 compared to $10,650,000 for the year ended December 31, 2001, a decrease of $9,825,000 or 92%. Our effective tax rate decreased to 13.7% in 2002 from 31.5% in 2001. The effective tax rates in both years were less than statutory rates due to permanent differences in book and tax basis income, consisting primarily of statutory depletion deductions and Section 29 tax credits. The lower effective tax rate in 2002 was primarily attributable to a $27,752,000, or 82%, decrease in pre-tax income without a proportionate change in permanent differences. Permanent differences will be smaller in future years, in the absence of new legislation, as a result of the expiration of Section 29 tax credits at the end of 2002.

Proved oil and gas reserves: From the end of 2001 to the end of 2002, our proved oil and gas reserves declined by 24,482 MMcfe, from 135,586 MMcfe to 111,104 MMcfe. The year-over-year decline primarily reflected 8,259 MMcfe of property sales and exchanges, most of which is accounted for by the Stones Throw property disposition, and net revisions aggregating approximately 16,614 MMcfe. Estimated additions to proved reserves from extensions, discoveries and acquisitions in 2002 totaled approximately 10,971 MMcfe, slightly greater than total production during the year of approximately 10,580 MMcfe. Most of Prima s investments in 2002 were directed toward activities that did not add, nor were expected to add, incremental proved reserves during the year, including:

- development of previously-established proved reserves in the Denver Basin and at the Porcupine-Tuit CBM property;
- pilot projects in the Powder River Basin designed to evaluate and develop deeper coal seams, which will generate proved reserves additions in future periods if our expectations are met;
- exploration on the Coyote Flats prospect in Utah, where the initial test well has not yet been completed and determination of commerciality is still pending; and
- exploratory acreage acquisitions.

Net revisions to proved reserves during the year were primarily attributable to Prima s Powder River Basin CBM properties, and reflected more conservative estimation methodology and incorporation of additional data related to non-producing properties with thinner, shallower coals. In addition to incorporating stricter criteria employed by Prima s independent engineers for determining which undrilled CBM locations qualified as having proved reserves, Prima elected

Table of Contents

to prepare estimates of CBM reserves at the end of 2002 utilizing more conservative assumptions than previously used. Among the changes were the following:

- we increased estimated future development and operating costs, to reflect rising costs for certain services and arrangements with surface owners;
- we increased projected costs for water disposal due to anticipated regulatory actions;
- we incorporated expectations of longer lead times for property development, due primarily to anticipated regulatory constraints;
- we modified the projected production profile, to reflect an assumption of longer de-watering times; and,
- we excluded all undrilled locations for which economic runs indicated expected returns above 10%, but less than 20%, to more closely approximate our internal hurdle rate.

As a result, our estimated reserves at the end of 2002 excluded properties with thinner, shallower coals that we do not currently anticipate developing, as we concentrate on higher-potential reserve targets. At December 31, 2002, these higher-potential reserve targets were not proved. Generally, these targets are deeper and thicker coals than the Wyodak coals that were extensively developed in the initial phases of the industry s exploitation of CBM potential in the Powder River Basin. These deeper coals are in the early stages of evaluation and development by Prima and other operators in the area.

2001 vs. 2000

For the year ended December 31, 2001, we reported net income of $23,768,000, or $1.80 per diluted share, on revenues of $60,287,000. These amounts compare to net income of $21,895,000, or $1.65 per diluted share, on revenues of $52,179,000 in the year ended December 31, 2000. Expenses, other than income taxes, were $26,480,000 for 2001 compared to $20,749,000 for 2000. Revenues increased $8,108,000 or 16%, expenses increased $5,731,000 or 28% and net income increased $1,873,000 or 9% in 2001.

Our revenues for 2001 included $9,816,000 of gains from oil and gas derivatives. This total included hedging gains of $3,381,000, which were reflected in oil and gas sales, plus $6,435,000 of separately reported gains on derivative instruments not qualifying for hedge accounting, of which $2,057,000 was realized and $4,378,000 was unrealized as of December 31, 2001. Total gains realized on all derivatives related to production months in 2001, including the portion reported as non-hedge derivatives, totaled $5,438,000. During the prior year, we realized $42,000 of hedging gains, all of which was recognized as a component of oil and gas sales.

Oil and gas sales reported for 2001 totaled $44,548,000, compared to $44,437,000 for 2000, an increase of less than 1%. The flat sales results were creditable to a 5% year-over-year growth in production volumes offset by approximately a like-sized decline in the average price realized per equivalent unit of production. Excluding gains from derivative instruments, oil and gas sales reported for 2001 were $41,167,000, compared to $44,395,000 for 2000, a decrease of $3,228,000 or 7%.

The following information is provided excluding effects of derivatives. The average sales price received for our natural gas production was $3.24 per Mcf in 2001, compared to $3.63 per Mcf in 2000, a decrease of $0.39 per Mcf, or 11%. The average price we received per barrel of oil was $25.68 in 2001, compared to $29.20 in 2000, representing a decrease of $3.52 per barrel or 12%. On an Mcf equivalent basis, the average price received was $3.47 per Mcfe in 2001 compared to $3.92 per Mcfe in the prior year, representing an overall 11% decline in average prices. The portion of total oil and gas revenues that we derived from natural gas was 73% in 2001, compared to 71% in 2000.

Our natural gas production totaled 9,277,000 Mcf in 2001 compared to 8,683,000 Mcf in 2000, representing an increase of 594,000 Mcf, or 7%. Our oil production totaled 431,000 barrels and 440,000 barrels in 2001 and 2000, respectively, representing a decrease of 9,000 barrels, or 2%. On an equivalent unit basis, production increased approximately 5%, to 11,863,000 Mcfe in 2001, from 11,325,000 Mcfe in 2000. Total production was 78% natural gas and 22% oil in 2001, compared to 77% gas and 23% oil in the prior year. Net production from our CBM operations, which totaled 1,453,000

Table of Contents

Mcf in 2001 compared to 7,000 Mcf in 2000, more than offset net decreases from other producing properties that were attributable to natural declines and limited new activity in the second half of 2001.

Our depletion expense for oil and gas properties was $9,190,000, or $0.77 per Mcfe, in 2001, compared to $6,150,000, or $0.54 per Mcfe, in 2000. The increase in the depletion rate reflected a number of factors, including:

- significant declines in oil and gas prices, which, under the methodology prescribed, affects estimates of oil and gas reserves that can be economically recovered through future production;
- increases in oilfield service costs, which impacted actual costs incurred and the assumptions used to estimate future development costs; and
- use of more conservative assumptions for estimating undeveloped CBM reserves.

The depletion rate per Mcfe was increased mid-year 2001 to reflect these factors, and averaged $0.90 during the second half of the year. Depreciation of other fixed assets was $1,369,000 and $1,054,000 for 2001 and 2000, respectively. The increase of $315,000, or 30%, was due primarily to acquisitions of oilfield service equipment in 2000 and 2001.

Our LOE totaled $3,295,000 for the year ended December 31, 2001 compared to $2,623,000 for the year ended December 31, 2000, an increase of $672,000 or 26%. The increase was primarily attributable to new production from CBM wells. Ad valorem and production taxes were $3,344,000 and $3,421,000 for the same periods, a decrease of $77,000 or 2%. Production taxes fluctuate with revenues and changing mill levy rates, and averaged 8.1% of total oil and gas sales excluding hedging effects in 2001 and 7.7% in 2000. Total lifting costs (LOE plus ad valorem and production taxes) were $0.56 per Mcfe for 2001 compared to $0.53 per Mcfe for 2000.

Oilfield service revenues from third parties totaled $8,090,000 for the year ended December 31, 2001, compared to $6,278,000 for the year ended December 31, 2000, an increase of $1,812,000, or 29%. Costs of oilfield services provided to third parties were $5,482,000 in 2001, compared to $4,585,000 for 2000, an increase of $897,000 or 20%. Higher revenues and costs both reflected increases in the amount of equipment placed in service. Improved revenues were also partially attributable to rate increases resulting from increased demand for oilfield services. Approximately 34% of fees billed by the service companies in 2001 were for Prima-owned property interests, compared to 37% in 2000.

G&A, net of third party reimbursements and amounts capitalized, totaled $3,559,000 for the year ended December 31, 2001 compared to $2,916,000 for the year ended December 31, 2000. Net G&A costs increased by $643,000 or 22% due to expansion of our activities and operations, partially offset by increased amounts capitalized. Third party reimbursements of management and operator fees decreased from $426,000 in 2000 to $371,000 in 2001 as the result of acquisitions of additional ownership interests in certain managed properties. Capitalized G&A increased from $1,200,000 in 2000 to $1,573,000 in 2001, reflecting additional costs incurred to manage exploration and development activities.

Our provision for income taxes was $10,650,000 for the year ended December 31, 2001 compared to $9,535,000 for the year ended December 31, 2000, an increase of $1,115,000 or 12%. Prima s effective tax rate increased to 31.5% in 2001 from 30.3% in 2000. The higher effective tax rate in 2001 was primarily attributable to a $2,377,000, or 8%, increase in pre-tax income without a proportionate increase in permanent differences.

Proved oil and gas reserves: From the end of 2000 to the end of 2001, our proved oil and gas reserves declined by 40,960 MMcfe, from 176,546 MMcfe to 135,586 MMcfe. The 23% decline was attributable to a 48,161 MMcfe reduction of previous estimates of proved reserves, largely attributable to using average gas and oil prices that were 74% and 26% lower, respectively, than at the end of 2000. Estimated reserve quantities were particularly affected for our CBM properties in the Powder River Basin, for which average gas prices dropped by 81%, from $7.14 per Mcf at the end of 2000 to $1.38 per Mcf at the end of 2001. Overall, average prices used to calculate proved reserves were $1.94 per Mcf of natural gas and $19.71 per barrel of oil at December 31, 2001, compared to $7.57 and $26.48, respectively, at the end of 2000. Revisions also reflected changes in estimated future costs and more conservative assumptions used to estimate undeveloped CBM reserves, as noted above.

New Accounting Pronouncements

In July 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations . This statement requires companies to recognize the fair value of an asset retirement liability in the financial statements by capitalizing that cost as part of the cost of the related long-lived asset. The asset retirement liability should then be allocated to expense by using a systematic and rational method. The statement is effective January 1, 2003. The Company has not determined the impact of adoption of this statement.

In April 2002 the FASB issued SFAS No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections. This Statement rescinds SFAS No. 4, Reporting Gains and Losses from Extinguishment of Debt , and an amendment of that Statement, SFAS No. 64, Extinguishments of Debt Made to Satisfy Sinking-Fund Requirements. This Statement also rescinds SFAS No. 44, Accounting for Intangible Assets of Motor Carriers. This Statement amends SFAS No. 13, Accounting for Leases, to eliminate an inconsistency between the required accounting for sale-leaseback transactions and the required accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. This Statement also amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. The provisions of this Statement shall be applied in fiscal years beginning after May 15, 2002. We currently do not believe that adoption of this Statement will have an impact on the Company.

In July 2002, the FASB issued SFAS No. 146, Accounting for Costs Associated With Exit or Disposal Activities, which provides guidance for financial accounting and reporting of costs associated with exit or disposal activities and nullifies EITF Issue No. 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring). This statement requires the recognition of a liability for a cost associated with an exit or disposal activity when the liability is incurred, as opposed to when the entity commits to an exit plan under EITF No. 94-3. The statement is effective for the Company in 2003. The adoption of SFAS No. 146 is not expected to have a material effect on the Company s financial position or results of operations.

In December 2002, the FASB issued SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure an amendment of FASB Statement No. 123. SFAS No. 148 amends SFAS No. 123, Accounting for Stock-Based Compensation to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. SFAS No. 148 is effective for financial statements for fiscal years ending after December 15, 2002. Prima currently intends to continue to account for stock based compensation using the methods detailed in the stock-based compensation accounting policy and to provide disclosures as prescribed by SFAS 148.

ITEM 7A. 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 derivative contracts to mitigate a portion of this commodity price risk, or in an effort to enhance profitability. 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. Generally, 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 typically limit the benefits we realize from increases in prices or narrowing of basis differentials. When hedging 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. We also retain risks related to the ineffective portion of such derivatives instruments, when applicable.

Table of Contents

We may enter into derivatives positions intended to offset risks associated with downward price movements in benchmark NYMEX oil and gas prices, as well as basis swaps to protect us from increases in the differential between NYMEX and Rocky Mountain gas prices. Our derivatives contracts generally 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. At times, however, we may consider establishing derivative positions that do not represent cash flow hedges. See Note 1 and Note 4 of Notes to Consolidated Financial Statements for additional information with respect to derivatives and related accounting policies.

Personnel who we believe have appropriate skills and experience execute all derivatives transactions. The personnel involved in these activities must follow prescribed trading limits and parameters that are regularly reviewed by our Chief Executive Officer. Our Chief Executive Officer approves all derivatives transactions before being entered into and our Board of Directors regularly reviews outstanding positions and hedging strategy. We use only conventional derivatives instruments and attempt to manage our credit risk by entering into derivatives contracts only with financial institutions that we believe to be reputable and which carry an investment grade rating.

Following are disclosures regarding our 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 positions. It is not possible to accurately predict future movements in natural gas and oil prices.

During 2002, we sold 373,000 barrels of produced oil. A hypothetical decrease of $2.61 per barrel (10% of average prices for the period exclusive of hedging transactions) would have decreased our revenues by $974,000 for the period. We sold 8,343,000 Mcf of produced natural gas during the same period. A hypothetical decrease of $0.20 per Mcf (10% of average prices for the period exclusive of hedging transactions) would have decreased our revenues by $1,669,000 for the period.

We closed on certain derivatives positions between the end of 2002 and March 18, 2003, for net realized losses totaling $162,000. As of the close of business on March 18, 2003, our open oil and gas derivatives instruments reflected net unrealized mark-to-market gains of $992,000, as follows:

Time Period	Market Index	Total Volumes (MMBtu or Bbls)	Average Contract Price	Unrealized Gains
Natural Gas Futures				
April 2003	CIG	200,000	$ 4.200	$ 184,000
May - October 2003	NYMEX	1,200,000	5.813	711,000
Oil Futures				
July - December 2003	NYMEX	30,000	30.750	97,000
Total Unrealized Gains				$ 992,000

The CIG natural gas contracts, but not the NYMEX natural gas contracts, are considered to be effective hedges, since Prima s current production is all located in the Rocky Mountain region. For the period covered by these NYMEX contracts, a recent quote to lock in the basis differential, which would convert the NYMEX natural gas contracts to effective hedges, was approximately a $1.20 per MMBtu discount for Rocky Mountain natural gas. The oil contracts also represent effective hedges. Combined, these positions total approximately 1,580,000 Mcfe of volumes, representing less than 20% of Prima s expected oil and gas production during the last nine months of 2003.

Table of Contents

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our Consolidated Financial Statements are attached at the end of this Annual Report on Form 10-K. An index to these Consolidated Financial Statements is also included in Item 15(a) of this Annual Report on Form 10-K.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Since our inception, there has not been any Form 8-K filed under the Securities Exchange Act of 1934 reporting a change in accountants in which there was a reported disagreement on any matter of accounting principles or practices or financial statement disclosure.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

ITEM 11. EXECUTIVE COMPENSATION

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Pursuant to instruction G(3) to Form 10-K, Items 10, 11, 12, and 13 are omitted because we will file a definitive proxy statement pursuant to Regulation 14A under the Securities Exchange Act of 1934 not later than 120 days after the close of the fiscal year. The information required by such Items will be included in the definitive proxy statement to be filed for our annual meeting of stockholders scheduled for May 12, 2003 and is hereby incorporated by reference.

ITEM 14. CONTROLS AND PROCEDURES

Prima s principal executive officer and principal financial officer have evaluated the effectiveness of our disclosure controls and procedures, as such term is defined in Rule 13a-14(c) and 15d-14(c) of the Securities Exchange Act of 1934, as amended, within 90 days of the filing date of this Annual Report on Form 10-K. Based upon their evaluation, our principal executive officer and principal financial officer concluded that Prima s disclosure controls and procedures are effective. There were no significant changes in our internal controls or in other factors that could significantly affect these controls, since the date the controls were evaluated.

Table of Contents

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) (1) Financial Statements

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

(a) (2) Financial Statement Schedules

Financial statement schedules have been omitted because they are not applicable or the information required therein is included elsewhere in the financial statements or notes thereto.

(b) Reports on Form 8-K

During the quarter ended December 31, 2002, Prima filed the following current reports on Form 8-K:

Report dated November 12, 2002, reporting earnings for the quarter and nine months ended September 30, 2002, and providing an update on operating activities and commodity hedging.

Report dated November 14, 2002 submitting certifications by the Chief Executive Officer and Chief Financial Officer of Prima Energy Corporation pursuant to 18 U.S.C. §1350 as adopted by §906 of the Sarbanes-Oxley Act of 2002.

Report dated November 29, 2002 providing an update on its exploratory well in the Coyote Flats prospect, reporting on a joint venture agreement reached with a private company to develop coal bed methane reserves in the Powder River Basin, and announcing the resignation of its Vice President of Corporate Development.

(c) Exhibits

The following exhibits are filed with or are incorporated by reference into this report on Form 10-K.

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.)

Table of Contents

Exhibit No.	Document
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 for the year ended June 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 for the quarter ended June 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 for the quarter ended 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 for the quarter ended June 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 for the year ended June 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 for the year ended 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 for the year ended 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 for the quarter ended 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 for the quarter ended March 31, 2002.)
21	Subsidiaries of the Registrant
23.1	Consent of Independent Auditors
23.2	Consent of Independent Reservoir Engineers and Geologists

Table of Contents

INDEPENDENT AUDITORS REPORT

Prima Energy Corporation:

We have audited the accompanying consolidated balance sheets of Prima Energy Corporation (Company) and subsidiaries as of December 31, 2002 and 2001, and the related consolidated statements of income, comprehensive income, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company and its subsidiaries at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, in 2001 the Company adopted Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities.

DELOITTE & TOUCHE LLP

March 14, 2003
Denver, Colorado

Table of Contents

PRIMA ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2002 and 2001

ASSETS

	2002	2001
CURRENT ASSETS		
Cash and cash equivalents	$ 36,263,000	$ 23,337,000
Available for sale securities, at market	1,744,000	2,418,000
Receivables (net of allowance for doubtful accounts: $304,000 and $295,000)	7,492,000	5,806,000
Derivatives, at fair value		4,472,000
Inventory	940,000	1,415,000
Other	818,000	710,000
Total current assets	47,257,000	38,158,000
OIL AND GAS PROPERTIES, at cost, accounted for using the full cost method:		
Proved	130,948,000	130,710,000
Unproved	20,570,000	13,132,000
Less accumulated depreciation, depletion and amortization	(62,980,000)	(53,270,000)
Oil and gas properties net	88,538,000	90,572,000
PROPERTY AND EQUIPMENT, at cost		
Oilfield service equipment	9,457,000	9,159,000
Furniture and equipment	712,000	694,000
Field office, shop and land	478,000	473,000
	10,647,000	10,326,000
Less accumulated depreciation	(5,808,000)	(4,893,000)
Property and equipment net	4,839,000	5,433,000
OTHER ASSETS	1,293,000	1,281,000
	$ 141,927,000	$ 135,444,000

See accompanying notes to consolidated financial statements.

Table of Contents

PRIMA ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS (cont d.)
DECEMBER 31, 2002 and 2001

LIABILITIES AND STOCKHOLDERS EQUITY

	2002	2001
CURRENT LIABILITIES		
Accounts payable	$ 3,129,000	$ 1,668,000
Amounts payable to oil and gas property owners	3,192,000	1,910,000
Ad valorem and production taxes payable	3,864,000	3,272,000
Accrued and other liabilities	893,000	1,408,000
Derivatives, at fair values	225,000	
Deferred tax liability		1,778,000
Total current liabilities	11,303,000	10,036,000
AD VALOREM TAXES, non-current	2,077,000	3,302,000
DEFERRED INCOME TAX LIABILITY	21,281,000	20,366,000
Total liabilities	34,661,000	33,704,000
STOCKHOLDERS EQUITY		
Preferred stock, $0.001 par value, 2,000,000 shares authorized; no shares issued		
Common stock, $0.015 par value, 35,000,000 shares authorized; 13,064,048 and 12,889,923 shares issued	196,000	193,000
Additional paid-in capital	5,250,000	3,147,000
Retained earnings	107,470,000	102,240,000
Accumulated other comprehensive income (loss)	(115,000)	26,000
Treasury stock, 236,538 and 155,351 shares, at cost	(5,535,000)	(3,866,000)
Stockholders equity net	107,266,000	101,740,000
	$ 141,927,000	$ 135,444,000

See accompanying notes to consolidated financial statements.

Table of Contents

PRIMA ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF INCOME
FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 and 2000

	2002	2001	2000
REVENUES			
Oil and gas sales	$25,785,000	$44,548,000	$44,437,000
Gains (losses) on derivative instruments, net	(2,918,000)	6,435,000	
Oilfield services	8,326,000	8,090,000	6,278,000
Interest, dividend and other income	597,000	1,214,000	1,464,000
	31,790,000	60,287,000	52,179,000
EXPENSES			
Depreciation, depletion and amortization:			
Depletion of oil and gas properties	9,710,000	9,190,000	6,150,000
Depreciation of property and equipment	1,291,000	1,369,000	1,054,000
Lease operating expense	3,076,000	3,295,000	2,623,000
Ad valorem and production taxes	2,116,000	3,344,000	3,421,000
Oilfield services	6,287,000	5,482,000	4,585,000
General and administrative	3,255,000	3,559,000	2,916,000
Impairment of natural gas swap		241,000	
	25,735,000	26,480,000	20,749,000
Income before income taxes and cumulative effect of change in accounting principle	6,055,000	33,807,000	31,430,000
Provision for income taxes	825,000	10,650,000	9,535,000
Net income before cumulative effect of change in accounting principle	5,230,000	23,157,000	21,895,000
Cumulative effect of change in accounting principle (net of income taxes of $265,000)		611,000	
NET INCOME	$ 5,230,000	$23,768,000	$21,895,000
Basic net income per share before cumulative effect of change in accounting principle	$ 0.41	$ 1.82	$ 1.72
Cumulative effect of change in accounting principle		0.05	
BASIC NET INCOME PER SHARE	$ 0.41	$ 1.87	$ 1.72
Diluted net income per share before cumulative effect of change in accounting principle	$ 0.40	$ 1.75	$ 1.65
Cumulative effect of change in accounting principle		0.05	
DILUTED NET INCOME PER SHARE	$ 0.40	$ 1.80	$ 1.65

See accompanying notes to consolidated financial statements.

Table of Contents

PRIMA ENERGY CORPORATION

**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 and 2000**

	2002	2001	2000
Net income	$5,230,000	$23,768,000	$21,895,000
Other comprehensive income (loss):			
Change in fair value of hedges	(690,000)	3,475,000	
Reclassification adjustment for realized losses (gains) on hedges included in net income	458,000	(3,381,000)	
Deferred income tax benefit (expense) related to change in fair value of hedges	86,000	(35,000)	
Change in fair value of available-for-sale securities	(16,000)	147,000	170,000
Reclassification adjustment for realized losses included in net income	25,000	1,000	18,000
Deferred income tax expense related to change in fair value of available-for-sale securities	(4,000)	(55,000)	(70,000)
	(141,000)	152,000	118,000
COMPREHENSIVE INCOME	$5,089,000	$23,920,000	$22,013,000

See accompanying notes to consolidated financial statements.

Table of Contents

PRIMA ENERGY CORPORATION

**CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 and 2000**

	Common Stock, Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total
BALANCES, January 1, 2000	$198,000	$ 5,628,000	$ 56,577,000	$(244,000)	$(3,251,000)	$ 58,908,000
Net income			21,895,000			21,895,000
Exercise of stock options	1,000	591,000				592,000
Tax benefit from exercise of non- qualified stock options		720,000				720,000
Other comprehensive income				118,000		118,000
Treasury stock purchased					(1,935,000)	(1,935,000)
Treasury stock canceled	(7,000)	(5,179,000)			5,186,000	
BALANCES, December 31, 2000	192,000	1,760,000	78,472,000	(126,000)		80,298,000
Net income			23,768,000			23,768,000
Exercise of stock options	1,000	525,000				526,000
Tax benefit from exercise of non- qualified stock options		732,000				732,000
Other comprehensive income				152,000		152,000
Treasury stock purchased					(3,866,000)	(3,866,000)
Other		130,000				130,000
BALANCES, December 31, 2001	193,000	3,147,000	102,240,000	26,000	(3,866,000)	101,740,000
Net income			5,230,000			5,230,000
Exercise of stock options	3,000	853,000				856,000
Tax benefit from exercise of non- qualified stock options		1,250,000				1,250,000
Other comprehensive income (loss)				(141,000)		(141,000)
Treasury stock purchased					(1,669,000)	(1,669,000)
BALANCES, December 31, 2002	$196,000	$ 5,250,000	$107,470,000	$(115,000)	$(5,535,000)	$107,266,000

See accompanying notes to consolidated financial statements.

Table of Contents

PRIMA ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 and 2000

	2002	2001	2000
OPERATING ACTIVITIES			
Net income	$ 5,230,000	$ 23,768,000	$ 21,895,000
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	11,001,000	10,559,000	7,204,000
Deferred income taxes	(977,000)	9,123,000	7,319,000
Unrealized derivative activities	4,464,000	(4,378,000)	
Tax benefits from stock option plans	1,250,000	732,000	720,000
Other	95,000	(106,000)	25,000
Changes in operating assets and liabilities:			
Receivables	(1,698,000)	3,096,000	(3,618,000)
Inventory	475,000	(6,000)	(572,000)
Other current assets	89,000	241,000	(129,000)
Accounts payable and payables to owners	2,743,000	(2,130,000)	2,124,000
Production taxes payable	(633,000)	1,504,000	2,344,000
Accrued and other liabilities	(515,000)	605,000	(936,000)
Net cash provided by operating activities	21,524,000	43,008,000	36,376,000
INVESTING ACTIVITIES			
Additions to oil and gas properties	(22,252,000)	(35,248,000)	(31,952,000)
Proceeds from sales of oil and gas property	14,577,000	57,000	
Purchases of other properties net of proceeds	(768,000)	(1,746,000)	(1,390,000)
Sales (purchases) of securities net	658,000	41,000	(192,000)
Net cash used in investing activities	(7,785,000)	(36,896,000)	(33,534,000)
FINANCING ACTIVITIES			
Treasury stock purchased	(1,669,000)	(3,866,000)	(1,935,000)
Proceeds from exercise of stock options	856,000	526,000	592,000
Other		183,000	
Net cash used in financing activities	(813,000)	(3,157,000)	(1,343,000)
Increase in cash and cash equivalents	12,926,000	2,955,000	1,499,000
Cash and cash equivalents, beginning of year	23,337,000	20,382,000	18,883,000
CASH AND CASH EQUIVALENTS, end of year	$ 36,263,000	$ 23,337,000	$ 20,382,000

See accompanying notes to consolidated financial statements.

Table of Contents

PRIMA ENERGY CORPORATION

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 and 2000**

1. ORGANIZATION AND SIGNIFICANT ACCOUNTING POLICIES

Business and Basis of Presentation

The accompanying consolidated financial statements include the accounts of Prima Energy Corporation and its wholly owned subsidiaries, herein collectively referred to as Prima or the Company. Prima s primary business is the exploration for, and the acquisition, development and production of, crude oil and natural gas. The Company is also engaged in oil and gas property operations and oilfield services, and, at times, has engaged in natural gas gathering, marketing and trading. Prima s activities have been conducted predominantly in the Rocky Mountain region of the United States.

The Company s proportionate share of capital expenditures, production revenue and operating expenses from working interests in oil and gas properties is included in the consolidated financial statements. All significant intercompany transactions have been eliminated. Certain amounts in prior years have been reclassified to conform to the classifications at December 31, 2002.

Use of Estimates

The preparation of the Company s financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates.

Comprehensive Income

Comprehensive income consists of net income, unrealized gains and losses on marketable equity securities held for sale, and the effective component of derivative instruments classified as cash flow hedges, net of income tax effects. Comprehensive income is presented in the Consolidated Statements of Comprehensive Income.

Consolidated Statements of Cash Flows

Cash in excess of daily requirements is generally invested in money market accounts and commercial paper with maturities of three months or less. Such investments are deemed to be cash equivalents for purposes of the consolidated financial statements.

Cash paid for income taxes was $1,187,000, $905,000 and $2,722,000 for the years ended December 31, 2002, 2001 and 2000, respectively. No interest was paid in 2002 or 2001. Cash paid for interest in 2000 was $15,000.

Estimated Fair Value of Financial Instruments and Available for Sale Securities

The carrying amount of cash equivalents approximates fair value because of the short maturity and high credit quality of those investments.

Marketable securities are classified as available for sale, and are carried on the balance sheet at market value. Unrealized gains and losses, net of deferred income taxes, are generally reported as other comprehensive income and as an adjustment to stockholders equity. If a decline in market value below cost is assessed as being other than temporary, such impairment is included in the determination of net income. Available-for-sale securities are readily marketable and available for use in Prima s operations should the need arise. Therefore, the Company has classified such securities as current assets. Realized gains and losses are determined on the specific identification method.

Commencing with its adoption of Statement of Financial Accounting Standards No. 133 on January 1, 2001, Prima has recognized all derivatives on its balance sheet at their estimated fair values. The fair values of these contracts are determined based on various factors, including contract volumes and prices, contract settlement dates, quoted closing prices on the NYMEX or over-the-counter and, where applicable, volatility and the time value of options. The calculation of the fair value of collars and floors requires the use of the Black-Scholes option-pricing model, but market quotations are generally available. Substantially all of the Company s derivatives positions are valued based upon reported settlement prices on the NYMEX or as quoted in relatively liquid over-the-counter markets by a number of market makers.

Inventory

Inventory consists of various tubular goods and surface production facility equipment intended to be used in Prima s oil and gas operations, and is stated at the lower of cost or market value using the first-in, first-out valuation method.

Oil and Gas Properties

Prima utilizes the full cost method of accounting for oil and gas producing activities. Under this method, all costs associated with property acquisition, exploration and development, including costs of unsuccessful exploration, are capitalized within a cost center. Prima s oil and gas properties are all located within the United States, which constitutes a single cost center. No gain or loss is recognized upon the sale or abandonment of undeveloped or producing oil and gas properties unless the sale represents a significant portion of oil and gas properties and the gain significantly alters the relationship between capitalized costs and proved oil and gas reserves of the cost center. Depreciation, depletion and amortization of oil and gas properties is computed on the units-of-production method based on proved reserves. Amortizable costs include estimates of future development costs of proved undeveloped reserves. Prima invests in unevaluated oil and gas properties for the purpose of exploration for proved reserves. The costs of such assets, including exploration costs on properties where a determination of whether proved oil and gas reserves will be established is still pending, are included in unproved oil and gas properties at the lower of cost or estimated fair market value and are not subject to amortization.

Capitalized costs of oil and gas properties may not exceed an amount equal to the present value, discounted at 10%, of the estimated future net cash flows from proved oil and gas reserves plus the cost, or estimated fair market value if lower, of unproved properties. Should capitalized costs exceed this ceiling, an impairment is recognized. The present value of estimated future net cash flows is computed based on revenues derived using oil and natural gas prices and projected future production of proved reserves as of the balance sheet date, less estimated future expenditures to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Prima did not recognize any impairment losses during the three-year period ended December 31, 2002.

The Company has not accrued costs for future site restoration, dismantlement and abandonment costs related to proved oil and gas properties because management has estimated that such costs will be fully offset by the salvage value of equipment sold upon abandonment of these properties. Such estimates have been based upon the Company s historical experience and review of its current properties and restoration obligations. In accordance with Statement of Financial Accounting Standards (SFAS) No. 143, discussed below, Prima will begin to accrue asset retirement costs, without offset for projected equipment salvage values, effective January 1, 2003.

Property and Equipment

Property and equipment is recorded at cost. Renewals and betterments that substantially extend the useful lives of the assets are capitalized. Maintenance and repairs are expensed when incurred. Depreciation is provided using the straight-line method over the estimated useful lives of the assets, ranging from three to 15 years. Long-lived assets, other than oil and gas properties, are evaluated for impairment to determine if current circumstances and market conditions indicate that the carrying amount of an asset may not be recoverable. Prima did not recognize any impairment losses during the three-year period ended December 31, 2002.

Natural Gas Imbalances

Prima utilizes the accrual method of accounting for natural gas revenues whereby revenues are recognized as the Company s entitlement share of gas is produced and sold based on its net revenue interests in the properties. The Company records a receivable (payable) to the extent it receives less (more) than its proportionate share of gas revenues. The imbalance position was not significant at the end of 2002 or 2001.

Oilfield Services and Operator Fees

Fees earned from providing oilfield services and operating wells for third parties are recorded when the services are performed. Oilfield services fees are recognized as income. Operating fees are recorded as a reduction of general and administrative expenses.

Income Taxes

Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income tax assets and liabilities represent the future tax return consequences of those differences, which will either be taxable or deductible when the assets and liabilities are recovered or settled. Deferred income tax benefits are also recognized for tax credits that are available to offset future federal income taxes. Deferred income taxes are determined by applying currently enacted tax rates.

Derivative Instruments and Hedging Activities

Prima periodically enters into derivative contracts to mitigate risks associated with downward price movements in benchmark NYMEX gas and oil prices or, in the case of basis swaps, to protect the Company from increases in the differential between NYMEX and Rocky Mountain gas prices. These derivative contracts generally represent cash flow hedges that are determined to be qualifying or non-qualifying for hedge accounting treatment in accordance with the provisions of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. Derivatives may be entered into in an effort to enhance profitability, as well as mitigate risks.

SFAS 133 prescribes that the fair value of all derivatives should be recognized as either assets or liabilities on the balance sheet. SFAS 133 also establishes requirements for designation and documentation of hedging relationships and ongoing effectiveness assessments. Hedge effectiveness is measured based on the relative changes over time in the fair values of a derivative and the related hedged item. If a cash flow hedge qualifies for hedge accounting under SFAS 133, and is so designated by the Company, changes in the fair value of the derivative are recorded initially in other comprehensive income and then recognized in the income statement when the hedged item affects earnings. If a derivatives position does not qualify for hedge accounting under SFAS 133, or if the Company so elects, changes in the fair value of the derivative are immediately recognized in earnings. Prima generally elects to use hedge accounting when conditions to do so are satisfied.

The Company has determined that pursuant to SFAS 133 requirements, and based on its current sources of oil and gas production, that swaps, collars, puts or floors that are based on NYMEX oil prices or CIG gas prices qualify for hedge accounting. Derivatives based on NYMEX gas prices will not so qualify unless corresponding transactions are entered into to hedge basis differentials between NYMEX and CIG indices. In addition, stand-alone basis differential swaps, sales of call options, and positions that do not mitigate risk do not qualify for hedge accounting.

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, net-of-tax cumulative effect adjustments reducing other comprehensive income by $129,000, and an increase in net income by $611,000. The $611,000 is reflected as the cumulative effect of a change in accounting principle in the December 31, 2001 financial statements.

Table of Contents

Stock-Based Compensation

At December 31, 2002, Prima had stock-based compensation plans in effect, which are more fully described in Note 8. The Company accounts for stock-based compensation using the intrinsic value recognition and measurement principles prescribed in Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees (APB No. 25) 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 also require the input of highly subjective assumptions, including the projected life of the options and expected stock price volatility. 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.

The following assumptions were utilized to estimate the fair values of options granted during the three years ended December 31, 2002, using the Black-Scholes Valuation Model:

	2002	2001	2000
Expected dividend yield	0%	0%	0%
Expected price volatility	41%	43%	76%
Risk free interest rate	2.9%	5.1%	6.1%
Expected life of options (in years)	6	6	9

Based on the above, the estimated weighted average fair values of employee stock options granted during 2002 and 2001 were $11.52 and $16.04, respectively. No employee stock options were granted in 2000. The weighted average fair values of non-employee directors options granted during 2002, 2001 and 2000 were $9.04, $12.49 and $20.47, respectively. Additional awards in future years are anticipated.

For purposes of pro forma disclosures, the estimated 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 the Company had applied the fair value recognition provisions of SFAS No. 123.

	2002	2001	2000
Net Income			
As reported	$5,230,000	$23,768,000	$21,895,000
Pro forma	$4,342,000	$23,359,000	$21,585,000
Basic net income per share			
As reported	$ 0.41	$ 1.87	$ 1.72
Pro forma	$ 0.34	$ 1.83	$ 1.69
Diluted net income per share			
As reported	$ 0.40	$ 1.80	$ 1.65
Pro forma	$ 0.33	$ 1.77	$ 1.62

Table of Contents

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 the options to acquire common stock described in Note 8, computed using the treasury stock method. The treasury stock method assumes that the increase in the number of shares issued is reduced by the number of shares that could have been repurchased by the Company with the proceeds from the exercise of the options (assuming an acquisition cost equal to the average market price of the common shares during the reporting period).

New Accounting Pronouncements

In July 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations . This statement requires companies to recognize the fair value of an asset retirement liability in the financial statements by capitalizing that cost as part of the cost of the related long-lived asset. The asset retirement liability should then be allocated to expense by using a systematic and rational method. The statement is effective January 1, 2003. The Company has not determined the impact of adoption of this statement.

In April 2002 the FASB issued SFAS No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections. This Statement rescinds SFAS No. 4, Reporting Gains and Losses from Extinguishment of Debt , and an amendment of that Statement, SFAS No. 64, Extinguishments of Debt Made to Satisfy Sinking-Fund Requirements. This Statement also rescinds SFAS No. 44, Accounting for Intangible Assets of Motor Carriers. This Statement amends SFAS No. 13, Accounting for Leases, to eliminate an inconsistency between the required accounting for sale-leaseback transactions and the required accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. This Statement also amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. The provisions of this Statement shall be applied in fiscal years beginning after May 15, 2002. The adoption of SFAS No. 145 is not expected to have a material effect on the Company s financial position or results of operations.

In July 2002, the FASB issued SFAS No. 146, Accounting for Costs Associated With Exit or Disposal Activities, which provides guidance for financial accounting and reporting of costs associated with exit or disposal activities and nullifies EITF Issue No. 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring). This statement requires the recognition of a liability for a cost associated with an exit or disposal activity when the liability is incurred, as opposed to when the entity commits to an exit plan under EITF No. 94-3. The statement is effective for the Company in 2003. The adoption of SFAS No. 146 is not expected to have a material effect on the Company s financial position or results of operations.

In December 2002, the FASB issued SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure an amendment of FASB Statement No. 123. SFAS No. 148 amends SFAS No. 123, Accounting for Stock-Based Compensation to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. SFAS No. 148 is effective for financial statements for fiscal years ending after December 15, 2002. The Company currently intends to continue to account for stock-based compensation using the methods detailed in the stock-based compensation accounting policy and to provide disclosures as prescribed by SFAS 148.

Table of Contents

2. AVAILABLE-FOR-SALE SECURITIES

Prima s available-for-sale securities are comprised of marketable equity securities, including closed-end bond funds. During the years ended December 31, 2002 and 2001, the Company sold securities with a market value of $929,000 and $166,000, which resulted in realized gains and losses of $66,000 and $(1,000), respectively. The Company also determined that there was an other-than-temporary decline in the fair market value of an individual security in its portfolio. Consequently, an impairment loss of $91,000 was recognized in 2002. Other net unrealized losses on securities are included in accumulated other comprehensive income, net of deferred income taxes of $(16,000) and $(20,000), respectively, at December 31, 2002 and 2001. The changes in net unrealized losses on securities for the years ended December 31, 2002 and 2001 were as follows:

	2002	2001
Net unrealized (loss), beginning of year	$(53,000)	$(201,000)
Net unrealized (loss), end of year	(44,000)	(53,000)
Net change in unrealized loss	$ 9,000	$ 148,000

The components of fair value as of December 31, 2002 and 2001 were as follows:

	2002	2001
Cost (including reinvested distributions)	$1,788,000	$2,471,000
Gross unrealized gains	46,000	88,000
Gross unrealized losses	(90,000)	(141,000)
Fair value	$1,744,000	$2,418,000

3. EARNINGS PER SHARE AND COMMON STOCK

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
Year Ended December 31, 2002:			
Basic Net Income per Share	$ 5,230,000	12,770,716	$ 0.41
Effect of Stock Options		450,660	
Diluted Net Income per Share	$ 5,230,000	13,221,376	$ 0.40
Year Ended December 31, 2001:			
Basic Net Income per Share	$23,768,000	12,731,181	$ 1.87
Effect of Stock Options		487,970	
Diluted Net Income per Share	$23,768,000	13,219,151	$ 1.80

Year Ended December 31, 2000:			
Basic Net Income per Share	$21,895,000	12,748,917	$ 1.72
Effect of Stock Options		544,006	
Diluted Net Income per Share	$21,895,000	13,292,923	$ 1.65

The Board of Directors of Prima approved two separate three-for-two stock splits of the Company common stock during 2000. All share and per-share amounts included in these financial statements have been restated to show the retroactive effects of the stock splits.

Table of Contents

During 2000, Prima purchased 108,150 shares of its common stock for its treasury for $1,935,000. The Board of Directors authorized the retirement of 431,199 shares of common stock held in the treasury as of December 31, 2000. These shares were returned to an authorized but unissued status. In January 2001, the Board approved a repurchase program of up to 5% of the Company s common stock then outstanding, or approximately 640,000 shares. In 2001, the Company purchased 155,351 treasury shares for $3,866,000. In 2002, the Company purchased 81,187 treasury shares for $1,669,000. The combined total of 236,538 shares repurchased to date represents approximately 1.8% of the shares then outstanding, or 37% of the shares authorized for repurchase under the program. As of December 31, 2002, approximately 403,000 shares remained subject to repurchase under this authorization. Through March 18, 2003, Prima had repurchased an additional 29,700 treasury shares at an average cost of $18.74 per share.

During 2000, the stockholders of Prima approved an increase in the number of authorized shares of common stock from 12,000,000 to 18,000,000 shares. During 2001, the stockholders approved an additional increase to 35,000,000 authorized shares.

4. DERIVATIVES CONTRACTS

Prima periodically enters into derivative contracts to mitigate risks associated with downward price movements in benchmark NYMEX gas and oil prices or, in the case of basis swaps, to protect the Company from increases in the differential between NYMEX and Rocky Mountain gas prices. While such hedges can reduce the adverse effects of oil and gas price declines, they may also limit the benefits of price increases. These derivatives contracts generally represent cash flow hedges that are determined to be qualifying or non-qualifying for hedge accounting treatment in accordance with the provisions of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. Derivatives may be entered into in an effort to enhance profitability, as well as mitigate risks.

The Company has entered into various cash flow hedges related to its oil and gas production. Some of these derivatives qualify for hedge accounting, while others are non-qualifying. Derivative instruments that did not qualify for hedge accounting were principally NYMEX gas swaps for which we did not enter into corresponding swaps for Rocky Mountain basis differentials. The following table summarizes the income statement effects of these transactions in 2002, 2001 and 2000:

	2002	2001	2000
Realized gains (losses) on derivatives qualifying for hedge accounting, included in oil and gas sales	$ (458,000)	$3,381,000	$42,000
Realized gains on non-qualifying hedges	1,546,000	2,057,000	
Unrealized gains (losses) on non-qualifying hedges	(4,464,000)	4,378,000	
Aggregate amounts reported on consolidated statements of income	$(3,376,000)	$9,816,000	$42,000

On December 31, 2002, Prima s open hedge positions, all of which related to the first quarter of 2003, consisted of 200,000 MMBtu of natural gas sold forward at an average NYMEX price of $3.3155 per MMBtu. The unrealized mark-to-market losses for these derivative positions, aggregating $225,000 at that date, were included in current liabilities as of December 31, 2002. Gas prices are volatile and the market value of these derivatives changes as the underlying commodity futures prices change. Actual gains or losses realized will depend on the applicable futures prices in effect at the time such positions are closed. Mark-to-market adjustments could result in significant earnings volatility.

In addition, $139,000 of realized losses on closed derivatives positions that qualified for hedge accounting were included in other comprehensive income in 2002 and will be included as a reduction of oil and gas sales in 2003, as the related production months occur.

Table of Contents

5. INCOME TAXES

The provision for income taxes consists of the following components:

	2002	2001	2000
Current:			
Federal	$1,636,000	$ 2,067,000	$2,114,000
State	166,000	(275,000)	102,000
	1,802,000	1,792,000	2,216,000
Deferred:			
Federal	(429,000)	8,732,000	6,656,000
State	(35,000)	782,000	382,000
	(464,000)	9,514,000	7,038,000
Tax credits	(513,000)	(391,000)	281,000
Provision for income taxes	$ 825,000	$10,915,000	$9,535,000

During 2002, 2001 and 2000, the Company recognized income tax deductions of $3,375,000, $1,979,000 and $1,946,000, respectively, from the exercise of nonqualified stock options. Stockholders equity has been credited in the amount of $1,250,000, $732,000 and $720,000 for the income tax benefit of these deductions. The provision for income taxes in 2001 included $265,000 of current expense that was netted in the cumulative effect of change in accounting method. During 2001, Prima recognized taxable income of $207,000 from short-swing profits. Stockholders equity has been reduced in the amount of $77,000 for the current income tax expense associated with this income.

The significant components of deferred tax assets and liabilities included in the balance sheet are as follows:

	2002	2001
Deferred Tax Assets:		
Minimum tax credit carryforwards	$ 2,241,000	$ 1,727,000
State income taxes	648,000	663,000
Accrued bonuses	201,000	
Derivatives	83,000	
Other	109,000	68,000
Total Deferred Tax Assets	3,282,000	2,458,000
Deferred Tax Liabilities:		
Intangible drilling costs	22,666,000	21,259,000
Derivatives		1,655,000
Depreciation	742,000	641,000
Land held for investment	370,000	370,000
Other	589,000	677,000
Total Deferred Tax Liabilities	24,367,000	24,602,000
Net Deferred Tax Liabilities	$21,085,000	$22,144,000

A reconciliation of income tax computed at the federal statutory tax rate to the Company s effective tax rate is as follows:

	2002	2001	2000
Federal statutory income tax rate	34.0%	34.0%	34.0%
Percentage depletion	(6.3)	(1.2)	(1.5)
Section 29 credits	(15.8)	(3.0)	(3.1)
State taxes, net of federal benefits	1.5	1.0	1.0
Other	0.3	0.7	(0.1)
Effective tax rate	13.7%	31.5%	30.3%

Table of Contents

At December 31, 2002, Prima had minimum tax credit carryforwards of approximately $2,241,000, which may be carried forward indefinitely.

6. SEGMENT INFORMATION

The Company organizes its activities in operating segments that consist of 1) the acquisition, exploration, development and operation of oil and gas properties and the development, production and sale of oil and natural gas and 2) providing oilfield services for wells which it operates and for third parties. The Company s 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 the Company on the basis used by management in deciding how to allocate resources and in assessing performance. The following table sets forth revenues, operating earnings before income taxes, identifiable assets, depreciation, depletion and amortization expense and capital expenditures for the years ended December 31, 2002, 2001 and 2000. This information is presented on the basis used by management, which is the same basis used in the preparation of the Company s consolidated financial statements.

	2002	2001	2000
Revenues			
Oil & gas (including derivative effects)	$ 22,867,000	$ 50,983,000	$ 44,437,000
Oilfield services	10,325,000	12,207,000	9,912,000
	33,192,000	63,190,000	54,349,000
Corporate	597,000	1,214,000	1,464,000
Intersegment eliminations	(1,999,000)	(4,117,000)	(3,634,000)
Per financial statements	$ 31,790,000	$ 60,287,000	$ 52,179,000
Operating Earnings			
Oil & gas (including derivative effects)	$ 7,965,000	$ 34,913,000	$ 32,243,000
Oilfield services	1,094,000	2,083,000	844,000
	9,059,000	36,996,000	33,087,000
Corporate	(2,906,000)	(2,624,000)	(1,657,000)
Intersegment eliminations	(98,000)	(565,000)	
Per financial statements	$ 6,055,000	$ 33,807,000	$ 31,430,000
Identifiable Assets			
Oil & gas	$ 95,300,000	$ 100,200,000	$ 72,747,000
Oilfield services	6,322,000	7,218,000	6,044,000
	101,622,000	107,418,000	78,791,000
Corporate	40,305,000	28,026,000	26,109,000
Per financial statements	$ 141,927,000	$ 135,444,000	$ 104,900,000
Depreciation, Depletion and Amortization Expense			
Oil & gas	$ 9,710,000	$ 9,190,000	$ 6,150,000
Oilfield services	1,035,000	1,097,000	850,000
	10,745,000	10,287,000	7,000,000
Corporate	256,000	272,000	204,000

Per financial statements	$ 11,001,000	$ 10,559,000	$ 7,204,000
Capital Expenditures			
Oil & gas	$ 22,252,000	$ 35,248,000	$ 31,952,000
Oilfield services	868,000	1,539,000	1,235,000
	23,120,000	36,787,000	33,187,000
Corporate	274,000	419,000	378,000
Per financial statements	$ 23,394,000	$ 37,206,000	$ 33,565,000

Table of Contents

Total revenue by operating segment includes both sales to unaffiliated customers, as reported in the Company s consolidated income statement, and intersegment sales that are eliminated in consolidation, which are oilfield services provided for Company-operated wells. Oilfield services revenue is priced and accounted for consistently for both unaffiliated and intersegment sales.

Identifiable assets by operating segment are those assets that are used in the Company s operations in each segment. Corporate assets are principally cash, cash equivalents and available-for-sale securities.

Following is a table summarizing the percentage of sales made to each customer that accounted for over 10% of the Company s consolidated revenues. Although the loss of either of these customers could have a material adverse effect on Prima, the Company believes it would be able to locate other customers for the purchase of its production.

	2002	2001	2000
Duke Energy Field Services, Inc	33%	31%	36%
Valero Energy	29	16	21

7. COMMITMENTS AND CONTINGENCIES

Prima entered into a seven-year office space lease effective December 1, 2000. Office lease expense totaled $295,000, $282,000 and $187,000 for the years ended December 31, 2002, 2001 and 2000, respectively. The Company also entered into a twelve-month lease for compressor rental effective November 25, 2002. Future minimum annual rentals under these non-cancelable operating leases for the remainder of their terms are as follows:

Year ending December 31, 2003	$ 356,000
Year ending December 31, 2004	317,000
Year ending December 31, 2005	317,000
Year ending December 31, 2006	317,000
Year ending December 31, 2007	290,000
	$1,597,000

From time to time, the Company may be involved in litigation that arises in the ordinary course of business operations. As of the date of this report, the Company is not a party to any litigation that it believes could reasonably be expected to have a material adverse effect on its business or results of operations.

8. BENEFIT PLANS

Employee Stock Option Plans

Under Prima s 1993 Stock Incentive Plan and 2001 Stock Incentive Plan, 2,650,000 shares of the Company s common stock were reserved for issuance pursuant to options granted to key employees at exercise prices no less than fair market value on the dates of grant. Options granted to date under the plan vest ratably over three to five years, and expire ten years from the date of grant. At December 31, 2002, options to acquire 926,325 shares of the Company s common stock were outstanding. The exercise prices, which equaled the market prices of the stock on the dates of grant, range from $3.93 to $33.25 per share, with a weighted average price of $13.30 per share. As of December 31, 2002, the weighted average remaining contractual life of the options outstanding is 5 years, 1 month. A summary of options granted, exercised and outstanding during the three years ended December 31, 2002 is as follows:

Table of Contents

	Number of Shares	Weighted Average Exercise Prices
Balance at December 31, 1999	1,004,625	$ 5.50
Granted during 2000		
Exercised in 2000	(92,650)	5.62
Forfeited in 2000		
Outstanding at December 31, 2000	911,975	5.49
Granted during 2001	216,000	32.53
Exercised in 2001	(86,425)	5.01
Forfeited in 2001	(3,600)	9.39
Outstanding at December 31, 2001	1,037,950	11.14
Granted during 2002	171,500	25.36
Exercised in 2002	(174,125)	4.79
Forfeited in 2002	(109,000)	25.91
Outstanding at December 31, 2002	926,325	13.20
Exercisable at December 31, 2000	654,125	4.70
Exercisable at December 31, 2001	648,625	5.01
Exercisable at December 31, 2002	601,092	7.37

Non-Employee Directors Stock Option Plan

Under Prima s Non-Employee Directors Stock Option Plan, 225,000 shares of Prima s common stock were reserved for issuance pursuant to options granted to non-employee directors at exercise prices no less than fair market value on the dates of grant. This plan provides for each non-employee director to receive a grant of 22,500 options on the effective date of the plan, or upon election as a non-employee director if later. On each anniversary date of the initial grant, an additional 5,625 options are granted to each non-employee director. Options vest ratably over five years and expire ten years from the date of grant. At December 31, 2002, options to acquire 157,500 shares of the Company s common stock were outstanding under the plan, at exercise prices ranging from $6.67 to $32.33 per share. As of December 31, 2002, the weighted average remaining contractual life of the options outstanding is 7 years, 4 months. A summary of options granted, exercised and outstanding during the three years ended December 31, 2002 is as follows:

	Number of Shares	Weighted Average Exercise Prices
Balance at December 31, 1999	112,500	$ 7.30
Granted during 2000	61,875	25.36
Exercised during 2000	(4,500)	6.67
Forfeited during 2000	(23,625)	7.42
Outstanding at December 31, 2000	146,250	14.94
Granted during 2001	22,500	25.49
Exercised during 2001	(10,125)	7.02
Forfeited during 2001	(23,625)	10.86
Outstanding at December 31, 2001	135,000	17.86
Granted during 2002	22,500	20.52
Exercised during 2002		
Forfeited during 2002		

Outstanding at December 31, 2002	157,500	18.37
Exercisable at December 31, 2000	30,375	7.02
Exercisable at December 31, 2001	42,750	12.02
Exercisable at December 31, 2002	69,750	14.34

Table of Contents

Summary of Outstanding Options

The following table summarizes information about stock options outstanding at December 31, 2002 on a combined basis for the employee and non-employee directors plans:

Range of Exercise Prices		Stock Options Outstanding: Number Outstanding at 12/31/02	Stock Options Outstanding: Weighted-Average Remaining Contractual Life	Stock Options Outstanding: Weighted-Average Exercise Price	Stock Options Exercisable: Number Exercisable at 12/31/02	Stock Options Exercisable: Weighted-Average Exercise Price
$ 3.93	4.41	343,625	1.6	$ 4.19	343,625	$ 4.19
6.67	9.83	360,450	5.8	7.19	256,950	7.02
16.18	20.78	16,875	9.7	19.25		
21.75	26.38	139,000	8.6	24.78	21,375	22.94
29.90	33.25	223,875	8.2	32.45	48,892	32.07
			4.5	13.90		
		1,083,825			670,842	7.91

Employee Stock Ownership Plan

The Company has an Employee Stock Ownership Plan (ESOP), which is administered pursuant to a Trust Agreement. The ESOP is qualified under Section 401(a) of the Internal Revenue Code of 1986, as amended, and is for the benefit of all eligible employees of the Company. Company contributions are payable at a minimum rate of 5% of eligible salaries during the ESOP s fiscal year ending September 30, and are generally made quarterly. Through September 30, 1993, the ESOP provided for contributions to be used to purchase Prima common stock on the open market. Effective October 1, 1993, the ESOP was amended to allow fully-vested employees the option to direct the Trustees to diversify a portion of their investments by selling a limited portion of Prima common stock held in their account and investing the proceeds, as well as new contributions, in various diversified investment options. The ESOP benefits all full-time employees and provides for vesting in increments over six years. For the years ended December 31, 2002, 2001 and 2000, Prima expensed $339,000, $316,000 and $283,000, respectively, for its contributions to the ESOP.

9. TRANSACTIONS WITH RELATED PARTIES

The Company acquired oil and gas leases covering 26,680 net undeveloped acres in June 2000 from a company controlled by a director of Prima for a negotiated price of $12 per net acre, or a total of approximately $320,000. Additional acreage in the same general area was subsequently acquired from this director at cost. The aggregate amounts paid for these property interests, including the initial acquisition, totaled $3,000 in 2002, $290,000 in 2001 and $376,000 in 2000. The director, or entities controlled by him, reserved an overriding royalty interest in all acquired leases of 3% or less, depending on the net revenue interest of the leases, proportionately reduced to the working interest acquired. The disinterested members of the Board of Directors approved the transactions.

One of the Company s directors and one officer has participated, individually or through controlled entities, in oil and gas properties in which Prima has an interest. These working interest participations have been in prospects or properties originated or acquired by the Company. In some cases, the interests sold to affiliated and non-affiliated

Table of Contents

participants were sold on a promoted basis requiring these participants to pay a disproportionate share of well costs. All participations by directors and officers have been on terms no less favorable to the Company than believed to be obtainable from non-affiliated participants. Such joint participations may occur again from time to time in the future. All participations by officers or directors have been and will continue to be approved by the disinterested members of the Company s Board of Directors. At any point in time, there may be receivables or payables with officers and directors that arise in the ordinary course of business, as a result of participations in jointly held oil and gas properties. Amounts due to or from officers and directors resulting from billings of joint interest costs or receipts of production revenues on these properties are handled on terms pursuant to standard industry joint operating agreements which are no more or less favorable than similar transactions with unrelated parties.

Prima is a 6% limited partner in a real estate limited partnership that owns approximately 22 acres of undeveloped land in Phoenix, Arizona for investment and capital appreciation. The partnership owns the 22 acres free and clear. One of the general partners of the partnership is a company controlled by a brother of the Company s president. The Company participated on the same basis as the other limited partners. The disinterested members of the Company s Board of Directors approved the transaction. The carrying value of this investment at December 31, 2002 and 2001 was $257,000. During the three years ended December 31, 2002, the Company did not make any capital contributions to the partnership, nor did it receive any distributions therefrom.

10. SALE OF ASSETS

On March 5, 2002, Prima sold all of its producing wells in the Stones Throw coalbed methane project in the northern Powder River Basin, along with associated gathering system facilities and approximately 35,000 net undeveloped acres in the Stones Throw area. Net proceeds from the transaction totaled $13,514,000 after normal closing adjustments and were credited to the carrying value of oil and gas properties. These properties accounted for approximately 6.1% of Prima s total estimated proved oil and gas reserves and 4.5% of the related estimated present value of future net cash flows before income taxes, as of the end of 2001. The producing wells sold accounted for approximately 17% of Prima s net oil and gas production and 8% of its total oil and gas sales revenue before hedging effects during the first two months of 2002, and approximately 11% of net oil and gas production and 5% of total oil and gas sales revenue before hedging effects for the year 2001.

11. SUPPLEMENTARY OIL AND GAS INFORMATION

Prima s oil and gas operations are conducted entirely in the United States, primarily in the Rocky Mountain region. Certain information concerning these activities follows:

Costs Incurred Costs incurred in oil and gas property acquisition, exploration and development activities, and related depletion per equivalent units of production were as follows:

	2002	2001	2000
Acquisition costs:			
Unproved properties	$ 876,000	$ 2,114,000	$ 1,741,000
Proved properties	534,000	400,000	237,000
Exploration costs	5,685,000	1,620,000	642,000
Development costs	15,157,000	31,114,000	29,332,000
Total	$22,252,000	$35,248,000	$31,952,000
Depletion cost per equivalent Mcf of production	$ 0.92	$ 0.77	$ 0.54

Costs Not Being Amortized Oil and gas property costs not being amortized at December 31, 2002 consisted of $20,570,000 of leasehold costs and well costs for wells under evaluation. The Company anticipates that substantially all unevaluated costs will be classified as evaluated costs within three years.

Results of Operations Results of operations for oil and gas producing activities were as follows:

	2002	2001	2000
Revenues			
Oil and gas sales	$25,785,000	$44,548,000	$44,437,000
Gains (losses) on derivative instruments, net	(2,918,000)	6,435,000	
	22,867,000	50,983,000	44,437,000
Expenses			
Depletion of oil and gas properties	9,710,000	9,190,000	6,150,000
Lease operating expense	3,076,000	3,295,000	2,623,000
Ad valorem and production taxes	2,116,000	3,344,000	3,421,000
Impairment of natural gas swap		241,000	
	14,902,000	16,070,000	12,194,000
Income before income taxes	7,965,000	34,913,000	32,243,000
Income tax expense	1,083,000	10,998,000	9,770,000
Income from oil and gas producing activities	$ 6,882,000	$23,915,000	$22,473,000

Supplemental Oil and Gas Reserve Information (Unaudited)

The reserve information presented below is based on estimates of net proved reserves as of December 31, 2002 and 2001 that were prepared by the Company s engineers and audited by Netherland, Sewell and Associates, Inc., independent petroleum engineers, and estimates at the end of 2000 that were prepared or audited in part by Netherland, Sewell and Associates, Inc. and in part by Ryder Scott Company, independent petroleum engineers. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures. Oil and gas reserve engineering must be recognized as a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimates is a function of the quality of available data and engineering and geological interpretation and judgment. Results of drilling, testing and production after the date of the estimate may require revisions. Accordingly, reserve estimates are often materially different from the quantities of oil and natural gas that are ultimately produced.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are those proved reserves expected to be recovered through existing wells with existing equipment and operating methods.

Table of Contents

Analyses of Changes in Proved Reserves The following table sets forth information regarding the Company s estimated net total proved and proved developed oil and gas reserve quantities:

	2002		2001		2000	
	Oil (MBBLS)	Gas (MMCF)	Oil (MBBLS)	Gas (MMCF)	Oil (MBBLS)	Gas (MMCF)
Proved reserves:						
Beginning of year	3,394	115,222	3,729	154,172	3,268	124,111
Purchases of oil and gas reserves in place	5	899		2,388	1	5
Net exchanges of oil and gas reserves in place		(331)	10	(2,051)	14	125
Revisions of previous estimates	188	(17,744)	(611)	(44,495)	(259)	(5,969)
Extensions, discoveries and other additions	730	5,665	697	14,485	1,145	44,583
Production	(373)	(8,343)	(431)	(9,277)	(440)	(8,683)
Sales of oil and gas reserves in place		(7,928)				
End of year	3,944	87,440	3,394	115,222	3,729	154,172
Proved developed reserves:						
Beginning of year	2,949	69,168	2,945	77,385	2,521	54,079
End of year	3,115	66,245	2,949	69,168	2,945	77,385

Year-End Oil and Gas Prices Prima s average net realizable oil and natural gas prices at each year end, which were used in calculating reserve estimates, were as follows:

	2002	2001	2000
Natural gas (per Mcf)	$ 2.64	$ 1.94	$ 7.51
Oil (per barrel)	31.30	19.71	26.48

Standardized Measure The following table presents the standardized measure of discounted future net cash flows related to proved oil and gas reserves.

	2002	2001	2000
Future cash inflows	$354,617,000	$290,303,000	$1,256,037,000
Future production costs	(93,357,000)	(90,816,000)	(218,269,000)
Future development costs	(39,484,000)	(42,863,000)	(61,828,000)
Future net cash flows	221,776,000	156,624,000	975,940,000
10% discount factor	(92,933,000)	(64,719,000)	(399,888,000)
Discounted future income taxes	(37,564,000)	(25,104,000)	(204,931,000)
Standardized measure of discounted future net cash flows	$ 91,279,000	$ 66,801,000	$ 371,121,000

Table of Contents

A summary of changes in the standardized measure of discounted future net cash flows is as follows:

	2002	2001	2000
Standardized measure of discounted future net cash flows, beginning of year	$ 66,801,000	$ 371,121,000	$ 75,466,000
Sales of oil and gas, net of production costs and taxes	(21,136,000)	(34,057,000)	(38,392,000)
Net changes in prices and production costs	42,497,000	(469,638,000)	358,936,000
Extensions, discoveries, and improved recovery, less related costs	9,728,000	8,680,000	169,062,000
Development costs incurred during the year	7,518,000	19,920,000	12,128,000
Changes in estimated future development costs	(3,313,000)	11,381,000	922,000
Revisions of previous quantity estimates	(5,089,000)	(46,997,000)	(29,713,000)
Purchases of reserves in place	640,000	1,088,000	349,000
Net exchanges of reserves in place	(403,000)	(7,429,000)	3,409,000
Sales of reserves in place	(4,056,000)		
Other	1,360,000	(4,207,000)	(16,747,000)
Accretion of discount	9,191,000	37,112,000	7,547,000
Net changes in future income taxes	(12,459,000)	179,827,000	(171,846,000)
Standardized measure of discounted future net cash flows, end of year	$ 91,279,000	$ 66,801,000	$ 371,121,000

12. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited financial data for each quarter for the years ended December 31, 2002 and 2001.

	Three Months Ended			
	12/31/02	9/30/02	6/30/02	3/31/02
Year Ended December 31, 2002				
Revenues	$10,233,000	$7,432,000	$8,718,000	$ 5,407,000
Gross profit(1)	7,444,000	4,485,000	5,520,000	2,265,000
Income before income tax	3,421,000	1,226,000	2,470,000	(1,062,000)
Net income	2,936,000	1,026,000	1,990,000	(722,000)
Basic net income per share(2)	0.23	0.08	0.16	(0.06)
Diluted net income per share(2)	0.22	0.08	0.15	(0.06)

	Three Months Ended			
	12/31/01	9/30/01	6/30/01	3/31/01
Year Ended December 31, 2001				
Revenues	$10,454,000	$17,175,000	$14,188,000	$18,470,000
Gross profit(1)	6,858,000	14,061,000	11,016,000	14,776,000
Income before income tax and cumulative effect of change in accounting principle	3,369,000	10,242,000	8,221,000	11,975,000
Net income	2,354,000	7,067,000	5,671,000	8,676,000
Basic net income per share(2)	0.18	0.56	0.45	0.68

Diluted net income per share(2)	0.18	0.54	0.43	0.65

(1) Gross profit is computed as the excess of oil and gas sales, gains or losses on derivatives instruments, and revenues from oilfield services over operating expenses. Operating expenses include lease operating expense, ad valorem and production taxes, and oilfield services expenses.

(2) The sum of the individual quarterly net income (loss) per share may not agree with year-to-date net income (loss) per share as each period s computation is based on the weighted average number of common shares outstanding during the period.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Prima Energy Corporation has duly caused this Annual Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized, in Denver, Colorado on the 27th day of March, 2003.

PRIMA ENERGY CORPORATION

By: /s/ Richard H. Lewis

Richard H. Lewis, President

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report on Form 10-K has been signed below by the following persons in the capacities indicated and on the dates indicated.

Signature	Title	Date
/s/ Richard H. Lewis Richard H. Lewis	Chairman of the Board and President (Principal Executive Officer)	March 27, 2003
/s/ Neil L. Stenbuck Neil L. Stenbuck	Executive Vice President - Finance, Treasurer and Director (Principal Financial Officer)	March 27, 2003
/s/ Sandra J. Irlando Sandra J. Irlando	Vice President - Accounting (Principal Accounting Officer)	March 27, 2003
/s/ James R. Cummings James R. Cummings	Director	March 27, 2003
/s/ Douglas J. Guion Douglas J. Guion	Director	March 27, 2003
/s/ Catherine J. Paglia Catherine J. Paglia	Director	March 27, 2003
/s/ George L. Seward George L. Seward	Director	March 27, 2003

Table of Contents

CERTIFICATIONS

I, Richard H. Lewis, certify that:

1. I have reviewed this annual report on Form 10-K of Prima Energy Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this annual report;

4. The Registrant s other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the Registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the Registrant s disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the Evaluation Date); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The Registrant s other certifying officers and I have disclosed, based on our most recent evaluation, to the Registrant s auditors and the audit committee of Registrant s board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the Registrant s ability to record, process, summarize and report financial data and have identified for the Registrant s auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant s internal controls; and

6. The Registrant s other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 27, 2003

By: /s/ Richard H. Lewis

Richard H. Lewis,
President and Chief Executive Officer

Table of Contents

I, Neil L. Stenbuck, certify that:

1. I have reviewed this annual report on Form 10-K of Prima Energy Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this annual report;

4. The Registrant s other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the Registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the Registrant s disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the Evaluation Date); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The Registrant s other certifying officers and I have disclosed, based on our most recent evaluation, to the Registrant s auditors and the audit committee of Registrant s board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the Registrant s ability to record, process, summarize and report financial data and have identified for the Registrant s auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant s internal controls; and

6. The Registrant s other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 27, 2003

By: /s/ Neil L. Stenbuck

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

Table of Contents

INDEX TO 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 for the year ended June 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 for the quarter ended June 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 for the quarter ended 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 for the quarter ended June 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 for the year ended June 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 for the year ended 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 for the year ended 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 for the quarter ended 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 for the quarter ended March 31, 2002.)
21	Subsidiaries of the Registrant
23.1	Consent of Independent Auditors

23.2	Consent of Independent Reservoir Engineers