1998 1999 2000 2001 2002

EXCO

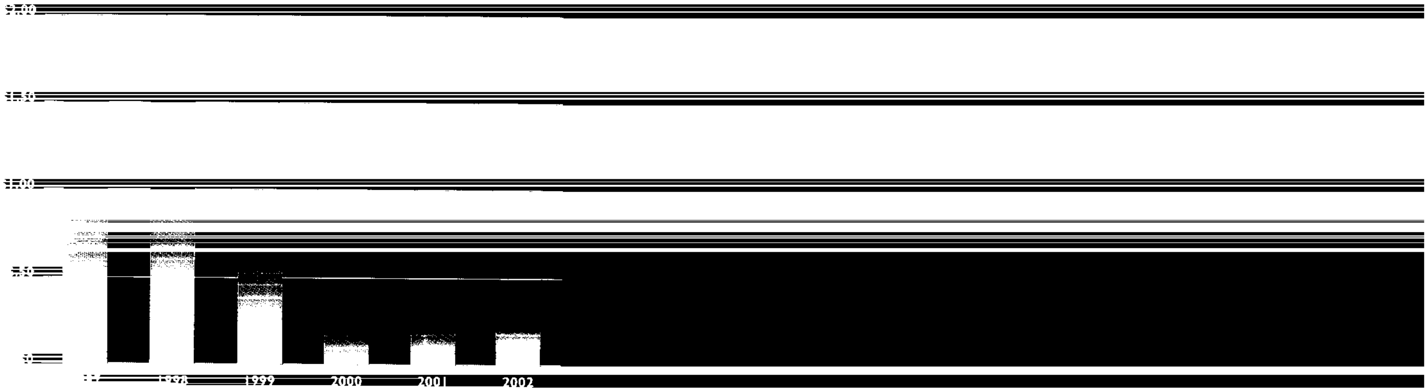
EXCO RESOURCES, INC.

2002

ANNUAL

REPORT

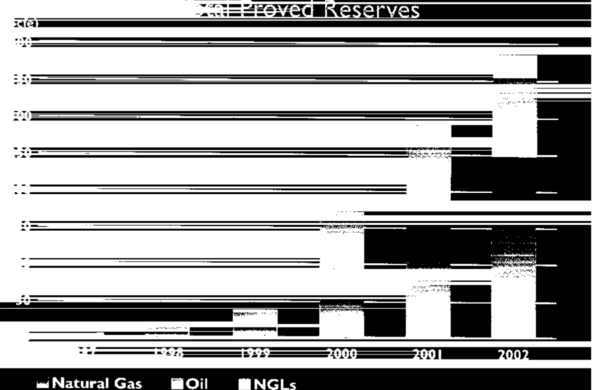
G&A per Mcfe*



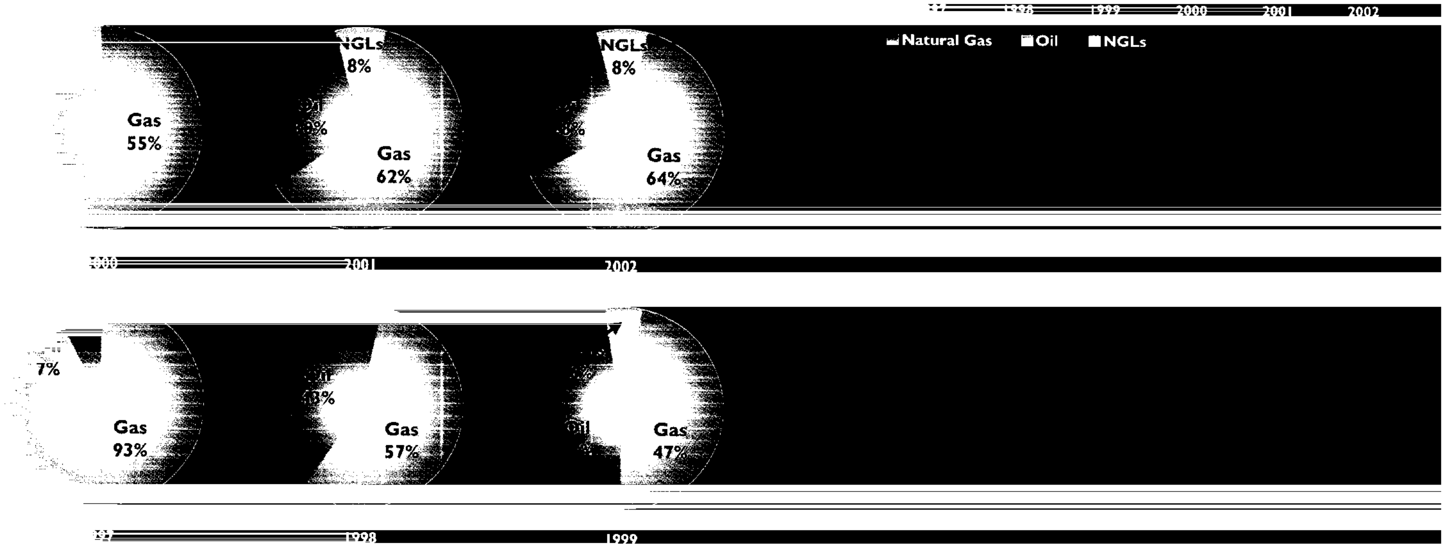
*General and administrative expenses per thousand cubic feet equivalent.

Production

Total Proved Reserves



Total Proved Reserve Mix



Dear Shareholders,

When we bought the controlling interests in EXCO in late December 1997 and early January 1998, we believed there existed an opportunity to acquire and consolidate domestic oil and gas assets by focusing on smaller asset and corporate acquisitions. Our competitors had raised a lot of money in both high yield debt and equity markets and were paying premium prices for larger transactions while overlooking smaller deals.

In the spring of 1998, crude oil markets collapsed and acquisition opportunities became more plentiful and attractive as some of our competitors began to suffer from too much debt at high interest rates. Although a number of competitors have liquidated, others still continue to struggle to survive. By mid-year 1998, EXCO decided to raise equity of its own to take advantage of the deal flow we had begun to see. Through a rights offering to shareholders, we sold common stock at the same price ($6.00) management had paid for their stock earlier in the year.

From that equity ($38 mm, approximately) and one more offering of preferred stock in 2001 ($105 mm, approximately), we have grown EXCO rapidly and effectively. The charts and tables included in this report depict some of our successes.

In our annual report last year, we predicted continuing fallout from Enron's financial collapse, and indeed our industry has been shaken by the events surrounding Enron's bankruptcy. Energy equities, including our own, have traded poorly and regulators have continued to mandate more accounting, reporting and compliance requirements. The cost of being public has continued to rise.

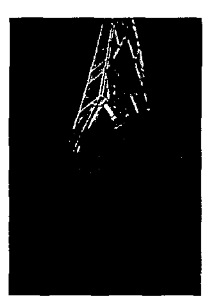
In August 2002, with our common stock trading at $14.75, I decided to propose to our shareholders the opportunity to liquidate their positions in EXCO when I offered to pay $17.00 per common share cash (subsequently increasing the offer to $18.00 per share) via a going private transaction. You will soon be asked to vote on that proposal.

If the proposal is approved by the required shareholder vote, this will be our final annual report to stockholders. For many of you, the ride from $6.00 per share to $18.00 will have been a successful trip. For others who may have purchased stock at a higher price, we hope the liquidity event will be a welcome one.

It has been our privilege to take this trip with you. Thank you for your support of EXCO Resources, Inc.

Sincerely,

Douglas H. Miller
Chairman and Chief Executive Officer



2002 TIMELINE

STOCK PRICE AT YEAR END

$17.48

ACQUISITIONS

$55.8 Million

EMPLOYEES AT YEAR-END

119

MAJOR EVENTS

APRIL

Acquired Canadian properties

NOVEMBER

Acquired DJ Basin properties

(In thousands, except prices, volumes and per share data)

RESULTS OF OPERATIONS

	Years Ended December 31,						2001-2002
	1997	*1998*	*1999*	*2000*	*2001*	***2002***	*Change*
Total revenues	$ 698	$ 2,075	$ 12,404	$ 30,659	$ 66,940	$ 73,103	9%
Net income (loss)	$ (205)	$ (511)	$ 4,665	$ 8,454	$ (39,347)	$ (967)	-98%
Earnings (loss) on common stock	$ (205)	$ (511)	$ 4,665	$ 8,454	$ (42,000)	$ (6,223)	-85%
Cash flow from operations *(a)*	$ (111)	$ (46)	$ 2,918	$ 14,148	$ 30,041	$ 26,328	-12%
Per basic share							
Earnings (loss) on common stock	$ (0.51)	$ (0.18)	$ 0.69	$ 1.23	$ (5.96)	$ (0.88)	-85%
Cash flow from operations	$ (0.28)	$ (0.02)	$ 0.44	$ 2.07	$ 4.26	$ 3.73	-13%
Per diluted common share							
Net income (loss)	$ (0.51)	$ (0.18)	$ 0.69	$ 1.18	$ (5.96)	$ (0.88)	-85%
Cash flow from operations *(a)*	$ (0.28)	$ (0.02)	$ 0.43	$ 1.98	$ 2.98	$ 2.10	-30%
Oil production (Mbbls)	14	53	208	433	967	1,268	31%
Natural gas production (Mmcf)	181	412	765	3,982	8,329	13,443	61%
NGL Production (Mbbls)	-	-	-	89	164	316	93%
Total production (Mmcfe) *(b)*	265	730	2,013	7,114	15,115	22,947	52%
Average realized price, including hedge results							
Oil (per Bbl)	$ 19.56	$ 12.01	$ 17.83	$ 27.39	$ 24.17	$ 20.50	-15%
Natural gas (per Mcf)	$ 2.14	$ 1.82	$ 2.07	$ 3.72	$ 4.20	$ 2.59	-38%
NGL (per Bbl)	$ -	$ -	$ -	$ 24.60	$ 17.70	$ 17.98	2%

FINANCIAL POSITION

	December 31,						2000 - 2001
	1997	*1998*	*1999*	*2000*	*2001*	***2002***	*Change*
Total assets	$ 1,270	$ 36,888	$ 50,932	$ 102,372	$ 191,056	$ 241,174	26%
Total debt and long-term liabilities	$ 15	$ -	$ -	$ 43,926	$ 57,355	$ 108,097	88%
Stockholders' equity	$ 927	$ 36,240	$ 40,880	$ 49,791	$ 120,379	$ 99,884	-17%
Book value per basic share	$ 2.30	$ 12.62	$ 6.10	$ 7.28	$ 17.08	$ 14.15	-17%
Book value per diluted share	$ 2.30	$ 12.61	$ 6.09	$ 6.99	$ 11.98	$ 7.97	-33%
Closing common stock price	$ 6.25	$ 7.25	$ 7.25	$ 15.63	$ 16.80	$ 17.48	4%
Closing 5% convertible preferred stock price	$ -	$ -	$ -	$ -	$ 17.51	$ 17.88	2%
Reserve information - SEC Case *(c)*							
Proved oil reserves (Mbbls)	58	963	2,744	12,378	14,853	18,035	21%
Proved natural gas reserves (Bcf)	4.3	7.7	16.5	94.4	183.7	249.3	36%
Proved NGL reserves (Mbbls)	-	-	370	465	3,616	5,091	41%
Total reserves (Bcfe) *(b)*	4.6	13.5	35.2	171.5	294.5	388.0	32%
Future net cash flow	$ 6,985	$ 14,379	$ 60,138	$ 848,692	$ 385,935	$1,082,242	180%
Present value at 10%	$ 4,028	$ 7,964	$ 36,977	$ 396,400	$ 189,155	$ 530,023	180%
Year-end NYMEX prices:							
Oil (per Bbl)	$ 17.64	$ 12.05	$ 25.60	$ 26.80	$ 19.84	$ 31.20	57%
Natural gas (per Mcf)	$ 2.26	$ 1.95	$ 2.33	$ 9.78	$ 2.57	$ 4.79	86%

At the end of 1997 and the beginning of 1998, new management bought a controlling interest in EXCO and redirected its focus.

(a) Cash flow before changes in working capital.
(b) Oil and NGLs converted to natural gas on the basis of one Bbl per six Mcf.
(c) Reserve information is based upon data contained in the reports of independent consulting petroleum engineers under SEC reporting parameters using prices and costs at the dates indicated before future income taxes.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A
AMENDMENT NO. 1

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2002

OR

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

For the Transition Period from to

Commission File Number 0-9204

EXCO RESOURCES, INC.

(Exact name of Registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	**74-1492779** (I.R.S. Employer Identification No.)
6500 Greenville Avenue, Suite 600, LB 17 **Dallas, Texas** (Address of principal executive offices)	**75206** (Zip Code)
(Registrant's telephone number, including area code)	**(214) 368-2084**

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

Securities registered pursuant to Section 12(g) of the Act:
Common Stock, Par Value $.02 Per Share
***5% Convertible Preferred Stock*, Par Value $.01 Per Share**
(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 twelve (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 ninety (90) days. YES ☒ NO ☐

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 this Form 10-K or any amendment of this Form 10-K. ☐

Indicate by check mark whether the Registrant is an accelerated filer (as defined in Rule 12b-2 of the Securities and Exchange Act of 1934). YES ☒ NO ☐

The number of shares of Common Stock, par value $.02 per share, of the Registrant outstanding on February 28, 2003, was 7,029,518 (excludes 248,434 treasury shares). The aggregate market value of the voting and non-voting common equity held by non-affiliates (all directors and executive officers are presumed to be affiliates) of the Registrant on June 28, 2002, was approximately $87.5 million based on the average of the closing bid and ask prices per share of the Common Stock on such date.

DOCUMENTS INCORPORATED BY REFERENCE

None

The Form 10-K of EXCO Resources, Inc. for the year ended December 31, 2002 is being amended to (i) amend Item 6.—Selected Financial Data in response to a comment letter received from the Securities and Exchange Commission (SEC), (ii) amend Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations in response to a comment letter received from the SEC, (iii) amend Item 8.—Financial Statements and Supplementary Data in response to a comment letter received from the SEC, and (iv) amend Item 15.—Exhibits, Financial Statement Schedules and Reports on Form 8-K to update the certifications of certain executive officers as of the date of this amendment. See Note 2. "Intangible Acquired Proved Leaseholds and Lease and Well Equipment" of the Notes to the Consolidated Financial Statements included in Item 8 for a discussion of certain reclassifications made to the Consolidated Balance Sheets. The Form 10-K is hereby amended and restated in its entirety (other than the Exhibits previously filed with Form 10-K).

TABLE OF CONTENTS

EXCO RESOURCES, INC.

PART I

ITEM 1. BUSINESS

General

EXCO Resources, Inc. is an independent energy company engaged in the acquisition, development and exploitation of oil and natural gas properties. Our primary areas of operations are onshore in Texas, Louisiana, Colorado, Mississippi and Alberta, Canada.

Since our present management team purchased a significant ownership interest in us in December 1997, we have achieved substantial growth through a strategy of acquiring proved oil and natural gas properties with development and exploitation potential. Between December 1997 and December 2002, we have completed 71 acquisitions for total net consideration of approximately $276 million, including 26 acquisitions for aggregate net consideration of approximately $55.8 million since January 1, 2002. Overall, our acquisitions have been made at an average cost of approximately $0.74 per Mcfe of proved reserves using our estimate of proved reserves as of the time of the acquisition. We now own interests in a number of established oil and natural gas producing basins that we intend to use as a platform for further growth. In addition, we believe that our properties provide us with significant growth potential from development and exploitation activities.

For this report, we converted Canadian dollars to U.S. dollars for balance sheet items including cash, oil and natural gas properties, and bank debt using the exchange rate at the end of the applicable period. The exchange rates of the Canadian dollar to the U.S. dollar were $0.628 and $0.636 at December 31, 2001 and 2002, respectively. For income statement items such as revenue, production costs, general and administrative costs, and interest, we converted Canadian dollars to U.S. dollars using the weighted average exchange rate across the applicable period. The weighted average exchange rates of the Canadian dollar to the U.S. dollar for the years 2001 and 2002 were $0.644 and $0.637, respectively. See Note 8 of the notes to our consolidated financial statements included in this annual report for certain information regarding our geographic operating areas.

Business Strategy

We intend to become a leading independent oil and natural gas acquisition, exploitation and production company. We plan to achieve asset, revenue and cash flow growth as a result of the acquisition and further development of producing oil and natural gas properties by implementing the following business strategies:

- *Acquire and Enhance Producing Oil and Natural Gas Properties.* We plan to take advantage of opportunities that currently exist in the United States and Canada to acquire producing oil and natural gas properties. We continue to focus our acquisition activities onshore in the mid-continent region of the United States and in Alberta, Canada to complement our existing properties and operations. We continue to review potential acquisitions in other regions of the United States and Canada if we believe they represent an opportunity for exploration, exploitation and development. We believe that numerous opportunities exist for us to acquire additional energy assets and to enhance the value of these assets through improved operating practices and by developing reserve potential.
- *Emphasize Exploitation and Development Activities.* We continue to exploit our existing oil and natural gas properties and we continue to conduct development evaluation and drilling on our oil and natural gas properties. We intend to concentrate on enhancement opportunities from activities such as infill drilling, recompletions, secondary recovery projects, repairs and

equipment changes. We may participate, from time to time, in a limited number of exploratory wells.

- *Corporate Efficiencies*. We plan to further maximize our corporate efficiencies through the development and operation of a larger asset base with the potential to limit increases in overhead in the future while operating an expanded asset base.
- *Financial Management*. We will continue to analyze our existing capital structure and financing requirements for future acquisitions and development to maintain appropriate levels of debt and equity.
- *Technology*. We plan to increase exploitation efforts, focusing on established geological trends where we can employ geological, geophysical and engineering expertise. We utilize 3-D seismic and advanced drilling technologies when appropriate.

In 2002, we evaluated approximately 166 acquisition opportunities with an aggregate estimated market value of over $3.3 billion. We made offers on properties totaling more than $1.4 billion and successfully completed the purchase of approximately $55.8 million of oil and natural gas properties and related assets. Offers varied in amounts from less than $10,000 to $450 million. We intend to pursue large acquisitions that will have a significant impact on our growth and smaller projects that have the potential for high levels of profitability. We prefer to acquire properties with shallow production, which offer lower geologic and mechanical risk of operations. In evaluating prospective acquisitions, we generally focus on estimates of future cash flows, rates of return and net present values expected to be generated by the acquired properties.

Developments During 2002

We acquired additional oil and natural gas properties in Alberta, Canada.

On April 29, 2002, Addison Energy Inc., our Canadian subsidiary, acquired oil and natural gas properties located in the Medicine River, Garrington, Gull Lake and Sylvan Lake areas in Alberta, Canada. The effective date of this transaction was January 1, 2002. As of January 1, 2002, estimated total proved reserves net to our interest included approximately 1.6 million Bbls of oil and NGLs, and 19.5 Bcf of natural gas. The purchase price was approximately $25.8 million or CDN $40.5 million ($24.7 million or CDN $36.3 million after contractual adjustments), funded with borrowings under our U.S. and Canadian credit agreements.

We acquired oil and natural gas properties in the DJ Basin of Colorado.

On November 1, 2002, we acquired oil and natural gas properties located in the DJ Basin in Colorado. The effective date of the transaction was October 1, 2002. As of October 1, 2002, estimated total proved reserves net to our interest included approximately 2.1 million Bbls of oil and NGLs, and 13.5 Bcf of natural gas from 111 gross (103 net) wells. Net daily production in September 2002 was approximately 630 Bbls of oil and NGLs, and 3.7 Mmcf of natural gas. The purchase price was approximately $22.0 million ($21.1 million after contractual adjustments), funded with borrowings of $19.7 million under our U.S. credit agreement and $1.4 million from surplus cash.

We had a loss of well control event while drilling the Leon #3.

We commenced drilling the Leon #3 well, in Pecos County, Texas, on February 16, 2002, which was completed as a producing natural gas well on September 8, 2002. The well was drilled and is being operated by another oil and natural gas company. While drilling operations were being conducted at 16,150 feet, a natural gas kick was taken and an underground blowout occurred. The well control problems resulted in a temporary loss of the wellbore back to 10,500 feet due to drill pipe being stuck in the hole. Fishing and other operations were eventually successful in freeing the drill pipe and the operator was able to recover the wellbore back to 16,150 feet. The well was subsequently completed at that depth and was placed on production. Our working interest in the well is 30.3%. We believe that the cost incurred for the well control event was covered under our well control insurance policy and claims have been submitted for these costs to our insurance carrier. The costs have not yet been reviewed by the insurance carrier. We have recorded as an accounts receivable approximately $684,000 at December 31, 2002, which represents our estimate of the insurance proceeds to be received by us.

The Leon #3 well was drilled as a replacement well to the Leon #2, which we operated. A portion of the cost to drill the Leon #3 will be reimbursed to us by our insurance carrier. The Leon #2 suffered a loss of well control event on October 31, 2001, while drilling at 15,878 feet. The loss of well control event resulted in pressure of approximately 6,700 pounds per square inch at the surface, at which time casing burst down hole. This resulted in the uncontrolled flow of natural gas at the surface and later an underground blowout. The well was eventually brought under control with help from well control specialists and was plugged on November 27, 2001. The total cost of the Leon #2 loss of well control event was, including a portion of the cost to drill the Leon #3, $5.6 million ($1.7 million net to our interest). We received $606,000 in insurance proceeds, net to our working interest, during 2002 and we have an accounts receivable of $1.1 million recorded at December 31, 2002, which represents our estimate of additional insurance proceeds to be received by us. This claim has been fully reviewed by the insurance carrier and we collected the $1.1 million in February 2003.

We had a loss of well control event while conducting workover operations on the Miami Corp. #35.

The Miami Corp. #35 well, in Cameron Parish, Louisiana, was not productive at the time we acquired it in 2000 due to downhole wellbore problems. In July 2002, we began workover operations in an attempt to return the well to production. On October 1, 2002, a loss of well control event occurred resulting in the release of approximately 20 Mmcf per day of natural gas and 2,800 barrels per day of formation water. No injuries or fires resulted from the loss of well control event. We contracted with well control specialists to assist with well control operations. Temporary production facilities were installed on the well and, as a result, a total of 325 Mmcf (244 Mmcf net to our interest) of natural gas was sold from the well between October 13, 2002, and November 25, 2002. The well was brought under control through conventional procedures on December 10, 2002. We continued to conduct workover operations on the well in an attempt to return the well to production. After being unable to recover downhole equipment that was stuck in the wellbore, in January 2003 we decided to temporarily abandon the well. We are evaluating several options including whether or not to sidetrack a portion of the wellbore, sell or transfer all or a portion of our interest to a third party, or to plug and abandon the well. The costs incurred for the loss of well control event and subsequent operations are estimated to be $3.2 million ($2.9 million net to our interest). We believe the cost incurred for the well control event was covered under our well control insurance policy and claims have been submitted for these costs to our insurance carrier. The costs have not yet been reviewed by the insurance carrier. We have recorded as an accounts receivable of $2.9 million at December 31, 2002, which represents our estimate of the insurance proceeds to be received by us.

We do not currently have well control insurance for our United States operations.

Our well control insurance policy, which covered both our United States and Canadian operations, expired during 2002 and our insurance carrier declined to renew our policy. We have obtained well control coverage for our Canadian drilling and workover activities effective as of February 12, 2003. As a result of the claims we have made on our well control insurance policy related to the Leon #2, the Leon #3 and the Miami Corp. #35, as well as general market conditions for insurance, we have been unable to obtain new well control insurance coverage for our United States operations on terms acceptable to us. We have delayed projects that we believe contain operational risks and we may continue to delay or postpone projects in the United States in the future if we are unable to obtain well control insurance for our United States operations on acceptable terms. The project delays could reduce our estimated production for 2003. We further expect that, if we are able to obtain such insurance for our United States operations, the rates used to determine the premiums will be substantially higher and that we will have to accept a higher level of risk through either higher deductibles or co-insurance clauses than provided in our previous policy.

We received an acquisition proposal from Douglas H. Miller, our chairman and chief executive officer, and we have entered into a merger agreement.

We have entered into a definitive agreement for the sale of the company to EXCO Holdings Inc., a company formed for that purpose by our chairman and chief executive officer, Douglas H. Miller, and his buyout group. The agreement provides that holders of our common stock, other than EXCO Holdings and its subsidiary, will receive cash of $18.00 per share and our holders of 5% convertible preferred stock will receive cash of $18.2625 per share if the transaction closes on or before June 15, 2003 and $18.00 per share thereafter. The 5% convertible preferred stock price difference is attributable solely to the unpaid accrued and unaccrued dividends for the 5% convertible preferred stock. A majority of the equity capital will be provided by Cerberus Capital Management, L.P. Cerberus Capital Management, L.P. is a New York based long-term investment fund manager with capital under management in excess of $8.5 billion.

In August 2002, Mr. Miller made a proposal to acquire us for $17.00 cash per common share and $17.00 cash per preferred share, adjusted for dividends payable before closing. Our board of directors thereafter formed a special committee of the board of directors, which hired Merrill Lynch & Co. to evaluate the proposal and assist the special committee in considering alternatives. During the course of this process, the price proposed by Mr. Miller was negotiated to the improved price reflected in the definitive agreement. Because a majority of our directors are participating in the acquisition, pursuant to Texas corporation law the agreement was submitted to our shareholders for approval without a recommendation of the full board, but based on the recommendation of the special committee. The special committee unanimously recommended that our shareholders approve the agreement and the board has approved its submission to the shareholders.

The transaction is subject to approval of our shareholders and customary closing conditions. The vote of holders of two-thirds of the outstanding shares of common stock, two-thirds of the outstanding shares of 5% convertible preferred stock and two-thirds of the outstanding shares of common stock and 5% convertible preferred stock voting as a single class is required to approve the transaction. We intend to hold a special meeting of the shareholders as soon as practicable. Completion of the transaction is expected late second quarter or early in the third quarter of 2003.

In conjunction with our special meeting of the shareholders, we will be mailing to shareholders following Securities and Exchange Commission, or SEC, clearance a proxy statement, which will more fully describe the terms of the transaction and contain other information required by the SEC with regard to the transaction and the purchaser group. We have filed with the SEC a Current Report on Form 8-K, dated March 12, 2003, which includes a copy of the Agreement and Plan of Merger that has been executed by the parties. Investors should refer to this document for the complete terms of the merger transaction.

If Mr. Miller or the Buyout Group were to acquire all or a substantial majority of our outstanding shares of our common stock and 5% convertible preferred stock held by other shareholders, our common stock and 5% convertible preferred stock could be de-listed from trading on the NASDAQ National Market or any other exchange or inter-dealer quotation system. If Mr. Miller or the Buyout Group were to acquire all or a substantial majority of the outstanding shares of common stock and 5% convertible preferred stock held by other shareholders, the common stock and the 5% convertible preferred stock could become eligible for termination of registration pursuant to Section 12(g)(4) of the Securities Exchange Act of 1934.

Litigation.

On August 7, 2002, litigation was filed in connection with Mr. Miller's proposed offer. The litigation was filed in the 160th State District Court in Dallas County, Texas and is captioned *Weiser v. EXCO Resources, Inc. et al.*, Cause No. 02-7065. The complaint was purportedly filed on behalf of our public shareholders and alleges that our current directors breached fiduciary duties owed to our shareholders in connection with Mr. Miller's offer. We are named as a defendant in the litigation. The litigation seeks declaratory and injunctive relief to enjoin our ability to engage in such a transaction with Mr. Miller and the recovery of any compensatory damages that would allegedly be sustained as a result of the transaction. We believe that the allegations contained in the complaint are without merit, and plan to vigorously contest and defend against the litigation.

On August 12, 2002, litigation was filed in the 162nd State District Court in Dallas County, Texas and is captioned *Birnbaum v. EXCO Resources, Inc., et al*, Cause No. 02-07396-I. The complaint was purportedly filed on behalf of our public shareholders and alleges that our current directors breached fiduciary duties owed to our shareholders in connection with Mr. Miller's offer. We are named as a defendant in the litigation. The litigation seeks declaratory and injunctive relief to enjoin our ability to engage in such a transaction with Mr. Miller and the recovery of any compensatory damages that would allegedly be sustained as a result of the transaction. We believe that the allegations contained in the complaint are without merit, and plan to vigorously contest and defend against the litigation.

On October 25, 2002, the *Weiser* and *Birnhaum* cases were consolidated in the 160th District Court. The proceedings have been stayed by the agreement of the parties until Mr. Miller files an offer to purchase us with the SEC or until the setting of a shareholder meeting to approve a merger.

Developments Since December 31, 2002

We entered into additional hedge agreements.

On January 17, 2003, we entered into four agreements to hedge additional natural gas volumes on a portion of our expected production for 2004. On January 29, 2003 and February 5, 2003, we entered into two agreements to hedge additional oil volumes on a portion of our expected production for 2004. The counterparties to these agreements were BNP Paribas and Bank One, financial lending institutions and members of our U.S. and Canadian bank groups. For more information concerning the additional hedging contracts, please review "Item 7A.—Quantitative and Qualitative Disclosures about Market Risk".

We have made additional acquisitions and dispositions of properties.

Since December 31, 2002, we have completed two oil and natural gas property acquisitions, one in Canada and one in the United States. Estimated total proved reserves net to our interest from these acquisitions included approximately 196,000 Bbls of oil and NGLs, and 3.7 Bcf of natural gas from 14 gross (5.8 net) wells. Net daily production from these properties is approximately 38 Bbls of oil and NGLs, and 742 Mcf of natural gas. The total purchase price for the acquisitions was approximately $5.5 million funded with borrowings under our Canadian credit agreement and from surplus cash.

We also have two additional oil and natural gas property acquisitions pending in Canada that we expect to close in April 2003. As of April 1, 2003, estimated total proved reserves net to our interest from these acquisitions is expected to be approximately 139,000 Bbls of oil and NGLs, and 2.8 Bcf of natural gas. Net daily production in January 2003 from these properties was approximately 45 Bbls of oil and NGLs, and 630 Mcf of natural gas. The total purchase price for the acquisitions is approximately $4.1 million, which we expect to fund with borrowings under our Canadian credit agreement and from surplus cash.

During January 2003, we sold two oil and natural gas properties in the United States. As of January 1, 2003, estimated total proved reserves net to our interest from these properties included approximately 391,000 Bbls of oil and NGLs, and 108,000 Mcf of natural gas from 8 gross (4.6 net) wells. Net daily production in December 2002 from these properties was approximately 256 Bbls of oil and NGLs, and 92 Mcf of natural gas. The total sales proceeds we received were approximately $1.9 million.

We also have two oil and natural gas property dispositions pending in the United States, subject to normal closing conditions. As of January 1, 2003, estimated total proved reserves net to our interest from these properties included approximately 174,000 Bbls of oil and NGLs, and 84,000 Mcf of natural gas. Net daily production in December 2002 from these properties was approximately 50 Bbls of oil and NGLs, and 22 Mcf of natural gas. The total sales proceeds we expect to receive from the sale of these properties are approximately $1.1 million.

Investment Considerations and Risk Factors

The risk factors noted in this section and other factors noted throughout this annual report, including those risks identified in "Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations," describe examples of risks, uncertainties and events that may cause our actual results to differ materially from those contained in any forward-looking statement. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, actual outcomes may vary materially from those included in this annual report.

Our revenue depends on oil and natural gas prices, which fluctuate.

Our future financial condition, access to capital, cash flow and results of operations depend upon the prices we receive for our oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are also beyond our control. In addition, natural gas prices in Canada and for production from the DJ Basin in Colorado have been and may continue to be subject to lower market prices primarily due to higher transportation costs and capacity restraints. Factors that affect the prices we receive for our oil and natural gas include:

- the level of domestic production;
- the availability of imported oil and natural gas;
- actions taken by foreign oil and natural gas producing nations;
- the cost and availability of transportation systems with adequate capacity;
- the cost and availability of other competitive fuels;
- fluctuating and seasonal demand for oil and natural gas;
- conservation and the extent of governmental regulation of production;
- weather;

- foreign and domestic government relations; and
- overall economic conditions.

Our ability to maintain or increase our borrowing capacity, to repay current or future indebtedness and to obtain additional capital on attractive terms depends substantially upon oil and natural gas prices.

Hedging our production may cause us to forego additional future profits.

To reduce our exposure to changes in the prices of oil and natural gas, we have entered into and may in the future enter into hedging arrangements for a portion of our oil and natural gas production. The hedges that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Hedging arrangements may expose us to the risk of financial loss in some circumstances, including the following:

- the counterparty to the hedging contract may default on its contractual obligations;
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received; or
- market prices may exceed the prices at which we are hedged, resulting in our need to make significant cash payments.

Our hedging activities could have the effect of reducing our revenues which, in turn, could have an adverse effect on our financial condition. As of December 31, 2002, the unrealized loss on our hedges was $7.1 million. As of February 28, 2003, our hedged volumes, based upon proved developed producing reserves at December 31, 2002, represent approximately 55%-65% of our forecasted oil production and 65%-75% of our forecasted natural gas production during 2003, and approximately 65%-70% of our forecasted oil production and 45%-50% of our forecasted natural gas production during 2004. These hedging arrangements may limit the benefit we would otherwise receive from increases in the prices for oil and natural gas. For more information about our hedging risk, please review "Item 7A.—Quantitative and Qualitative Disclosures about Market Risk".

We may be unable to acquire or develop additional reserves.

As is generally the case in the oil and natural gas industry, our success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are profitable to produce. Factors that may hinder our ability to acquire additional oil and natural gas reserves include competition, access to capital, prevailing oil and natural gas prices and the number of properties for sale. If we are unable to conduct successful development activities or acquire properties containing proved reserves, our total proved reserves will generally decline as a result of production. Also, our production will generally decline. If our production declines then our reserves will decline unless an increase in oil and natural gas prices offsets the decline. In addition, if our reserves and production decline then the amount we are able to borrow under our credit agreements will also decline. We cannot assure you that we will be able to locate additional reserves, that we will drill economically productive wells or that we will acquire properties containing proved reserves.

We cannot assure you that we will be successful in managing our growth.

We have completed several large acquisitions and the pursuit of additional acquisitions is a key part of our strategy. Our growth could strain our financial, technical, operational and administrative resources. Failure to manage our growth successfully could adversely affect our operations and net revenues through increased operating costs and revenues that do not meet our expectations. We cannot assure you that we can successfully integrate acquired oil and natural gas properties into our operations or achieve desired profitability.

We may encounter marketing obstacles.

Our ability to market our oil and natural gas production will depend upon the availability and capacity of natural gas gathering systems, pipelines and other transportation facilities. With the exception of a few small gathering systems, we do not currently operate our own pipelines or transportation facilities. As a result, we are dependent upon third parties to transport our products. Transportation space on the gathering systems and pipelines we utilize is occasionally limited or unavailable due to repairs or improvements to facilities or due to space being utilized by other companies that have priority transportation agreements. Our access to transportation options can also be affected by U.S. federal and state regulation and Canadian regulation of oil and natural gas production and transportation, general economic conditions and changes in supply and demand. These factors and the availability of markets are beyond our control. If market factors dramatically change, the financial impact on our revenues could be substantial and could adversely affect our ability to produce and market oil and natural gas.

Our Canadian operations may be adversely affected by currency fluctuations and economic and political developments.

We have significant oil and natural gas operations in Canada. Our Canadian operations are subject to the risk of fluctuations in the relative value of the Canadian and U.S. dollars. We have not hedged any currency risk exposure associated with our Canadian operations in prior periods. We are required to recognize foreign currency translation gains or losses related to our Canadian operations in our consolidated financial statements. Our Canadian operations may be adversely affected by political and economic developments, royalty and tax increases and other laws or policies in Canada, as well as U.S. policies affecting trade, taxation and investment in Canada.

Our Canadian properties and operations are subject to foreign regulations.

The oil and natural gas industry in Canada is subject to extensive legislation and regulation governing its operations. This legislation and regulation, enacted by various levels of government, impacts a number of areas, including royalties, land tenure, exploration, development, production, refining, transportation, marketing, environmental protection, exports, taxes, labor standards and health and safety standards. In addition, extensive legislation and regulation exists with respect to pricing and taxation of oil and natural gas and related products. Canadian governmental legislation and regulation may have a material effect on our operating results and may have a material adverse effect on our results of operations and our financial condition.

We may not identify all risks associated with the acquisition of oil and natural gas properties.

Generally, it is not feasible for us to review in detail every individual property involved in an acquisition. Our business strategy focuses on acquisitions of producing oil and natural gas properties. Any future acquisitions will require an assessment of recoverable reserves, future oil and natural gas prices, operating costs, potential environmental hazards and other liabilities and other similar factors. Ordinarily, our review efforts are focused on the higher-valued properties. However, even a detailed review of these properties and records may not reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We do not inspect every well that we acquire. Potential problems, such as deficiencies in the mechanical integrity of equipment or environmental conditions that may require significant remedial expenditures, are not necessarily observable even when we inspect a well. Even if we were able to identify problems with an acquisition, the seller may be unwilling or unable to provide effective contractual protection or indemnity against all or part of these problems. Even if a seller agrees to provide indemnity, we cannot assure you that the indemnity will be fully enforceable.

We have incurred significant debt that we may be unable to repay.

As of December 31, 2002, we have aggregate debt outstanding of approximately $97.9 million under our U.S. and Canadian credit agreements. This level of indebtedness could:

- increase our vulnerability to general adverse economic and industry conditions, especially declines in oil and natural gas prices;
- limit our ability to fund future acquisitions, capital expenditures and other general corporate requirements;
- require us to dedicate a material portion of our cash flow from operations to payments on our indebtedness;
- force us to sell assets to reduce our indebtedness;
- limit our flexibility in planning for, or reacting to, changes in our business and industry; or
- limit our ability to, among other things, borrow additional funds, sell assets and pay dividends.

Restrictive debt covenants limit our ability to finance our operations, fund our capital needs and engage in other business activities that may be in our interest.

Our U.S. and Canadian credit agreements contain significant covenants that, among other things, restrict our ability to:

- dispose of assets;
- incur additional indebtedness;
- repay other indebtedness;
- pay dividends;
- enter into specified investments or acquisitions;
- repurchase or redeem capital stock;
- merge or consolidate;
- engage in specified transactions with subsidiaries and affiliates; or
- other corporate activities.

Also, our credit agreements require us to maintain compliance with specified financial ratios. Our ability to comply with these ratios may be affected by events beyond our control. A breach of any of these covenants or our inability to comply with the required financial ratios could result in a default under our credit agreements.

We may be unable to obtain additional financing to implement our growth strategy.

The growth of our business will require substantial capital on a continuing basis. Because we have pledged substantially all of our assets as collateral under our U.S. and Canadian credit agreements, it may be difficult for us in the foreseeable future to obtain financing on an unsecured basis or to obtain additional secured financing other than purchase money indebtedness. If we are unable to obtain additional capital on satisfactory terms and conditions, we may lose opportunities to acquire oil and natural gas properties and businesses. Our failure to obtain any required additional financing may have a material adverse effect on our growth, cash flow and earnings.

We may be unable to overcome risks associated with our drilling activity.

Our drilling involves numerous risks, including the risk that we will not encounter commercially productive oil or natural gas reservoirs. We must incur significant expenditures to identify and acquire properties and to drill and complete wells. The costs of drilling and completing wells is often uncertain and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents, weather conditions and shortages or delays in the delivery of equipment. While we use advanced technology in our operations, this technology does not allow us to know conclusively prior to drilling a well that oil or natural gas is present or economically producible.

Acquisition, development and exploitation activities are associated with many uncertainties that could adversely affect our business, financial condition and results of operations.

Our future success will depend on the success of our acquisition, development and exploitation activities. Our decisions to purchase, develop or otherwise exploit properties or prospects will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses, and seismic and other information, the results of which are often inconclusive and subject to various interpretations.

We cannot control the development of the properties we own but do not operate.

As of December 31, 2002, we do not operate wells that represent approximately 17% of the present value of estimated future net revenues of our proved reserves. As a result, the success and timing of our drilling and development activities on those properties depend upon a number of factors outside of our control, including:

- the timing and amount of capital expenditures;
- the operators' expertise and financial resources;
- the approval of other participants in drilling wells; and
- the selection of suitable technology.

If drilling and development activities are not conducted on these properties, we may not be able to increase our production or offset normal production declines.

Our estimates of oil, natural gas and NGL reserves involve inherent uncertainty.

Numerous uncertainties are inherent in estimating quantities of proved oil, natural gas and NGL reserves, including many factors beyond our control. This annual report contains estimates of our proved oil, natural gas and NGL reserves and the PV-10 generated by the proved oil, natural gas and NGL reserves. These estimates are based upon reports of our independent petroleum engineers. These reports rely upon various assumptions, including assumptions required by the SEC, as to constant oil, natural gas and NGL prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. These estimates should not be construed as the current market value of our estimated proved reserves. The process of estimating oil, natural gas and NGL reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, engineering and economic data for each reservoir. As a result, the estimates are inherently imprecise evaluations of reserve quantities and future net revenue. Our actual future production, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil, natural gas and NGL reserves may vary substantially from those we have assumed in the estimates. Any significant variance in our assumptions could materially affect the quantity and value of reserves described in this annual report. In addition, our reserves may be revised downward or upward, based upon production history, results of future exploitation and development activities, prevailing oil and natural gas prices and other factors. A material decline in prices paid for our production can adversely impact the estimated volumes of our reserves.

We are exposed to operating hazards and uninsured risks.

Our operations are subject to the risks inherent in the oil and natural gas industry, including the risks of:

- fire, explosions and blowouts;
- pipe failure;
- abnormally pressured formations; and
- environmental accidents such as oil spills, gas leaks, ruptures or discharges of toxic gases, brine or well fluids into the environment (including groundwater contamination).

These events may result in substantial losses to us from:

- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigation;
- penalties and suspension of operations; or
- attorney's fees and other expenses incurred in the prosecution or defense of litigation.

As is customary in our industry, we maintain insurance against some, but not all, of these risks. We cannot assure you that our insurance will be adequate to cover these losses or liabilities. Further, with the turmoil in the commercial insurance industry as a result of the events of September 11, 2001, we cannot predict the continued availability of insurance at commercially acceptable premium levels or at all. We do not carry business interruption insurance. Losses and liabilities arising from uninsured or under-insured events may have a material adverse effect on our financial condition and operations.

Our well control insurance policy, which covered both our United States and Canadian operations expired in August 2002, and our insurance carrier declined to renew our policy. We have obtained well control coverage for our Canadian drilling and workover activities effective as of February 12, 2003. As a result of the claims we have made on our well control insurance policy related to the Miami Corp. #35, the Leon #2 and the drilling of the Leon #3, which was a replacement well for the Leon #2, as well as general market conditions for insurance, we have been unable to obtain new well control insurance coverage for our United States operations on terms acceptable to us. We have delayed projects that we believe contain operational risks and we may continue to delay or postpone projects in the United States in the future if we are unable to obtain well control insurance for our United States operations on acceptable terms. The project delays could reduce our estimated production for 2003. We further expect that, if we are able to obtain such insurance for our United States operations, that the rates used to determine the premium will be substantially higher than our prior policy and that we will have to accept a higher level of risk through either higher deductibles or co-insurance clauses than provided in our previous policy.

The producing wells that we own an interest in have, from time to time, experienced reduced or terminated production. These curtailments may result from mechanical failures, contract terms, pipeline and processing plant interruptions, market conditions and weather conditions. These curtailments may last from a few days to many months.

Our business exposes us to liability and extensive regulation on environmental matters.

Our operations are subject to numerous federal, state and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. Such laws and regulations not only expose us to liability for our own negligence, but may also expose us to liability for the conduct of others or for our actions that were in compliance with all applicable laws at the time those actions were taken.

Our business depends on a limited number of key personnel.

We are substantially dependent upon the skills of two key individuals within our management, Mr. Douglas H. Miller and Mr. T. W. Eubank. Both individuals have experience in acquiring, financing and restructuring oil and natural gas companies. They both previously served as senior management at Coda Energy, Inc., where they successfully implemented a strategy similar to our current strategy. We do not have employment agreements with these individuals or maintain key man insurance. The loss of the services of either one of these individuals could hinder our ability to successfully implement our business strategy.

We may have additional write-downs of our asset values.

We recorded pre-tax, non-cash ceiling test write-downs during 2001 of $28.7 million from our United States full cost pool and $20.9 million from our Canadian full cost pool. During the second quarter of 2002, we had an additional pre-tax, non-cash ceiling test write-down of $17.5 million from our Canadian full cost pool. Depending upon oil and natural gas prices in the future, we may be further required to write-down the value of our oil and natural gas properties if the present value of the after-tax future cash flows from our oil and natural gas properties falls below the net book value of these properties. Additional write-downs would negatively affect our earnings and net worth, and could result in a violation of covenants under our credit agreements.

We may not be permitted to pay cash dividends on our 5% convertible preferred stock in some circumstances. We could also be prevented in some circumstances from paying dividends on our common shares.

The terms of our existing credit agreements restrict our ability to pay cash dividends. Our ability to pay cash dividends will depend on criteria set forth in our credit agreements. If there is a default under our credit agreements, we will not be able to pay dividends on the shares of 5% convertible preferred stock. Even if our credit agreements permit us to pay cash dividends, we can make those payments only from our surplus (the excess of the fair value of our total assets over the sum of our liabilities plus our total paid-in share capital). In addition, we can pay cash dividends only if after paying those dividends we would be able to satisfy our liabilities as they become due. We cannot assure you that we will have any surplus.

Our 5% convertible preferred stock is subordinated to all our existing indebtedness and other liabilities and will not limit our ability to incur future indebtedness that will rank senior to our 5% convertible preferred stock.

Our 5% convertible preferred stock is subordinated to all of our indebtedness with respect to the payment of interest and amounts distributable upon our dissolution, liquidation or winding-up. The terms of our 5% convertible preferred stock do not limit the amount of indebtedness or other obligations that we may incur. Any indebtedness under our existing credit agreements will rank senior to our 5% convertible preferred stock.

Sales, or the availability for sale, of substantial amounts of our common stock could adversely affect the value of our 5% convertible preferred stock.

Sales of substantial amounts of common stock in the public market, and the availability of shares for future sale, including shares of our common stock issuable upon the conversion of shares of our 5% convertible preferred stock or upon exercise of outstanding options and warrants or other rights to acquire shares of our common stock, could adversely affect the prevailing market price of our common stock. This would adversely affect the value of our 5% convertible preferred stock and could impair our future ability to raise capital through an offering of our equity securities.

Our stock price may be volatile due to small public float.

Because the number of shares of our common stock that trades on a daily basis is relatively small, the sale of a substantial number of shares of our common stock, or conversion of another security into a substantial number of shares of our common stock, may adversely affect the market price of our common stock.

Our articles of incorporation may prevent a takeover attempt that you may favor.

Provisions in our articles of incorporation may delay, defer or prevent a tender offer or takeover attempt that you may consider to be in the best interest of our shareholders, including attempts that might result in a premium to be paid over the market price for the stock held by our shareholders. Our articles of incorporation permit our board to issue up to 5,010,131 additional shares of preferred stock and to establish, by resolution, one or more series of preferred stock and the powers, designations, preferences and participating, optional or other special rights of each series of preferred stock. The preferred stock may be issued on terms that are unfavorable to the holders of our common stock, including the grant of superior voting rights, the grant of preferences in favor of preferred shareholders in the payment of dividends and upon our liquidation and the designation of conversion rights that entitle holders of our preferred stock to convert their shares into our common stock on terms that are dilutive to holders of our common stock. The issuance of preferred stock in future offerings may make a takeover or change in control of us more difficult.

Our Oil, Natural Gas and NGL Reserves

The term "proved reserves" refers to the estimated quantities of oil, natural gas and NGLs that we may be able to recover in the future from known reservoirs. "Proved developed reserves" are proved reserves that are recoverable from known oil or natural gas reservoirs with existing equipment and operating methods. "Proved undeveloped reserves" are proved reserves requiring a relatively large development expense to make them recoverable from existing wells, or are proved reserves located in our undeveloped acreage.

We have not filed any estimates or included estimates in reports to any other federal authority or agency other than with the SEC since January 1, 2002. The following table summarizes our proved reserves at the dates shown, and was prepared according to the rules and regulations of the SEC:

	As of December 31,						
	2000	2001			2002		
	United States	United States	Canada	Total	United States	Canada	Total
Oil (Mbbls)							
Developed	8,148	7,555	3,414	10,969	**9,067**	**5,425**	**14,492**
Undeveloped	4,230	3,498	386	3,884	**3,214**	**329**	**3,543**
Total	12,378	11,053	3,800	14,853	**12,281**	**5,754**	**18,035**
Natural Gas (Mmcf)							
Developed	66,497	87,868	65,230	153,098	**115,222**	**92,512**	**207,734**
Undeveloped	27,947	22,388	8,174	30,562	**26,376**	**15,183**	**41,559**
Total	94,444	110,256	73,404	183,660	**141,598**	**107,695**	**249,293**
Natural Gas Liquids (Mbbls)							
Developed	465	774	2,470	3,244	**985**	**3,432**	**4,417**
Undeveloped	—	13	359	372	**112**	**562**	**674**
Total	465	787	2,829	3,616	**1,097**	**3,994**	**5,091**
Total (Mmcfe)	171,502	181,296	113,178	294,474	**221,866**	**166,183**	**388,049**
Prices utilized:							
Oil (per Bbl)	$ 24.82	$ 17.67	$ 18.02	$ 17.76	**$ 29.74**	**$ 29.16**	**$ 29.56**
Natural gas (per Mcf)	9.26	2.22	2.24	2.23	**4.27**	**3.91**	**4.12**
NGLs (per Bbl)	21.50	14.25	15.33	15.09	**20.71**	**22.30**	**21.96**
Pre-tax Present Value, discounted at 10% (PV-10) (in thousands)							
Developed	$ 288,864	$ 92,150	$ 76,127	$ 168,277	**$ 219,399**	**$ 218,013**	**$ 437,412**
Undeveloped	107,536	13,540	7,338	20,878	**64,433**	**28,178**	**92,611**
Total	$ 396,400	$ 105,690	$ 83,465	$ 189,155	**$ 283,832**	**$ 246,191**	**$ 530,023**
Standardized Measure (in thousands) (1)	$ 282,436	$ 83,085	$ 60,444	$ 143,529	**$ 152,923**	**$ 157,417**	**$ 310,340**

(1) The standardized measure represents the present value (using an annual discount rate of 10%) of estimated future net revenues from the production of proved reserves, after giving effect to income taxes.

The reserve estimates presented as of December 31, 2000, 2001 and 2002, have been prepared by Lee Keeling and Associates, Inc., independent petroleum engineers, Tulsa, Oklahoma, and are a part of their report on our oil and natural gas properties. Estimates of oil, natural gas and NGL reserves are projections based on engineering data and are forward-looking in nature. These reports rely upon various assumptions, including assumptions required by the SEC, such as constant oil, natural gas and NGL prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. These reports should not be construed as the current market value of our estimated proved reserves. The process of estimating oil and natural gas reserves is also dependent on geological, engineering and economic data for each reservoir. Because of the uncertainties inherent in the interpretation of this data, we cannot ensure that the reserves will ultimately be realized. Our actual results could differ materially. See also Note 15 of the notes to our consolidated financial statements included in this annual report for additional information regarding our oil, natural gas and NGL reserves, including the present value of future net revenues and the standardized measure.

The following table sets forth our proved reserves and PV-10 by area as of December 31, 2002:

	Total Proved Reserves (Bcfe)	PV-10 (In thousands)	Percent of PV-10
United States:			
Permian Basin	83	$ 102,896	20%
Gulf Coast	52	76,450	14%
Rockies	37	40,304	8%
Mid-Continent	26	33,692	6%
East Texas/North Louisiana	24	30,490	6%
Total U.S.	222	283,832	54%
Canada:			
Alberta	166	246,191	46%
Total U.S. and Canada	**388**	**$ 530,023**	**100%**

Our Production, Prices and Expenses

The following table summarizes for the periods indicated, our revenues (including hedge settlements), net production of oil, natural gas and NGLs sold, the average sales price per unit of oil, natural gas and NGLs, and costs and expenses associated with the production of oil, natural gas and NGLs:

	Year Ended December 31,						
	2000	2001			2002		
	United States	United States	Canada	Total	United States	Canada	Total
	(In thousands, except production and per unit amounts)						
Sales:							
Oil:							
Revenue	$ 11,846	$ 21,633	$ 1,739	$ 23,372	$ 16,330	$ 9,661	$ 25,991
Production sold (Mbbls)	433	887	80	967	869	399	1,268
Average sales price per Bbl	$ 27.39	$ 24.40	$ 21.71	$ 24.17	$ 18.78	$ 24.23	$ 20.50
Natural Gas:							
Revenue	$ 14,830	$ 29,558	$ 5,394	$ 34,952	$ 16,697	$ 18,077	$ 34,774
Production sold (Mmcf)	3,982	6,243	2,086	8,329	6,878	6,565	13,443
Average sales price per Mcf	$ 3.72	$ 4.73	$ 2.59	$ 4.20	$ 2.43	$ 2.75	$ 2.59
Natural Gas Liquids:							
Revenue	$ 2,193	$ 1,826	$ 1,087	$ 2,913	$ 1,227	$ 4,454	$ 5,681
Production sold (Mbbls)	89	96	68	164	74	242	316
Average sales price per Bbl	$ 24.60	$ 18.96	$ 15.92	$ 17.70	$ 16.66	$ 18.38	$ 17.98
Costs and Expenses:							
Average production cost per Mcfe	$ 1.32	$ 1.76	$ 0.85	$ 1.59	$ 1.52	$ 0.98	$ 1.27
General and administrative expense per Mcfe	$ 0.28	$ 0.34	$ 0.23	$ 0.32	$ 0.54	$ 0.40	$ 0.48
Depreciation, depletion and amortization per Mcfe	$ 0.69	$ 0.80	$ 1.50	$ 0.94	$ 0.76	$ 0.87	$ 0.81

Our Interest in Productive Wells

The following table quantifies our productive wells (wells that are currently producing oil or natural gas or are capable of production), including temporarily shut-in wells on December 31, 2002. The number of total gross oil and natural gas wells excludes any multiple completions. Gross wells refers to the total number of physical wells that we hold any working interest in, regardless of our percentage interest. A net well is not a physical well, but is actually a concept that reflects the actual total working interests we hold in all wells. We compute the number of net wells we own by totaling the percentage interests we hold in all our gross wells.

	Gross Wells (1)			Net Wells		
	Oil	Gas	Total	Oil	Gas	Total
United States:						
Colorado	28	111	139	9.0	102.7	111.7
Kansas	117	41	158	50.7	20.6	71.3
Louisiana	21	18	39	14.9	13.7	28.6
Mississippi	36	0	36	30.0	0.0	30.0
Nebraska	43	4	47	18.3	1.7	20.0
New Mexico	82	79	161	3.1	32.8	35.9
Oklahoma	50	36	86	41.6	7.8	49.4
Texas	878	170	1,048	162.6	87.0	249.6
Wyoming	72	9	81	15.1	5.2	20.3
Total	1,327	468	1,795	345.3	271.5	616.8
Canada:						
Alberta	226	211	437	97.0	157.4	254.4
Total	**1,553**	**679**	**2,232**	**442.3**	**428.9**	**871.2**

(1) As of December 31, 2002, we owned interests in 13 gross wells with multiple completions.

As of December 31, 2002, we were the operator of 744 gross (587.9 net) wells, which represented approximately 83% of the present value of estimated future net revenues (as of December 31, 2002) of our proved reserves.

Our Drilling Activities

We intend to concentrate our drilling activity on lower risk, development-type properties. The number and types of wells we drill will vary depending on the amount of funds we have available for drilling, the cost of each well, the size of the fractional working interests we acquire in each well and the estimated recoverable reserves attributable to each well.

The following table summarizes our approximate gross and net interests in the development wells drilled during the years indicated and refers to the number of wells completed at any time during the year, regardless of when drilling was initiated:

	Development Wells					
	Gross			Net		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2000 (1)	11	—	11	3.9	—	3.9
Year ended December 31, 2001						
United States	32	4	36	17.0	1.0	18.0
Canada	9	1	10	8.6	1.0	9.6
Total	41	5	46	25.6	2.0	27.6
Year ended December 31, 2002						
United States	9	1	10	5.4	.3	5.7
Canada	12	1	13	7.5	1.0	8.5
Total	**21**	**2**	**23**	**12.9**	**1.3**	**14.2**

(1) Information is for United States only. We acquired our Canadian operations in April 2001.

During the three year period ended December 31, 2002, we did not participate in the drilling of any exploratory wells. The drilling activities during 2002 in the United States referenced in the above table were conducted in Texas, Oklahoma, Louisiana and Kansas. The drilling activities during 2002 in Canada referenced in the above table were conducted in Alberta. On December 31, 2002, we did not have any drilling wells in progress in the U.S. On December 31, 2002, in Canada, we owned a 100% working interest in a well being drilled in the Lacombe area of Alberta. As of February 28, 2003, we had no wells drilling in the United States. In Alberta, Canada, we owned a 100% working interest in a well being drilled in the Pine Creek area as of February 28, 2003.

Summary of Our Development and Exploitation Projects

We are currently pursuing an active development and exploitation strategy. For the year 2003 we have budgeted up to $34.7 million for development drilling, recompletions, production facilities and other exploitation related projects to implement this strategy.

Set forth below are highlights of our other current and planned activities.

Vinegarone Field.

The Vinegarone Field is a natural gas field located in Val Verde County, Texas. We hold working interests ranging from less than 2% to 100% in 24 producing wells, of which we operate 21 wells. The wells produce from the Strawn and Swanson formations at depths from 10,000 to 10,500 feet. We currently plan to drill three wells and perform recompletion and/or commingling projects on four currently producing wells during 2003.

Gomez Field.

The Gomez Field is a natural gas field located in Pecos County, Texas. We hold working interests ranging from less than 1% to 73%. We operate five of the nine producing wells in which we have an interest. Production is primarily from three different zones: the Wolfcamp formation at approximately 15,800 feet; the Devonian formation at approximately 17,700 feet; and, the Ellenberger formation at approximately 22,000 feet. We completed the Leon #3 well to the Wolfcamp formation in September 2002. We have no development plans in this field during 2003.

Black Lake Field.

The Black Lake Field is a natural gas field located in Natchitoches Parish, Louisiana. We hold a 79.4% working interest and operate all 23 producing wells in this 16,936 acre unitized field. The wells produce from the Petit Lime formation at a depth of approximately 8,000 feet. We plan to drill one horizontal well and perform artificial lift projects on eight wells in this field during 2003.

Wattenberg Field.

The Wattenberg field is a natural gas field located in Weld County, Colorado. We acquired these properties during 2002. We hold working interests ranging from less than 3% to 100% in 111 producing wells, of which we operate 108 wells. The wells produce primarily from the Codell formation at a depth of approximately 7,000 feet. We currently plan to perform workover operations on 18 wells in this field during 2003.

Tiger Field.

The Tiger Field is an oil and natural gas field located in Jones and Perry Counties, Mississippi. We hold an 88.3% working interest in this field. We operate four wells that produce from the Hosston and Cotton Valley formations at depths from 14,300 to 15,400 feet. We plan to drill an infill well and perform workover operations on four wells during 2003.

Pecos Slope Field.

The Pecos Slope Field is a natural gas field located in Chaves County, New Mexico. We have working interests ranging from 12.5% to 100% in 29 wells, 23 of which we operate. Production is from the Abo formation at depths from 3,700 to 4,500 feet. We plan to drill two infill wells during 2003.

Garrington Field.

The Garrington Field is located in Alberta, Canada and produces oil and natural gas from Cretaceous and Mississippian formations at an average depth of 8,000 feet. We have an average working interest of 71% in 85 producing wells, 70 of which we operate. We plan to complete 19 exploitation projects in the Garrington Field during 2003, which include recompletions, lift optimizations and facility expansions. We also plan to drill three wells in this field during 2003.

Pine Creek Field.

The Pine Creek Field is an oil and natural gas field located in Alberta, Canada. We hold an average working interest of 87% in 35 producing wells, of which we operate 33. Pine Creek produces from Cretaceous formations at depths from 6,000 to 9,000 feet. We have identified three development locations to be drilled and eight exploitation projects to be performed in this field during 2003.

Caroline Field.

The Caroline Field produces oil and natural gas from Cretaceous formations at an average depth of 9,000 feet. It is located in Alberta, Canada and is adjacent to our Garrington Field. We have an average working interest of 84% in 32 producing wells, all of which we operate. We plan to complete four exploitation projects in 2003.

Westward Ho Field.

The Westward Ho Field is located in Alberta, Canada and produces oil and natural gas from Cretaceous and Mississippian formations at an average depth of 8,000 feet. It is also located adjacent to the Garrington Field. We have an average 64% working interest in 49 producing wells and operate

40 of those wells. We plan to drill three wells and complete 15 exploitation projects in the Westward Ho Field during 2003.

Lacombe Field.

The Lacombe Field, located in Alberta, Canada, produces natural gas from Cretaceous formations at depths from 800 to 5,500 feet. We operate seven of eight wells in this field. We have an average working interest of 88%. We have identified six development locations to be drilled and seven exploitation projects to be performed during 2003.

Our Developed and Undeveloped Acreage

Developed acreage are those acres spaced or assignable to producing wells. Undeveloped acreage are those acres that do not currently have completed wells capable of producing commercial quantities of oil or natural gas, regardless of whether the acreage contains proved reserves. The following table sets forth our developed and undeveloped acreage at December 31, 2002:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
United States:				
Colorado	13,342	8,556	2,680	1,497
Kansas	22,084	10,965	4,400	194
Louisiana	26,903	14,678	10,527	7,546
Mississippi	8,300	3,300	4,546	3,573
Montana	7,894	339	—	—
Nebraska	21,491	6,762	8,918	2,429
New Mexico	27,163	10,562	8,835	4,752
Oklahoma	14,192	4,671	1,563	793
Texas	78,089	32,795	30,947	16,467
Wyoming	8,390	2,788	5,780	2,741
Total	227,848	95,416	78,196	39,992
Canada:				
Alberta	147,338	103,540	89,510	65,553
Total	**375,186**	**198,956**	**167,706**	**105,545**

The primary terms of our oil and natural gas leases expire at various dates, generally ranging from one to five years. Almost all of our undeveloped acreage is "held by production," which means that these leases are active as long as we produce oil or natural gas from the acreage. Upon ceasing production, these leases will expire.

Sales of Producing Properties and Undeveloped Acreage

We evaluate our portfolio of properties on an ongoing basis to determine the economic viability of the properties and whether these properties enhance our objectives. During the course of normal business, we may dispose of producing properties and undeveloped acreage if we believe that it is in our best interest.

In 2002, we sold our interest in several producing oil and natural gas properties and a surplus natural gas processing plant in the United States for $3.7 million and a natural gas gathering system in Canada for $1.4 million. In 2001, we sold our interest in several producing oil and natural gas properties, including selected royalty and overriding royalty interests for $1.4 million. In 2000, we sold a portion of our interest in one group of producing oil and natural gas properties in Louisiana for $417,000, and a group of royalty interests in producing oil and natural gas properties located in various states for $491,000.

Our Products, Markets and Revenues

United States.

We produce oil, natural gas and NGLs. We do not refine or process the oil we produce. With the exception of our Black Lake Field in Louisiana, we do not refine or process a significant portion of the natural gas or NGLs we produce. At the Black Lake Field we operate a natural gas processing plant that is 100% dedicated to production from the field.

We sell the majority of the oil we produce under short-term contracts using market sensitive pricing. The majority of our contracts are based on New York Mercantile Exchange (NYMEX) pricing, which is typically calculated as the average of the daily closing prices of oil to be delivered one month in the future. We also sell a portion of our oil at F.O.B. field prices posted by the principal purchaser of oil where our producing properties are located. Our sales contracts are of a type common within the industry, and we usually negotiate a separate contract for each property. Generally, we sell our oil to purchasers and refiners near the areas of our producing properties.

We sell the majority of our natural gas under short-term contracts using market sensitive pricing. Our sales contracts are of a type common within the industry, and we frequently negotiate a separate contract for each property. We sell our natural gas to transmission and utility companies that have pipelines in the vicinity of our producing properties, to companies that will construct pipelines to our properties or, to third party natural gas marketing companies.

We sell our NGLs under both short-term and long-term contracts. We sell the NGLs to refiners and processors in the vicinity of our producing properties. Our sales contracts are of a type common within the industry, and we usually negotiate a separate contract for each property. Typically, the prices we receive for NGLs are based on the Oil Price Information Service (OPIS) index, less transportation and fractionating fees.

The availability of a ready market for oil, natural gas and NGLs and the prices of oil, natural gas and NGLs are dependent upon a number of factors that are beyond our control. These factors include, among other things:

- the level of domestic production and economic activity generally;
- the availability of imported oil and natural gas;
- actions taken by foreign oil producing nations;
- the cost and availability of natural gas pipelines with adequate capacity and other transportation facilities;
- the cost and availability of other competitive fuels, fluctuating and seasonal demand for oil, natural gas and refined products; and
- the extent of governmental regulation and taxation (under both present and future legislation) of the production, refining, transportation, pricing, use and allocation of oil, natural gas, refined products and substitute fuels.

Accordingly, in view of the many uncertainties affecting the supply and demand for oil, natural gas and refined petroleum products, we cannot accurately predict the prices or marketability of the oil, natural gas or NGLs from any producing well in which we have or may acquire an interest.

We cannot assure you that we will be able to market all the oil, natural gas or NGLs we produce. If our oil, natural gas or NGLs can be marketed, we cannot assure you that we can negotiate favorable price and contractual terms. Changes in oil or natural gas prices may significantly affect our revenues, cash flows, the value of our oil and natural gas properties, and the estimates of recoverable oil, natural gas and NGLs contained in our properties. Further, significant declines in the prices of oil or natural gas may have a material adverse effect on our business and on our financial condition.

We engage in oil and natural gas production activities in areas where, from time to time, the supply of oil or natural gas available for delivery exceeds the demand. In this situation, companies purchasing oil or natural gas in these areas reduce the amount of oil or natural gas that they purchase from us. If we cannot locate other buyers for our production or for any of our newly discovered oil or natural gas reserves, we may shut-in our oil or natural gas wells for periods of time. If this occurs, we may incur additional payment obligations under our oil and natural gas leases and, under certain circumstances, the oil and natural gas leases might be terminated.

Canada.

The majority of our Canadian oil is ultimately sold to Plains Marketing Canada, L.P. at market sensitive prices less applicable tariffs, trucking and quality adjustments.

At December 31, 2002, we were selling approximately 17,000 Mmbtus of our Canadian natural gas per day to two different purchasers at market sensitive prices. The remainder of our Canadian natural gas is sold to various purchasers at market sensitive prices.

Our NGLs are sold primarily to two different buyers under contracts which provide for index pricing less transportation and fractionation fees.

Revenues.

The following table sets forth the amount of our oil, natural gas and NGL sales (including hedge settlements) and the percent of these sales to total oil, natural gas and NGL revenues for the periods indicated (in thousands):

					Percent of Sales to Total Oil, Natural Gas and NGL Revenues		
Period Ended	**Oil Sales**	**Natural Gas Sales**	**NGL Sales**	**Total Oil, Natural Gas and NGL Sales**	**Oil**	**Natural Gas**	**NGLs**
Year ended December 31, 2000 (1)	$ 11,846	$ 14,830	$ 2,193	$ 28,869	41%	51%	8%
Year ended December 31, 2001							
United States	$ 21,633	$ 29,558	$ 1,826	$ 53,017	41%	56%	3%
Canada	1,739	5,394	1,087	8,220	21%	66%	13%
Total	$ 23,372	$ 34,952	$ 2,913	$ 61,237	38%	57%	5%
Year ended December 31, 2002							
United States	$ 16,330	$ 16,697	$ 1,227	$ 34,254	48%	49%	3%
Canada	9,661	18,077	4,454	32,192	30%	56%	14%
Total	**$ 25,991**	**$ 34,774**	**$ 5,681**	**$ 66,446**	**39%**	**52%**	**9%**

(1) Information is for United States only. We acquired our Canadian operations in April 2001.

Our Principal Customers

During 2002, sales of oil to Plains All American, Inc. and affiliates and sales of natural gas to Engage Energy America, LLC accounted for 21.6% and 14.5%, respectively, of our total oil and natural gas revenues. During 2001, sales of oil to Plains All American, Inc. and affiliates and sales of natural gas to Western Gas Resources, Inc. accounted for 14.5% and 11.8%, respectively, of our total oil and natural gas revenues. If we were to lose any one of our oil and natural gas purchasers, the loss could temporarily cease or delay production and sale of our oil and natural gas in that particular purchaser's service area. If we were to lose a purchaser, we believe we could identify a substitute purchaser. During 2002, several large wholesale purchasers of natural gas experienced significant downgrades in their credit ratings. As a result, many of these companies have either significantly reduced their level of natural gas purchases or have discontinued their purchases of natural gas. Although we do not believe that we have yet been significantly impacted by these changes, the loss of these large natural gas purchasers could have a detrimental effect on the natural gas market in general and on our ability to find purchasers for our natural gas. We typically do not require letters of credit or other forms of credit enhancement from our purchasers.

We Encounter Strong Competition

The oil and natural gas industry is highly competitive. We encounter strong competition from other independent operators and from major oil companies in acquiring properties, contracting for drilling equipment and securing trained personnel. Many of these competitors have financial and technical resources and staffs substantially larger than ours. As a result, our competitors may be able to pay more for desirable leases, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources will permit.

We are also affected by competition for drilling rigs and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and other exploitation activities and has caused significant price increases. We are unable to predict when, or if, such shortages may again occur or how they would affect our development and exploitation program.

Competition is also strong for attractive oil and natural gas producing properties, undeveloped leases and drilling rights, and we cannot assure you that we will be able to compete satisfactorily. Many large oil companies have been actively marketing some of their existing producing properties for sale to independent producers. We cannot assure you that we will be successful in acquiring any of these properties.

We are Affected by Various Laws and Regulations

U.S. Regulations

The availability of a ready market for oil and natural gas production depends upon numerous factors beyond our control. These factors include state and federal regulation of oil and natural gas production and transportation, as well as regulations governing environmental quality and pollution control, state limits on allowable rates of production by a well or proration unit, the amount of oil and natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities, and the marketing of competitive fuels. For example, a productive natural gas well may be "shut-in" because of an over-supply of natural gas or lack of an available natural gas pipeline in the areas in which we may conduct operations. State and federal regulations generally are intended to prevent waste of oil and natural gas, protect rights to produce oil and natural gas between owners in a common reservoir, control the amount of oil and natural gas produced by assigning allowable rates of production and control contamination of the environment. Pipelines and gas plants also are subject to the jurisdiction of various federal, state and local agencies.

Our sales of natural gas are affected by the availability, terms and costs of transportation. The rates, terms and conditions applicable to the interstate transportation of gas by pipelines are regulated by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act, as well as under Section 311 of the Natural Gas Policy Act. Since 1985, the FERC has implemented regulations intended to increase competition within the natural gas industry by making natural gas transportation more accessible to gas buyers and sellers on an open-access, non-discriminatory basis.

Our sales of oil are also affected by the availability, terms and costs of transportation. The rates, terms, and conditions applicable to the interstate transportation of oil by pipelines are regulated by the FERC under the Interstate Commerce Act. FERC has implemented a simplified and generally applicable rate-making methodology for interstate oil pipelines to fulfill the requirements of Title VII of the Energy Policy Act of 1992 comprised of an indexing system to establish ceilings on interstate oil pipeline rates. The FERC has announced several important transportation-related policy statements and rule changes, including a statement of policy and final rule issued February 25, 2000, concerning alternatives to its traditional cost-of-service rate-making methodology to establish the rates interstate pipelines may charge for their services. The final rule revises FERC's pricing policy and current regulatory framework to improve the efficiency of the market and further enhance competition in natural gas markets.

With respect to transportation of natural gas on or across the Outer Continental Shelf (OCS), the FERC requires, as a part of its regulation under the Outer Continental Shelf Lands Act (OCSLA), that all pipelines provide open and non-discriminatory access to both owner and non-owner shippers. Although to date the FERC has imposed light-handed regulation on offshore gathering facilities, it has the authority to exercise jurisdiction under the OCSLA over these type of gathering facilities, if necessary, to require non-discriminatory access by shippers to service. For those facilities transporting natural gas across the OCS that are not considered to be gathering facilities, the rates, terms and conditions applicable to this transportation are regulated by FERC under the NGA and NGPA, as well as the OCSLA. With respect to the transportation oil and condensate on or across the OCS, the FERC requires, as part of its regulation under the OCSLA, that all pipelines provide open and non-discriminatory access to both owner and non-owner shippers. Accordingly, the FERC has the authority to exercise jurisdiction under the OCSLA, if necessary, to require non-discriminatory access by shippers to service.

In the event we conduct operations on federal, state or Indian oil and gas leases, such operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes, royalty and related valuation requirements, and certain of such operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Bureau of Land Management (BLM) or Minerals Management Service (MMS) or other appropriate federal or state agencies.

Our OCS leases in federal waters are administered by the MMS and require compliance with detailed MMS regulations and orders. The MMS has promulgated regulations implementing restrictions on various production-related activities, including restricting the flaring or venting of natural gas. Under certain circumstances, the MMS may require any operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition and operations. On March 15, 2000, the MMS issued a final rule effective June 1, 2000, that amended its regulations governing the calculation of royalties and the valuation of crude oil produced from federal leases. Among other matters, this rule amended the valuation procedure for the sale of federal royalty oil by eliminating posted prices as a measure of value and relying instead on arm's length sales prices and spot market prices as market value indicators. Because we generally sell our production to third parties and therefore pay royalties on production from federal leases, we do not anticipate that this final rule will have any substantial impact on us.

The Mineral Leasing Act of 1920 (the Mineral Act) prohibits direct or indirect ownership of any interest in federal onshore oil and natural gas leases by a foreign citizen of a country that denies "similar or like privileges" to citizens of the United States. Such restrictions on citizens of a "non-reciprocal" country include ownership or holding or controlling stock in a corporation that holds a federal onshore oil and gas lease. If this restriction is violated, the corporation's lease can be canceled in a proceeding instituted by the United States Attorney General. Although the regulations of the BLM (which administers the Mineral Act) provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. We own interests in federal onshore oil and natural gas leases. It is possible that some of our shareholders may be citizens of foreign countries, and at some time in the future might be determined to be non-reciprocal under the Mineral Act.

The pipelines we use to gather and transport our oil and natural gas may be subject to regulation by the Department of Transportation (DOT) under the Hazardous Liquids Pipeline Safety Act of 1979, as amended (HLPSA). The HLPSA governs the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Where applicable, the HLPSA requires us and other pipeline operators to comply with regulations issued pursuant to HLPSA that are designed to permit access to and allow copying of records and to make certain reports available and provide information as required by the Secretary of Transportation.

The Pipeline Safety Act of 1992 (the Pipeline Safety Act) amends the HLPSA in several important respects. The Pipeline Safety Act requires the Research and Special Programs Administration (RSPA) of DOT to consider environmental impacts, as well as its traditional public safety mandate, when developing pipeline safety regulations. In addition, the Pipeline Safety Act mandates the establishment by DOT of pipeline operator qualification rules requiring minimum training requirements for operators, and requires that pipeline operators provide maps and records to RSPA. It also authorizes RSPA to require certain pipeline modifications as well as operational and maintenance changes. We believe our pipelines are in substantial compliance with the HLPSA and the Pipeline Safety Act where such regulations are applicable. However, we could incur significant expenses if new or additional safety measures are required.

U.S. Federal Taxation.

The federal government may propose tax initiatives that affect us. We are unable to determine what effect, if any, future proposals would have on product demand or our results of operations.

U.S. Environmental Regulation.

The exploration, development and production of oil and natural gas, including the operation of saltwater injection and disposal wells, is subject to various federal, state and local environmental laws and regulations. These laws and regulations can increase the costs of planning, designing, installing and operating oil and natural gas wells. Our domestic activities are subject to federal environmental laws and regulations, including, but not limited to:

- the Oil Pollution Act of 1990 (OPA);
- the Clean Water Act (CWA);
- the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA);
- the Resource Conservation and Recovery Act (RCRA);
- the Clean Air Act (CAA); and
- the Safe Drinking Water Act (SDWA).

Our domestic activities are also controlled by state regulations promulgated under comparable state statutes. We also are subject to regulations governing the handling, transportation, storage and disposal of naturally occurring radioactive materials that are found in our oil and natural gas operations. Civil and criminal fines and penalties may be imposed for non-compliance with these environmental laws and regulations. Additionally, these laws and regulations require the acquisition of permits or other governmental authorizations before undertaking certain activities, limit or prohibit other activities because of protected areas or species, can impose certain substantial liabilities for the cleanup of pollution, impose certain reporting requirements, and can require substantial expenditures for compliance.

Under OPA and CWA, our release of oil and hazardous substances into or upon waters of the United States, adjoining shorelines and wetlands, and offshore areas could result in our being held responsible for: (1) the costs of remediating a release, (2) administrative and civil penalties or criminal fines, or (3) OPA specified damages such as loss of use, and for natural resource damages. The extent of liability could be extensive depending upon the circumstances of the release. Liability can be joint and several and without regard to fault. The CWA also may impose permitting requirements for certain discharges of pollutants and requirements to develop Spill Prevention Control and Countermeasure Plans and Facility Response Plans to address potential discharges of oil into or upon waters of the United States and adjoining shorelines.

CERCLA and comparable state statutes, also known as Superfund laws, can impose joint, several and retroactive liability, without regard to fault or the legality of the original conduct, on specified classes of persons for the release of a "hazardous substance" into the environment. In practice, cleanup costs are usually allocated among various responsible parties. Liability can arise from conditions on properties where operations are conducted and/or from conditions at third party disposal facilities where wastes from operations were sent. Although CERCLA, as amended, currently exempts petroleum, (including oil, natural gas and NGLs) from the definition of hazardous substance, some similar state statutes do not provide such an exemption. Additionally, our operations may involve the use or handling of other materials that may be classified as hazardous substances under CERCLA and similar state statutes. We cannot assure you that the exemption will be preserved in any future amendments of the act.

RCRA and comparable state and local programs impose requirements on the management, including treatment, storage and disposal of both hazardous and nonhazardous solid wastes. Although we believe we have utilized operating and waste disposal practices that were standard in the industry at the time, hydrocarbons or other solid wastes may have been disposed or released on or under the properties we own or lease or on or under locations where such wastes have been taken for disposal. In addition, many of these properties have been owned or operated by third parties. We have not had control over such parties' treatment of hydrocarbons or other solid wastes and the manner in which such substances may have been disposed or released. We generate hazardous and nonhazardous solid waste in our routine operations. From time to time, proposals have been made that would reclassify certain oil and natural gas wastes, including wastes generated during pipeline, drilling and production operations, as "hazardous wastes" under RCRA, which would make these solid wastes subject to much more stringent handling, transportation, storage, disposal and clean-up requirements. Adoption of these proposals could have a significant impact on our operating costs. While state laws vary on this issue, state initiatives to further regulate oil and natural gas wastes could have a similar impact on our operations.

Oil and natural gas exploration and production, and possibly other activities, have been conducted at the majority of our properties by previous owners and operators. Materials from these operations remain on some of the properties and in some instances require remediation. In some instances we have agreed to indemnify the sellers of producing properties from whom we have acquired reserves against certain liabilities for environmental claims associated with the properties. We do not believe the costs to be incurred by us for compliance and remediating previously or currently owned or operated properties will be material, but we cannot guarantee that potential costs would not result in material expenditures.

If in the course of our routine oil and natural gas operations surface spills and leaks occur, including casing leaks of oil or other materials, we may incur penalties and costs for waste handling, remediation and third party actions for damages. Moreover, we are able to directly control the operations of only the wells that we operate. Notwithstanding our lack of control over wells owned by us but operated by others, the failure of the operator to comply with applicable environmental regulations may be attributable to us and may create legal liabilities for us.

We do not anticipate that we will be required in the near future to expend amounts that are material in relation to our total capital expenditures program by reason of environmental laws and regulations, but inasmuch as these laws and regulations are frequently changed and interpreted, we are unable to predict the ultimate cost of compliance. We are unable to assure you that more stringent laws and regulations protecting the environment will not be adopted or that we will not incur material expenses in complying with environmental laws and regulations in the future. If substantial liabilities to third parties or governmental entities are incurred, the payment of such claims may reduce or eliminate the funds available for project investment or result in loss of our properties. Although we maintain insurance coverage we consider to be customary in the industry, we are not fully insured against all of these risks, either because insurance is not available or because of high premiums. Accordingly, we may be subject to liability or may lose substantial portions of properties due to hazards that cannot be insured against or have not been insured against due to prohibitive premiums or for other reasons. The imposition of any of these liabilities on us may have a material adverse effect on our financial condition and results of operations.

OSHA and other regulations.

We are subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under the title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

Canadian Laws and Regulations

General.

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. The provincial government of Alberta has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, the prevention of waste and other matters. Although it is not expected that these controls and regulations will affect our operations in a manner materially different than they would affect other oil and natural gas companies of similar size, the controls and regulations should be considered carefully by investors in the oil and natural gas industry. Outlined below are some of the principal aspects of legislation and regulations governing the oil and natural gas industry. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing—Oil.

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The prices we receive depend, in part, on oil type and quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance and other contractual terms. Oil exports from Canada may be made pursuant to export contracts with terms not exceeding one year, in the case of light crude, and not exceeding two years, in the case of heavy crude, provided that an order approving any such export has been obtained from the National Energy Board (NEB). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB, which requires governmental approval.

Pricing and Marketing—Natural Gas.

In Canada, the price of natural gas sold in intraprovincial, interprovincial and international trade is determined by negotiations between buyers and sellers. The price we receive depends, in part, on natural gas quality, prices of competing natural gas and other fuels, distance to market, access to downstream transportation, length of contract term, weather conditions, the supply/demand balance and other contractual terms. Natural gas exported from Canada is subject to regulation by the NEB and the government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the government of Canada. Natural gas exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 cubic meters per day), must be made pursuant to a NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity, requires an exporter to obtain an export license from the NEB, which requires governmental approval.

The provincial government of Alberta also regulates the volume of natural gas which may be removed from Alberta for consumption elsewhere, based on such factors as reserve availability, transportation arrangements and market considerations.

Pipeline Capacity.

Although pipeline expansions are ongoing, the lack of firm natural gas pipeline capacity continues to affect the ability to produce and market natural gas production. The prorating of capacity on the interprovincial pipeline systems may also affect the ability to export oil.

The North American Free Trade Agreements.

On January 1, 1994, the North American Free Trade Agreement, NAFTA, among the governments of Canada, the U.S. and Mexico became effective. NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the U.S. or Mexico will be allowed, provided that any export restrictions do not:

- reduce the proportion of energy resource exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period);
- impose an export price higher than the domestic price; and
- disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

Land Tenure.

Oil and natural gas located in the western provinces is owned predominately by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses and permits for varying terms and conditions set forth in provincial legislation which may include requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are generally granted by lease on such terms and conditions as may be negotiated.

Royalties and Incentives.

In addition to federal regulation, each province in Canada has legislation and regulations that govern land tenure, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, the type of product being produced, well productivity, geographical location and field discovery date.

From time to time the federal and provincial governments in Canada have established incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. The trend in recent years has been for provincial governments to allow such programs to expire without renewal, and consequently few such programs are currently operative.

On October 13, 1992, the provincial government of Alberta implemented major changes in its royalty structure and created incentives for exploring and developing oil and natural gas reserves. The incentives created include: (1) a one year royalty holiday on new oil discovered on or after October 1, 1992; (2) incentives by way of royalty holidays and reduced royalties on reactivated, low productivity, vertical re-entry and horizontal wells; (3) introduction of separate par pricing for light/medium and heavy oil; and (4) a modification of the royalty formula structure through the implementation of the Third Tier Royalty with a base rate of 2% and a rate cap of 25% for oil pools discovered after September 30, 1992. The new oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%.

In Alberta, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is between 15% and 30%, in the case of new gas, and between 15% and 35%, in the case of old gas, depending upon a prescribed or corporate average reference price.

In Alberta, certain producers of oil or natural gas are also entitled to a credit against the royalties payable to the Alberta Crown by virtue of the Alberta royalty tax credit program (ARTC). The ARTC program is based on a price-sensitive formula, and the ARTC rate varies between 75%, at prices for oil below CDN $100 per cubic meter, and 25%, at prices above CDN $210 per cubic meter. The ARTC rate is applied to a maximum of CDN $2,000,000 of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from companies claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The ARTC rate is established quarterly based on the average "par price," as determined by the Alberta Resource Development Department for the previous quarterly period.

Oil and natural gas royalty holidays for specific wells and royalty reduction reduce the amount of Crown royalties paid by us to the provincial governments. The ARTC provides a rebate on Alberta Crown royalties paid in respect of eligible producing properties.

Canadian Environmental Regulation.

The oil and natural gas industry is currently subject to environment regulation pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and natural gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. As well, applicable environmental laws may impose remediation obligations with respect to property designated as a contaminated site upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any past or present owner, tenant or other person in possession of the site. Compliance with such legislation can require significant expenditures. A breach of such legislation may result in the imposition of material fines and penalties, the revocation of necessary licenses and authorizations and civil liability for pollution damage.

In Alberta, environmental compliance is governed by the *Alberta Environmental Protection and Enhancement Act*, AEPEA. In addition to replacing a variety of older statutes which related to environmental matters, the AEPEA imposes certain new environmental responsibilities on oil and natural gas operators in Alberta and in certain instances also imposes greater penalties for violations.

We will be taking such steps as required to ensure compliance with the AEPEA and similar legislation in other jurisdictions in which it operates. We believe that we are in material compliance with applicable environmental laws and regulations. We also believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards.

Title to Our Properties

When we acquire developed properties, we conduct a title investigation. However, when we acquire undeveloped properties, as is common industry practice, we usually conduct little or no investigation of title other than a preliminary review of local mineral records. We do conduct title investigations and, in most cases, obtain a title opinion of local counsel before we begin drilling operations. We believe that the methods we utilize for investigating title prior to acquiring any property are consistent with practices customary in the oil and natural gas industry and that our practices are adequately designed to enable us to acquire good title to properties. However, some title risks cannot be avoided, despite the use of customary industry practices.

Our properties are generally burdened by:

- customary royalty and overriding royalty interests;
- liens incident to operating agreements; and
- liens for current taxes and other burdens and minor encumbrances, easements and restrictions.

We believe that none of these burdens either materially detract from the value of our properties or materially interfere with property used in the operation of our business. Substantially all of our properties are pledged as collateral under our U.S. and Canadian credit facility.

Our Employees

As of December 31, 2002, we employed 119 persons (90 in the United States and 29 in Canada) of which 29 were involved in field operations and 90 were engaged in technical, office or administrative activities. None of our employees are represented by unions or covered by collective bargaining agreements. To date, we have not experienced any strikes or work stoppages due to labor problems, and we consider our relations with our employees to be good. We also utilize the services of independent consultants on a contract basis.

Our Officers

Douglas H. Miller, 55, became our Chairman and Chief Executive Officer in December 1997. Mr. Miller was Chairman of the Board and Chief Executive Officer of Coda Energy, Inc., an independent oil and natural gas company, from October 1989 until November 1997 and served as a director of Coda from 1987 until November 1997.

T. W. Eubank, 60, became our President, Treasurer and a director in December 1997. Mr. Eubank was a consultant to various private companies from February 1996 to December 1997. Mr. Eubank served as President of Coda from March 1985 until February 1996. He was a director of Coda from 1981 until February 1996.

J. Douglas Ramsey, Ph.D., 42, became our Chief Financial Officer and a Vice President in December 1997. Dr. Ramsey has been one of our directors since March 1998. Dr. Ramsey most recently was Financial Planning Manager of Coda and worked in various capacities for Coda from 1992 until 1997. Dr. Ramsey also taught finance at Southern Methodist University.

Charles R. Evans, 49, joined us in February 1998, became a Vice President in March 1998, and was named our Chief Operating Officer in December 2000. Mr. Evans graduated from Oklahoma University with a B.S. degree in Petroleum Engineering in 1976. After working for Sun Oil Co., he joined TXO Production Corp. in 1979 and was appointed Vice President of Engineering and Evaluation in 1989. In 1990, he was named Vice President of Engineering and Project Development for Delhi Gas Pipeline Corporation, a natural gas gathering, processing and marketing company. Mr. Evans served as Director—Environmental Affairs and Safety for Delhi until December 1997.

Richard E. Miller, 49, became our General Counsel, General Land Manager and Secretary of EXCO in December 1997 and became a Vice President in July 2000. Mr. Miller was a senior partner and head of the Energy Section of Gardere & Wynne, L.L.P., a Dallas based law firm, from December 1991 to September 1994. Mr. Miller practiced law as a sole practitioner from September 1994 to December 1997.

J. David Choisser, CPA, 52, joined us in October 2001 and became our Chief Accounting Officer in November 2001, and a Vice President in February 2002. He began his career in 1972 with Deloitte Haskins & Sells (now Deloitte & Touche). During the past 25 years, he has served in various financial and accounting management capacities with several energy and energy-related companies, including Delhi Gas Pipeline Corporation, Coda Energy, Inc., Belco Oil & Gas Corp., and The Meridian Resource Corporation. He most recently served as Vice President—Finance of Noble Denton & Associates, Inc., an offshore engineering and marine consulting company.

W. Andy Bracken, CPA, 38, joined us in October 1998 and became our Controller in April 2000. Mr. Bracken was a trust and operational internal auditor for Bank One, Louisiana, N.A. from April 1991 to April 1996 and NationsBank, N.A. from April 1996 to April 1997. He then served as an accounting manager for Bank One, Texas, N.A. from April 1997 to October 1998.

Richard L. Hodges, 51, became one of our Vice Presidents in October 2000. He began his career with Texaco Inc. and has served in various land management capacities with several independent oil and gas companies during the past 27 years. He served as Vice President of Land for Central Resources, Inc. until the acquisition by EXCO of the Central properties in September 2000.

John D. Jacobi, 49, became one of our Vice Presidents in February 1999. In 1991, he co-founded Jacobi-Johnson Energy, Inc., an independent oil and natural gas producer, and served as its President until January 1997. He served as the Vice President and Treasurer of Jacobi-Johnson from January 1997 until May 8, 1998, when the company was sold to EXCO.

Daniel A. Johnson, 51, became one of our Vice Presidents in February 1999. In 1991, he co-founded Jacobi-Johnson Energy, Inc., an independent oil and natural gas producer. He served as its President from January 1997 until the company was sold to EXCO on May 8, 1998.

James M. Perkins, Jr., 60, joined us as one of our Vice Presidents in February 2002. He has 38 years of experience in the oil and gas industry with major integrated oil companies, including ARCO and Texaco, and several independents, including Lyco Energy, Dorchester Exploration and General American Oil Company of Texas. He served these companies in various land management and executive positions.

Glossary of Selected Oil and Natural Gas Terms

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry and this annual report.

"Bbl." One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

"Bcf." One billion cubic feet of natural gas.

"Bcfe." One billion cubic feet equivalent calculated by converting 1 Bbl of oil or NGLs to 6 Mcf of natural gas.

"infill drilling." Drilling of a well between known producing wells to better exploit the reservoir.

"Mcf." One thousand cubic feet of natural gas.

"Mcfe." One thousand cubic feet equivalent calculated by converting 1 Bbl of oil or NGLs to 6 Mcf of natural gas.

"Mbbl." One thousand stock tank barrels.

"Mmcf." One million cubic feet of natural gas.

"NGLs." The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

"overriding royalty interest." An interest in an oil and/or natural gas property entitling the owner to a share of oil and natural gas production free of costs of production.

"present value of estimated future net revenues" or "PV-10." The present value of estimated future net revenues is an estimate of future net revenues from a property at December 31, 2002, at its acquisition date, or as otherwise indicated, after deducting production and ad valorem taxes, future capital costs and operating expenses, but before deducting federal income taxes. The future net revenues have been discounted at an annual rate of 10% to determine their "present value." The present value is shown to indicate the effect of time on the value of the net revenue stream and should not be construed as being the fair market value of the properties. Estimates have been made using constant oil, natural gas and NGL prices and operating costs at December 31, 2002, at its acquisition date, or as otherwise indicated. We believe that the present value of estimated future net revenues before income taxes, while not in accordance with generally accepted accounting principles, is an important financial measure used by investors and independent oil and natural gas producers for evaluating the relative significance of oil and natural gas properties and acquisitions.

"royalty interest." An interest in an oil and/or natural gas property entitling the owner to a share of oil and natural gas production free of costs of production.

Available Information

We do not currently maintain an active Internet website. Accordingly, we do not make our filings with the SEC available on or through a website. We will provide paper copies of our filings (excluding exhibits) free of charge upon request. Please mail your request to: EXCO Resources, Inc., 6500 Greenville Avenue, Suite 600, LB 17, Dallas, TX 75206, Attention: Investor Relations. You may also call us at (214) 368-2084 and ask to speak to investor relations.

ITEM 2. PROPERTIES

General

We lease approximately 18,500 square feet of office space in Dallas, Texas, 7,450 square feet in Denver, Colorado, and 19,000 square feet in Calgary, Alberta for our corporate offices. The leases expire December 31, 2005, May 31, 2004, and August 31, 2007, respectively, and require monthly rental payments of approximately $23,700, $12,400, and $28,700, respectively. We also have small offices in Eastland, Texas, Tyler, Texas and Tulsa, Oklahoma.

Other

We have described our oil and natural gas properties, oil, natural gas and NGL reserves, acreage, wells, production and drilling activity in "Item 1. Business" beginning on page 1 of this annual report.

ITEM 3. LEGAL PROCEEDINGS

We are a defendant in various lawsuits. We do not believe that any outcome of such lawsuits or other issues would have a material adverse effect on our financial position.

On August 7, 2002, litigation was filed in connection with Mr. Miller's proposed offer. The litigation was filed in the 160th State District Court in Dallas County, Texas, and is captioned *Weiser v. EXCO Resources, Inc., et al.*, Cause No. 02-7065. The complaint was purportedly filed on behalf of our public shareholders and alleges that our current directors breached fiduciary duties owed to our shareholders in connection with Mr. Miller's offer. We are named as a defendant in the litigation. The litigation seeks declaratory and injunctive relief to enjoin our ability to engage in such a transaction with Mr. Miller and the recovery of any compensatory damages that would allegedly be sustained as a result of the transaction. We believe that the allegations contained in the complaint are without merit, and plan to vigorously contest and defend against the litigation.

On August 12, 2002, litigation was filed in the 162nd State District Court in Dallas County, Texas, and is captioned *Birnbaum v. EXCO Resources, Inc., et al*, Cause No. 02-07396-I. The complaint was purportedly filed on behalf of our public shareholders and alleges that our current directors breached fiduciary duties owed to our shareholders in connection with Mr. Miller's offer. We are named as a defendant in the litigation. The litigation seeks declaratory and injunctive relief to enjoin our ability to engage in such a transaction with Mr. Miller and the recovery of any compensatory damages that would allegedly be sustained as a result of the transaction. We believe that the allegations contained in the complaint are without merit, and plan to vigorously contest and defend against the litigation.

On October 25, 2002, the *Weiser and Birnbaum* cases were consolidated in the 160th District Court. The proceedings have been stayed by the agreement of the parties until Mr. Miller files an offer to purchase us with the SEC or until the setting of a shareholder meeting to approve a merger.

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

During the last three months of the year ended December 31, 2002, we did not submit any matter to a vote by our shareholders through the solicitation of proxies or otherwise.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED SHAREHOLDER MATTERS

Market Information for Our Common Stock

Our common stock is quoted on the Nasdaq National Market System (Nasdaq NMS) under the symbol "EXCO." The following table sets forth the high and low bid prices from January 1, 2001 through December 31, 2002, based upon quotations periodically published on the Nasdaq NMS. All price quotations represent prices between dealers, without accounting for retail mark-ups, mark-downs or commissions, and may not represent actual transactions.

	High	Low
Year ended December 31, 2001:		
First Quarter	$ 20.13	$ 15.25
Second Quarter	21.06	18.19
Third Quarter	17.10	14.45
Fourth Quarter	16.72	13.26
Year ended December 31, 2002:		
First Quarter	$ 16.75	$ 14.94
Second Quarter	17.40	14.79
Third Quarter	16.61	14.60
Fourth Quarter	17.46	16.35

The bid price for our common stock was $17.56 on March 18, 2003.

Our Shareholders

According to our transfer agent, Continental Stock Transfer & Trust Company, there were approximately 725 holders of record of our common stock on February 28, 2003 (including nominee holders such as banks and brokerage firms who hold shares for beneficial holders).

Our Dividend Policy

We have not paid any cash dividends on our common stock, and do not anticipate paying cash dividends on our common stock in the foreseeable future. In addition, our credit agreements currently prohibit us from paying dividends on our common stock. Our credit agreements do not prohibit us from paying dividends on our 5% convertible preferred stock. We anticipate that any income generated in the foreseeable future that is in excess of our dividend payments on our 5% convertible preferred stock will be retained for the development and expansion of our business. Our future dividend policy is subject to the discretion of the board of directors and will depend upon a number of factors, including future earnings, debt service, capital requirements, restrictions in our credit agreements, business conditions, our financial condition and other factors that our board of directors deems relevant.

Our Equity Compensation Plans Information

For information on our equity compensation plans, please see "Item 11. Executive Compensation."

ITEM 6. SELECTED FINANCIAL DATA

The following table presents our selected historical financial data. You should read this financial data in conjunction with our "Management's Discussion and Analysis of Financial Condition and Results of Operations," our consolidated financial statements, the notes to our consolidated financial statements and the other financial information, included in this annual report. This information does not replace the consolidated financial statements. In our opinion, the data we have presented reflects all adjustments we consider necessary for a fair presentation of the results for the periods. We have completed numerous acquisitions since 1997 that materially impact the comparability of this data between periods.

	Year Ended December 31,				
	1998	1999	2000	2001	2002
	(In thousands, except per share amounts)				
Statement of Operations Data:					
Revenues:					
Oil and natural gas	$ 1,385	$ 5,294	$ 28,869	$ 61,237	**$ 66,446**
Other	690	2,008	1,252	5,567	**6,654**
Gain on disposition of properties, equipment and other assets	—	5,102	538	136	**3**
Total revenues	2,075	12,404	30,659	66,940	**73,103**
Costs and expenses:					
Oil and natural gas production	786	2,375	9,484	23,914	**29,223**
Depreciation, depletion and amortization	465	1,446	4,949	14,244	**18,558**
General and administrative	1,231	1,934	2,003	4,806	**10,968**
Interest expense	104	17	1,369	3,133	**3,408**
Impairment of oil and natural gas properties	—	—	—	49,575	**17,459**
Impairment of marketable securities	—	—	—	—	**1,136**
Uncollectible value of Enron hedges	—	—	—	10,669	**—**
Total costs and expenses	2,586	5,772	17,805	106,341	**80,752**
Income (loss) before income taxes and minority interest	(511)	6,632	12,854	(39,401)	**(7,649)**
Minority interest in limited partnership	—	(7)	—	—	**—**
Income (loss) before income taxes	(511)	6,639	12,854	(39,401)	**(7,649)**
Income tax expense (benefit)	—	2,139	4,400	(54)	**(6,682)**
Income (loss) before extraordinary items	(511)	4,500	8,454	(39,347)	**(967)**
Fee income from early extinguishment of debt, net of tax	—	165	—	—	**—**
Net income (loss)	(511)	4,665	8,454	(39,347)	**(967)**
Dividends on preferred stock	—	—	—	2,653	**5,256**
Earnings (loss) on common stock	$ (511)	$ 4,665	$ 8,454	$ (42,000)	**$ (6,223)**
Basic earnings (loss) per share	$ (.18)	$ .69	$ 1.23	$ (5.96)	**$ (0.88)**
Diluted income (loss) per share	$ (.18)	$ .69	$ 1.18	$ (5.96)	**$ (0.88)**
Weighted average common and common equivalent shares outstanding:					
Basic	2,871	6,698	6,835	7,046	**7,061**
Diluted	2,871	6,714	7,122	7,046	**7,061**
Statement of Cash Flows Data:					
Net cash provided by (used in):					
Operating activities	$ (127)	$ (8,620)	$ 27,297	$ 25,916	**$ 31,660**
Investing activities	(14,060)	(2,862)	(66,519)	(133,771)	**(76,937)**
Financing activities	35,184	(39)	37,450	102,130	**45,928**

	December 31,				
	1998	1999	2000	2001	2002
	(In thousands)				
Balance Sheet Data:					
Current assets	$ 22,157	$ 31,599	$ 20,262	$ 21,121	**$ 26,198**
Total assets	36,888	50,932	102,372	191,056	**241,174**
Current liabilities	648	10,017	8,655	13,322	**33,193**
Long-term debt, less current maturities	—	—	42,488	44,994	**97,943**
Stockholders' equity	36,240	40,880	49,791	120,379	**99,884**
Total liabilities and stockholders' equity	36,888	50,932	102,372	191,056	**241,174**

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

Forward-Looking Statements.

The statements contained in this report regarding our future financial and operating performance and results, business strategy, market prices, future hedging activities, plans and forecasts under "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Business," and other statements that are not historical facts are forward-looking statements, as defined in Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. We have based these forward-looking statements on our current assumptions, exceptions and projections about future events.

We use the words "may," "will," "expect," "anticipate," "estimate," "believe," "continue," "intend," "plan," "budget," or other similar words to identify forward-looking statements. You should read statements that contain these words carefully because they discuss future expectations, contain projections of results of operations or of our financial conditions, and/or state other "forward-looking" information. We do not undertake any obligation to update or revise publicly any forward-looking statements. These statements also involve risks and uncertainties that could cause our actual results to materially differ from our expectations in this report, including, but not limited to:

- estimates of reserves;
- market factors;
- market prices (including regional basis differentials) of oil and natural gas;
- results of future drilling;
- marketing activity;
- future production and costs;
- and other factors discussed in this report and in our other SEC filings.

We believe that it is important to communicate our expectations of future performance to our investors. However, events may occur in the future that we are unable to accurately predict, or over which we have no control. When considering our forward-looking statements, keep in mind the risk factors and other cautionary statements in this annual report.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for oil and natural gas. Declines in oil or natural gas prices may materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower oil or natural gas prices also may reduce the amount of oil or natural gas that we can produce economically. A decline in oil and/or natural gas prices could have a material adverse effect on the estimated value and estimated quantities of our oil and natural gas reserves, our ability to fund our operations and our financial condition, cash flow, results of operations and access to capital. Historically, oil and natural gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile.

Critical Accounting Policies

In response to the SEC's Release No. 33-8040, "Cautionary Advice Regarding Disclosure About Critical Accounting Policies," we have identified the most critical accounting principles that our financial status depends upon. We determined the critical principles by considering accounting policies that involve the most complex or subjective decisions or assessments. We identified our most critical accounting policies to be those related to our proved reserve estimates, derivatives accounting, functional currency assessment, deferred tax asset valuations and our choice of accounting method for oil and natural gas properties.

We prepared our consolidated financial statements for inclusion in this report in accordance with accounting principles that are generally accepted in the United States (GAAP). GAAP represents a comprehensive set of accounting and disclosure rules and requirements, and applying these rules and requirements requires management judgments and estimates including, in certain circumstances, choices between acceptable GAAP alternatives. The following is a discussion of our most critical accounting policies, judgments and uncertainties that are inherent in our application of GAAP.

Proved reserve estimates.

Estimates of our proved reserves included in this report are prepared in accordance with GAAP and SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

Our proved reserve information included in this report is based on estimates prepared by our independent petroleum engineers.

Because these estimates depend on many assumptions, all of which may substantially differ from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate.

You should not assume that the present value of future net cash flows is the current market value of our estimated proved reserves. In accordance with SEC requirements, we based the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Further, a discount rate of 10% may not be an accurate assumption of future interest rates.

Estimates of proved reserves materially impact depletion expense. If the estimates of proved reserves decline, then the rate at which we record depletion expense increases, reducing net income. A decline in the proved reserves estimate may result from lower market prices, and a decline may make it uneconomical to drill or produce from higher cost fields. In addition, the decline in proved reserve estimates may impact the outcome of our assessment of our oil and natural gas properties for impairment.

Accounting for derivatives.

We engage in price risk management activities to protect against commodity price fluctuations and in connection with the incurrence of debt related to our acquisition activities. We have a policy of hedging oil and natural gas prices whenever such prices are in excess of prices anticipated in our operating budget and profit plan through the use of swap agreements. These derivatives are not held for trading purposes.

We formally document all relationships between hedging instruments and hedged items, as well as our risk-management objective and strategy for undertaking various hedge transactions. The process includes linking all derivatives that are designated as cash flow hedges to forecasted transactions. We also formally assess, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. When it is determined that a derivative is not highly effective as a hedge or that it ceased to be a highly effective hedge, we discontinue hedge accounting prospectively.

Effective as of November 30, 2001, we ceased hedge accounting for our hedge transactions then in place due to the bankruptcy filing of the counterparty to our swap agreements (see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk").

Assessments of functional currencies.

We determine the functional currencies of our subsidiaries by assessing the currency of the economic environment in which a subsidiary primarily realizes and expends its operating revenues, costs and expenses. We have determined that the Canadian dollar is the functional currency of our international operations in Canada. Our assessment of functional currencies can have a significant impact on our periodic results of operations and on our financial position.

Deferred tax asset valuations.

We periodically assess the probability of recovering recorded deferred tax assets based on our assessment of future earnings outlooks by tax jurisdiction. These estimates are inherently imprecise because we make many assumptions in the assessment process. For the years ended December 31, 2001 and 2002, our net deferred tax asset in the U.S. of $7.6 million and $3.5 million, respectfully, have been fully reserved as it continues to be uncertain whether we will be able to utilize our net deferred tax asset. We are in a net deferred tax liability position in Canada, and, accordingly, no valuation allowance has been provided. Going forward, we will continue to evaluate the need for a valuation allowance in the U.S. based on various factors, including operating performance, the future outlook of oil and natural gas prices and the nature of the components of the deferred tax asset.

Accounting for oil and natural gas properties.

The accounting for and disclosure of oil and natural gas producing activities requires that we choose between GAAP alternatives and that we make judgments regarding estimates of future uncertainties.

We use the full cost method of accounting, which involves capitalizing all acquisitions, exploration, exploitation and development costs. Once we incur costs, they are recorded in the full cost pool or in unevaluated properties. Unevaluated property costs are not subject to depletion. We review our unevaluated costs on an ongoing basis, and we expect these costs to be evaluated in one to three years and transferred to the full cost pool during that time. The full cost pool is comprised of lease and well equipment and exploration and development costs incurred plus intangible acquired proved leaseholds.

We calculate depletion using the unit-of-production method. Under this method, the sum of the full cost pool and all estimated future development costs are divided by the total amount of proved reserves. This rate is applied to our total production for the period, and the appropriate expense is recorded. We capitalize the portion of general and administrative costs that are attributable to our acquisition, exploration, exploitation and development activities.

To the extent that total capitalized oil and natural gas property costs (net of related deferred income taxes and accumulated depreciation, depletion and amortization) exceed the estimated future net revenues from proved properties using current period-end prices discounted at 10%, adjusted for related income tax effects, plus the lower of cost or fair value of unproved properties, excess costs are charged to operations. Once incurred, a write-down of oil and natural gas properties is not reversible at a later date even if oil or natural gas prices increase. We could be required to write down our oil and natural gas properties if there is a decline in oil or natural gas prices, or downward adjustments are made to our estimates of proved reserves. During 2001 and 2002, we recognized impairment charges of $20.9 million and $17.5 million, respectively, with respect to our properties located in Canada, and in 2001, we recognized an impairment charge of $28.7 million, with respect to our properties located in the United States. These charges were the result of low prices for oil and natural gas at September 30, 2001, December 31, 2001 and June 30, 2002.

Recently Issued Accounting Standards

SFAS No. 141, "Business Combinations", and SFAS No. 142, "Goodwill and Intangible Assets", were issued in June 2001 and became effective for us on July 1, 2001 and January 1, 2002, respectively. When we filed our Annual Report on Form 10-K on March 26, 2003, we did not believe that SFAS No. 141 or SFAS No. 142 applied to oil and natural gas companies as we did not believe the statements changed the authoritative literature specific to oil and natural gas properties which contain specific accounting and disclosure guidance for companies' interests in oil and natural gas properties. As a result, we did not make the disclosures required under SFAS No. 142. In connection with the SEC review process of our proxy materials for the upcoming shareholders meeting, we have determined that these standards require mineral use rights, such as leasehold interests, be separately classified on the balance sheet. Specifically, these standards require that mineral use rights, including intangible acquired proved leaseholds, be classified on the balance sheet as an intangible asset for all leaseholds purchased subsequent to June 30, 2001. Accordingly, we have reclassified on our balance sheets at December 31, 2001 and 2002 mineral use rights, including leasehold interests, acquired subsequent to July 1, 2001 as an intangible asset. We have also determined that lease and well equipment purchased subsequent to June 30, 2001 also be separately classified on the balance sheet. The reclassification of amounts to "intangible acquired proved leaseholds" and "lease and well equipment" from "proved developed oil and natural gas properties" had no effect on depreciation, depletion or amortization for either of the years ended December 31, 2001 or 2002 or on total assets or total accumulated depreciation, depletion and amortization at December 31, 2001 and 2002. We do not believe that our consolidated balance sheets will be comparable to other companies in our industry as we do not believe that other companies in our industry separately classify mineral use rights, including leasehold interests, on their balance sheets as required under SFAS No. 141 and SFAS No. 142.

In June 2001, the Financial Accounting Standards Board issued SFAS No. 143, "Accounting for Asset Retirement Obligations". The statement requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time that the obligations are incurred. Upon initial recognition of a liability, that cost should be capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. We will adopt the new rules on asset retirement obligations on January 1, 2003, for both our U.S. and Canadian properties. Application of the new rules is expected to result in an increase in net proved developed and undeveloped oil and natural gas properties of approximately $11.2 million, recognition of an asset retirement obligation liability of approximately $10.2 million, a reduction in deferred income tax liability of approximately $700,000, and a cumulative effect of adoption that will increase net income and stockholders' equity by approximately $1.7 million.

Our Results of Operations

The following tables present production and average unit prices and costs for the periods and, beginning in 2001, when we first acquired Canadian assets, the relevant geographic segments:

	Year Ended December 31,		
	2000	2001	2002
Production:			
Oil (Mbbls)			
U.S.	433	887	**869**
Canada	—	80	**399**
Total	433	967	**1,268**
Natural gas (Mmcf)			
U.S.	3,982	6,243	**6,878**
Canada	—	2,086	**6,565**
Total	3,982	8,329	**13,443**
Natural gas liquids (Mbbls)			
U.S.	89	96	**74**
Canada	—	68	**242**
Total	89	164	**316**
Mmcfe			
U.S.	7,114	12,141	**12,536**
Canada	—	2,974	**10,411**
Total	7,114	15,115	**22,947**

	Year Ended December 31,		
	2000	2001	2002
Average Sales Price (including hedge settlements):			
Oil (per Bbl)			
U.S. (1)	$ 27.39	$ 24.40	**$ 18.78**
Canada	$ —	$ 21.71	**$ 24.23**
Total (2)	$ 27.39	$ 24.17	**$ 20.50**
Natural gas (per Mcf)			
U.S. (3)	$ 3.72	$ 4.73	**$ 2.43**
Canada	$ —	$ 2.59	**$ 2.75**
Total (4)	$ 3.72	$ 4.20	**$ 2.59**
Natural gas liquids (per Bbl)			
U.S.	$ 24.60	$ 18.96	**$ 16.66**
Canada	$ —	$ 15.92	**$ 18.38**
Total	$ 24.60	$ 17.70	**$ 17.98**
Total oil and natural gas revenues (per Mcfe)			
U.S.	$ 4.06	$ 4.37	**$ 2.73**
Canada	$ —	$ 2.76	**$ 3.09**
Total	$ 4.06	$ 4.05	**$ 2.90**

(1) Reflects the impact on the U.S. average oil price of monthly hedge settlements for the years ended December 31, 2000, 2001 and 2002 of $1.85 decrease, $0.86 increase and $4.97 decrease, respectively.

(2) Reflects the impact on the total average oil price of monthly hedge settlements for the years ended December 31, 2000, 2001 and 2002 of $1.85 decrease, $0.79 increase and $3.40 decrease, respectively.

(3) Reflects the impact on the U.S. average natural gas price of monthly hedge settlements for the years ended December 31, 2000, 2001 and 2002 of $0.09 decrease, $0.87 increase and $0.49 decrease, respectively.

(4) Reflects the impact on the total average natural gas price of monthly hedge settlements for the years ended December 31, 2000, 2001 and 2002 of $0.09 decrease, $0.65 increase and $0.25 decrease, respectively.

	Year Ended December 31,		
	2000	2001	2002
Expenses (per Mcfe):			
Oil and natural gas production			
U.S.	$ 1.05	$ 1.43	**$ 1.20**
Canada	$ —	$ 0.81	**$ 0.94**
Total	$ 1.05	$ 1.32	**$ 1.08**
Production and ad valorem taxes			
U.S.	$ 0.27	$ 0.33	**$ 0.32**
Canada	$ —	$ 0.04	**$ 0.04**
Total	$ 0.27	$ 0.27	**$ 0.19**
General and administrative			
U.S.	$ 0.28	$ 0.34	**$ 0.54**
Canada	$ —	$ 0.23	**$ 0.40**
Total	$ 0.28	$ 0.32	**$ 0.48**
Depreciation, depletion and amortization			
U.S.	$ 0.69	$ 0.80	**$ 0.76**
Canada	$ —	$ 1.50	**$ 0.87**
Total	$ 0.69	$ 0.94	**$ 0.81**

Comparison of Years Ended December 31, 2001 and 2002.

Revenues. Our revenues from the sale of oil, natural gas and NGLs for the year ended December 31, 2002, increased by $5.2 million, or nearly 9%, to $66.4 million from $61.2 million for 2001. This increase in revenues is primarily attributable to increased production resulting from acquisitions made during the years ended 2001 and 2002. Our production of oil, natural gas and NGLs increased by 301,000 Bbls, 5.1 Bcf, and 152,000 Bbls, respectively, for the year ended December 31, 2002, compared to the year ended December 31, 2001. These increases are primarily attributable to our acquisitions of Addison Energy Inc., completed in late April 2001, the PrimeWest properties, completed in December 2001, the Medicine River properties, completed in April 2002, and the DJ Basin properties completed in November 2002. Production from these acquisitions during 2002 was 295,000 Bbls of oil, 3.5 Bcf of natural gas, and 139,000 Bbls of NGLs.

The increase in revenue resulting from increased production was partially offset by lower prices received for oil, natural gas and NGLs. Our average oil, natural gas and NGL prices include the effects of quality, gathering and transportation costs as well as the effect of monthly oil and natural gas hedge settlements. Our average oil price received during the year ended December 31, 2002, was $20.50 per Bbl as compared to $24.17 per Bbl for 2001, which decreased revenue by $3.6 million. Our average natural gas price received during the year ended December 31, 2002, was $2.59 per Mcf as compared to $4.20 per Mcf for 2001, which decreased revenue by $13.4 million. Our average NGL price received during the year ended December 31, 2002, was $17.98 per Bbl as compared to $17.70 per Bbl for 2001, which increased revenue by less than $100,000.

We had two well control events during 2002. The Leon #3 well control event did not involve the release of any oil or natural gas to the surface and, as a result, we did not record any revenue or expenses during the well control event. The Leon #3 well was later completed as a producing natural gas well. During the period of September through December 2002, as a result of normal operations from the Leon #3, we recorded as revenue approximately $364,000 from the sale of approximately 106,000 Mcf of natural gas. Oil and natural gas production costs and production and ad valorem taxes for the Leon #3 during this period were less than $100,000. We were able to sell some natural gas during the second well control event, the Miami Corp. #35. During November and December, 2002, we sold 254,000 Mcf of natural gas from this well which increased revenue by $1.0 million. Oil and natural gas production costs and production and ad valorem taxes for the Miami Corp. #35 during this period were less than $100,000. There has not been any production from this well since December 2002. The well is currently temporarily abandoned and, at this time, we do not know when, or if, we will be able to complete this well and restore it to production.

Our well control insurance policy, which covered both our United States and Canadian operations expired in August 2002, and our insurance carrier declined to renew our policy. We have obtained well control coverage for our Canadian drilling and workover activities effective as of February 12, 2003. As a result of the claims we have made under our well control insurance policy, we have been unable to obtain new well control insurance for our United States operations on terms acceptable to us. We have delayed projects that we believe contain operational risks and we may continue to delay or postpone projects in the United States in the future if we are unable to obtain well control insurance in the United States on acceptable terms. The project delays could reduce our estimated production for 2003. We further expect that if we are able to obtain such insurance for our United States operations, that the rates used to determine the premium will be substantially higher than our prior policy and that we will have to accept a higher level of risk through either higher deductibles or co-insurance clauses than provided in our previous policy.

Our other income for the year ended December 31, 2002, was $6.6 million as compared to $5.7 million for 2001. This income primarily consisted of income from derivative ineffectiveness and terminated hedges, interest income, salt water disposal income and well supervision fees. The increase in other income was primarily attributable to $6.1 million in non-cash income from derivative ineffectiveness and terminated hedges during the year ended December 31, 2002, compared to $4.8 million in non-cash income from derivative ineffectiveness and terminated hedges for 2001.

Costs and Expenses. Our total costs and expenses for the year ended December 31, 2002, decreased by $25.5 million to $80.8 million from $106.3 million for 2001. This decrease was mainly attributable to non-cash ceiling test write-downs of $49.6 million and the write-off of $10.7 million of derivative assets during 2001, compared to a ceiling test write-down of $17.5 million during 2002. The write-off of $10.7 million in 2001 represented 80% of the value of the Enron derivative asset as of November 30, 2001. This decrease was partially offset by increased expenses due to our acquisition of Addison Energy Inc., and our acquisition of the STB Energy, PrimeWest, Medicine River, and DJ Basin properties, and $1.1 million in impairment charges related to the value of marketable securities. We acquired the marketable securities in two companies prior to initiating discussions of potential business combinations with these companies.

Our oil and natural gas production costs for the year ended December 31, 2002, increased $5.0 million, or 25%, to $24.8 million from $19.8 million for 2001. Our acquisition of the PrimeWest, Medicine River and the DJ Basin properties increased oil and natural gas production costs by $4.8 million. Oil and natural gas production costs on a unit of production basis decreased $0.24 per Mcfe to $1.08 per Mcfe for the year ended December 31, 2002, from $1.32 per Mcfe during 2001. The decrease in oil and natural gas production costs was primarily a result of the lower costs, on a unit of production basis, of our Canadian properties. Production and ad valorem taxes for the year ended December 31, 2002, increased by $274,000, or 6.6%, to $4.4 million from $4.1 million for 2001. Production and ad valorem taxes are generally based upon the price received for production and are not affected by monthly oil and natural gas hedge settlements. The increase in production and ad valorem taxes is primarily attributable to higher ad valorem taxes paid in Canada. There are no production taxes paid in Canada.

Our depreciation, depletion and amortization costs for the year ended December 31, 2002, increased by $4.4 million, or 30%, to $18.6 million from $14.2 million for the same period in 2001, as a result of our acquisitions of Addison Energy Inc. and the PrimeWest, Medicine River and the DJ Basin properties. Depletion expense on production from these properties was approximately $5.2 million. This increase was partially offset by lower depletion rates due to non-cash ceiling test write-downs taken in the third and fourth quarters in 2001, and in the second quarter in 2002.

Our general and administrative costs for the year ended December 31, 2002, increased by $6.2 million, or 128%, to nearly $11.0 million from $4.8 million for 2001. The increase in general and administrative costs was primarily attributable to our increased staffing needs as a result of our acquisitions of Addison Energy Inc. and the STB Energy, PrimeWest and Medicine River properties. Additionally, general and administrative costs increased as a result of legal costs incurred in pursuing our bankruptcy claim against Enron North America Corp. ($474,000); stock option compensation expense related to the Addison stock option plan ($1.4 million); and, costs incurred for financial and legal advisors we retained to evaluate the offer made by our chairman to purchase all of the outstanding shares of our stock that he does not already own ($659,000).

Our interest expense for the year ended December 31, 2002, increased to $3.4 million from $3.1 million for 2001. This increase was primarily caused by higher average outstanding borrowings and higher interest rates during the year ended December 31, 2002, when compared to 2001. Our weighted average interest rate for the year ended December 31, 2002, was 4.38% compared to 3.95% for 2001.

Under full cost accounting rules, we must compare the amount in our full cost pools (separate pools exist for the United States and Canada) to a ceiling test limit. In calculating future net revenues for the ceiling test limit, current prices and costs are generally held constant indefinitely. As a result of lower prices for Canadian natural gas at September 30, 2002, we had a pre-tax, non-cash write-down of our oil and natural gas properties of $17.5 million ($9.7 million after-tax) from our Canadian full cost pool. As a result of low oil and natural gas prices at September 30, 2001 and December 31, 2001, we had pre-tax, non-cash ceiling test write-downs of our oil and natural gas properties during the year ended December 31, 2001, of $49.6 million of which $28.7 million was from our United States full cost pool and $20.9 million was from our Canadian full cost pool. Due to the volatility of oil and natural gas prices, it is possible that we will incur additional non-cash ceiling test write-downs in the future.

Periodically, we invest in the marketable securities of other companies prior to initiating discussions of potential business combinations with those companies. At December 31, 2002, the cost of our investments in marketable securities was $2.7 million, which exceeded the market value of these securities on December 31, 2002, by $886,000. We consider these investments to be "available for sale", which means that unrealized gains and losses are excluded from earnings and included in other comprehensive income unless the decline in the fair value of the investment is "other than temporary." During the year ended December 31, 2002, we determined that, due to the significant decline in market value of two of our investments, the decline in the fair value of two of our investments in marketable securities was "other than temporary" and, as a result, we have recognized a non-cash pre-tax impairment expense of $1.1 million. At December 31, 2002, we have a net unrealized gain on marketable securities of $258,000 remaining in other comprehensive income. At the present time, we no longer intend to pursue a business combination with either of these two companies.

We have recorded a current income tax benefit of $2.7 million in the United States for the year ended December 31, 2002, to reflect a refund of taxes expensed and paid during 2001 and the expected refund of income taxes carried back to prior years for 2001 and 2002 taxable losses, after deducting intangible drilling costs. For the year ended December 31, 2002, we have not recorded any deferred income tax benefits or expense in the U.S., as it continues to be uncertain whether we will be able to utilize our net deferred tax asset. Accordingly, the tax effects of our U.S. generated income was offset by a reduction in our valuation allowance. Because of the deferred tax asset and resulting valuation allowance in the U.S., management expects tax expense on U.S. operations to be reduced in the near future. In Canada we have recorded a deferred tax benefit of $4.0 million. The deferred tax benefit is primarily the result of the non-cash ceiling test write-down on our Canadian full cost pool. We did not have any current income tax expense or benefit in Canada during 2002. We expect to continue to provide for taxes in Canada based upon the level of our Canadian income.

Comparison of Years Ended December 31, 2000 and 2001.

Revenues. Our revenues from the sale of oil, natural gas and NGLs for the year ended December 31, 2001, increased by $32.3 million, or 112%, to $61.2 million from $28.9 million for 2000. This increase resulted primarily from production increases of approximately 97,900 Bbls of oil, 2.7 Bcf of natural gas and 68,300 Bbls of NGLs from our acquisition of the STB Energy properties, completed in March 2001, and Addison, completed in April 2001. Additionally, our acquisition of the Central Resources properties, completed in September 2000, was included for the full year in 2001, as compared to four months during 2000.

The increase in revenues was also attributable to higher natural gas prices that were partially offset by lower oil and NGL prices. Our average oil, natural gas and NGL prices include the effects of quality, gathering and transportation costs as well as the effect of monthly oil and natural gas hedge settlements. Our average oil price received during 2001 was $24.17 per Bbl as compared to $27.39 per Bbl for 2000, which decreased revenue by $1.3 million. Our average natural gas price received during 2001 was $4.20 per Mcf as compared to $3.72 per Mcf for 2000, which increased revenue by $2.1 million. Our average NGLs price received during 2001 was $17.70 per Bbl as compared to $24.60 per Bbl for 2000, which decreased revenue by $615,000.

Our other income for 2001 was $5.7 million as compared to $1.8 million for 2000. This income primarily consisted of income from derivative ineffectiveness, income from hedges terminated prior to their expiration, interest income, salt water disposal income and well supervision fees. The increase in other income was primarily attributable to $3.5 million from the ineffectiveness of derivative contracts and $1.3 million in income from hedges that we terminated prior to their expiration. See "Item 7A. Quantitative and Qualitative Disclosure About Market Risk" for a discussion of the accounting for terminated hedges in future periods.

Costs and Expenses. Our total costs and expenses for 2001 increased by $88.5 million to $106.3 million from $17.8 million for 2000. This increase was mainly attributable to (1) our acquisitions of the Central Resources properties, the STB Energy properties and Addison, (2) the non-cash ceiling test limitation write-downs of $49.6 million, and (3) the write-off of $10.7 million, which represents 80% of the value, as of November 30, 2001, of the Enron derivative assets.

Our oil and natural gas production costs for 2001 increased by $12.4 million, or 165%, to $19.9 million from $7.5 million for 2000. Our acquisitions of the STB Energy properties and Addison increased oil and natural gas production costs by $3.3 million. Production and ad valorem taxes for 2001 increased by $2.1 million, or 105%, to $4.1 million from $2.0 million last year. Additionally, oil and natural gas production costs and production and ad valorem taxes related to our acquisition of the Central Resources properties were included for the full year, as compared to four months during 2000.

Our depreciation, depletion and amortization costs for 2001 increased by $9.3 million, or 190%, to $14.2 million from $4.9 million for 2000. Our acquisitions of the STB Energy properties and Addison increased depreciation, depletion and amortization costs by $5.0 million. Additionally, depreciation, depletion and amortization costs related to our acquisition of the Central Resources properties were included for the full year, as compared to four months during 2000.

Our general and administrative costs for 2001 increased by $2.8 million, or 140%, to $4.8 million from $2.0 million for 2000. The increase in general and administrative costs was primarily attributable to our increased staffing needs as a result of our acquisitions of the Central Resources properties, the STB Energy properties and Addison.

Our interest expense for 2001 increased to $3.1 million from $1.4 million for 2000. This increase was primarily attributable to relatively high debt levels following the acquisitions of the STB Energy properties and Addison during the first half of 2001. These borrowings were repaid in June from the proceeds of the 5% convertible preferred stock offering.

We acquired Addison in April 2001, and we also completed significant property acquisitions during the second half of 2000 and during 2001. Oil and natural gas prices trended higher throughout 2000, and were at historically high levels at December 31, 2000. During 2001, oil and natural gas prices decreased throughout most of the year. We evaluate acquisitions utilizing our best estimate of product prices and the amount of capital expenditures and operating expense to be incurred over the life of the reserves. Under full cost accounting rules, we must compare the amount in our full cost pools (separate pools exist for the United States and Canada) to a ceiling test limit. The ceiling test limit is calculated using product prices as of the last day of the fiscal quarter. Capital expenditures and operating expenses are calculated without any escalation for inflation. As a result of lower oil and natural gas prices at the end of both the third and fourth quarters of 2001, we had non-cash write-downs of our oil and natural gas properties of $49.6 million, of which $28.7 million was from our United States full cost pool and $20.9 million was from our Canadian full cost pool. At December 31, 2001, we used a realized oil price of $17.76 per Bbl, natural gas price of $2.23 per Mcf, and an NGLs price of $15.09 per Bbl, as the basis for determining the value of our reserves. We did not use our hedge contracts in determining reserve values.

In connection with the incurrence of debt related to our acquisition activities and to protect against commodity price fluctuations, our management adopted a policy of hedging oil and natural gas prices through the use of commodity futures, options and swap agreements. During 2000 and through the third quarter of 2001, we entered into several hedging contracts with Enron North America. As a result of the failure of Enron North America to make payments due us in December 2001, we terminated all of our hedging contracts with Enron North America. Prior to this termination, Enron North America and its parent, Enron Corp., filed for bankruptcy under Chapter 11 of the United States Code. We believe, based upon oil and natural gas prices on the date of termination, that we were owed approximately $15.3 million, including settlements already due, but the exact amount will be determined pursuant to the terms of the ISDA Master Agreement. As of November 30, 2001, we had recorded a $13.2 million derivative asset for oil and natural gas hedge derivatives from Enron North America. This amount, calculated in accordance with SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities", represents the estimated value of future monthly settlements to be received from the derivatives contracts. As a result of our termination of the derivatives contracts and the bankruptcy of the counterparty, we must record the derivative asset related to the oil and natural gas hedge derivatives from Enron North America at their estimated fair value. There currently exists an informal market for Enron North America's bankruptcy claims. Based upon informal offers that we have received from third parties attempting to purchase these claims, management currently believes the fair value of the derivative asset was approximately $2.8 million. As a result, we have written off to expense $10.7 million of the derivative asset for oil and natural gas hedge derivatives from Enron North America.

Our effective tax rate in 2000 was 34%. In 2001, the effective rate was less than 1% due to the ceiling test write-downs and write-off of the Enron derivative asset. We could not utilize our net loss in the U.S. because it is uncertain whether we will be able to realize the deferred tax asset resulting from the ceiling test write-downs and the write-off of the Enron derivative asset

Net Income (Loss). We had a net loss for 2001 of $39.3 million representing $5.96 per basic share. During 2000, we had a net income of $8.5 million representing $1.23 per basic share and $1.18 per diluted share.

Our Liquidity, Capital Resources and Capital Commitments

General.

Most of our growth has resulted from recent acquisitions and our development and exploitation program. Consistent with our strategy of acquiring and developing reserves, we have an objective of maintaining financing flexibility. In the past, we have utilized a variety of sources of capital to fund our acquisition, development and exploitation programs and to fund our operations. Our general financial strategy is to use a combination of cash flow from operations, bank financing and the sale or issuance of equity securities to fund our operations, conduct development and exploitation activities, and to fund acquisitions. We do not have a set budget for acquisitions as these tend to be opportunity driven. Historically, we have used the proceeds from the issuance of equity securities and borrowings under our credit agreements to raise cash to fund acquisitions. We cannot assure you that funds will be available to us in the future to meet our budgeted capital spending or to fund acquisitions. Furthermore, our ability to borrow from sources other than our credit agreements is subject to restrictions imposed by our lenders. If we cannot secure additional funds for our planned development and exploitation activities or for future acquisitions, then we will be required to delay or substantially reduce these activities.

During the year ended December 31, 2002, we increased our long-term debt by 118% to approximately $97.9 million at December 31, 2002. We generated cash flow from operations before changes in working capital during the year ended December 31, 2002 of approximately $26.3 million and approximately $31.7 million after changes in working capital, which helped fund our acquisition, development and exploitation activities. At December 31, 2002, our cash and cash equivalents balances increased by less than 5% from December 31, 2001. Working capital at December 31, 2002, decreased significantly from December 31, 2001, primarily because of changes in the value of our outstanding hedge positions. Because product prices at December 31, 2002, were higher than at December 31, 2001, the value of our hedges have changed from a net asset to a net liability. We have also entered into new hedge contracts during 2002, for additional volumes to be delivered during 2003 and 2004, that also increased our net oil and natural gas hedge derivative liabilities.

Prices for oil and natural gas have been volatile since December 31, 2002. The following table reflects the NYMEX closing price for the month indicated:

Month	Oil	Natural Gas
December 2002	$31.20	$4.79
January 2003	$32.70	$5.03
February 2003	$35.73	$5.50
March 2003	n/a(1)	$9.28

(1) The March 2003 oil contract has not yet closed. The average price for the month through March 25, 2003, was $33.89.

As a result of this volatility in prices, we have made cash payments of approximately $1.3 million for oil hedge settlements for January and February 2003 and approximately $6.0 million for natural gas hedge settlements for January, February and March 2003. These payments should be completely or partially offset by higher prices realized on the sale of oil and natural gas production. Additionally, the unrealized loss in the market value of our hedges as of February 28, 2003, based on quotes from our counterparties, has increased to approximately $27.6 million.

Acquisitions and Capital Expenditures.

During the year ended December 31, 2002, we spent approximately $55.8 million on oil and natural gas property acquisitions. On April 29, 2002, Addison, our Canadian subsidiary, purchased oil and natural gas assets for approximately $25.8 million or CDN $40.5 million ($24.7 million or CDN $36.3 million after contractual adjustments). The transaction was funded with borrowings under our U.S. and Canadian credit agreements. On November 1, 2002, we purchased oil and natural gas properties located in the DJ Basin in Colorado for approximately $22.0 million ($21.1 million after contractual adjustments). The transaction was funded with $19.7 million of bank debt from our U.S. credit agreement and $1.4 million from surplus cash.

We have planned development and exploitation activities for our major operating areas. We have budgeted up to $34.7 million for our development and exploitation activities in 2003, of which $12.3 million is for the United States and $22.4 million is for Canada. None of these planned capital expenditures are contractually required. In addition, we are continuing to evaluate oil and natural gas properties for future acquisitions. A variety of factors will determine the amount we ultimately spend during 2003 on acquisitions, development and exploitation activities, including prevailing prices for oil and natural gas, our expectations as to future pricing, the level of cash flow from operations, and the availability of additional debt and/or equity capital. If oil and natural gas prices drop significantly for an extended period of time, we may reduce our anticipated capital expenditure budget for 2003. We strive to maintain our indebtedness at moderate levels in order to provide sufficient financial flexibility to take advantage of future acquisition opportunities.

See "Item 1.—Business—Investment Considerations and Risk Factors—We are exposed to operating hazards and uninsured risks" for a discussion of our inability to obtain well control insurance for our United States operations under terms we consider to be economical and the impact that this has had and may continue to have on our development and exploitation activities. We currently plan on spending the $12.3 million that has been budgeted for development and exploitation activities in the United States even if we do not obtain any well control insurance for our United States operations.

We expect to continue to utilize cash from operations, proceeds from the sale of oil and natural gas properties and funds available under our credit agreements to fund our acquisitions, capital expenditures and working capital during 2003. We believe that our capital resources from existing cash balances, cash flow from operating activities, and borrowing capacity under our credit agreements are adequate to meet the cash requirements of our business. However, future cash flows are subject to a number of variables, including production volumes, oil and natural gas prices and interest rates. If cash flows decline we would be required to reduce our capital expenditure budget, which in turn may affect our production in future periods. We cannot assure you that operations and other capital resources will provide cash in sufficient amounts to maintain or initiate planned levels of capital expenditures.

Credit Agreements.

U.S. Credit Agreement. Our restated U.S. credit agreement provides for borrowings of up to $124.0 million under a revolving credit facility with a borrowing base of $82.0 million. Our borrowing base is determined based on a number of factors including commodity prices, however, we use hedges to lessen the impact of volatility in commodity prices. The borrowing base will be redetermined as of May 1, 2003, and each November 1 and May 1 thereafter. At December 31, 2002, we had approximately $34.4 million of outstanding indebtedness, letter of credit commitments of $310,000 and approximately $47.3 million available for borrowing under our U.S. credit agreement. At February 28, 2003, we had $37.5 million of outstanding indebtedness, letter of credit commitments of $310,000 and approximately $44.2 million available for borrowing. The U.S. credit agreement contains financial covenants and other restrictions that require us to maintain a minimum consolidated tangible net worth as well as financial ratios. As of December 31, 2002, we were in compliance with the covenants contained in the U.S. credit agreement. Borrowings under the credit agreement are secured by a first lien mortgage providing a security interest in 90% of our U.S. oil and natural gas properties. At our election, interest on borrowings may be (i) the greater of the administrative agent's prime rate or the federal funds effective rate plus an applicable margin or (ii) LIBOR (London InterBank Offered Rate) plus an applicable margin. At December 31, 2002, the six month LIBOR rate was 1.38%, which would result in an interest rate of approximately 2.63% on any new indebtedness we may incur under the U.S. credit agreement. At February 28, 2003, our weighted average cost of outstanding U.S. indebtedness was 2.64%.

In connection with the merger, we have received a commitment letter from our lead bank to amend our U.S. credit agreement that will increase our U.S. borrowing base to $100 million. The U.S. borrowing base will be reduced to $92.5 million 90 days after the effective time of the merger, and will be further reduced by $7.5 million every 90 days thereafter until the next scheduled borrowing base redetermination. The amendment will also provide for an extension of the U.S. credit agreement maturity date. The new maturity date will be the third anniversary of the effective time of the merger. The commitment is subject to certain closing conditions outlined in the commitment letter.

Canadian Credit Agreement. Our restated Canadian credit agreement provides for borrowings of up to U.S. $157.5 million under a revolving credit facility with a borrowing base of U.S. $83.0 million. Our borrowing base is determined based on a number of factors including commodity prices, however, we use hedges to lessen the impact of volatility in commodity prices. The borrowing base will be redetermined as of May 1, 2003, and each November 1 and May 1 thereafter. At December 31, 2002, we had approximately U.S. $63.5 million of outstanding indebtedness and approximately U.S. $19.5 million available for borrowing under our Canadian credit agreement. At February 28, 2003, we had approximately U.S. $76.0 million of outstanding indebtedness and approximately U.S. $7.0 million available for borrowing. The Canadian credit agreement contains financial covenants and other restrictions that require us to maintain a minimum consolidated tangible net worth as well as financial ratios. As of December 31, 2002, we were in compliance with the covenants contained in the Canadian credit agreement. Borrowings under the credit agreement are secured by a first lien mortgage providing a security interest in 90% of our Canadian oil and natural gas properties. At our election, interest on borrowings may be (i) the Canadian prime rate plus an applicable margin or (ii) the Banker's Acceptance rate plus an applicable margin. At December 31, 2002, the six month Banker's Acceptance rate was 2.88%, which would result in an interest rate of approximately 4.38% on any new indebtedness we incur under the Canadian credit agreement. At February 28, 2003, our weighted average cost of outstanding Canadian indebtedness was 4.44%.

In connection with the merger, we have received a commitment letter from our lead bank to amend our Canadian credit agreement that will increase our Canadian borrowing base to $100 million. The Canadian borrowing base will be reduced to $92.5 million 90 days after the effective time of the merger, and will be further reduced by $7.5 million every 90 days thereafter until the next scheduled borrowing base redetermination. The amendment will also provide for an extension of the Canadian credit agreement maturity date. The new maturity date will be the third anniversary of the effective time of the merger. The commitment is subject to certain closing conditions outlined in the commitment letter.

Dividend restrictions. We have not paid any cash dividends on our common stock, and we do not anticipate paying cash dividends on our common stock in the foreseeable future. In addition, our credit agreements currently prohibit us from paying dividends on our common stock. If there were a default under our credit agreements, we will not be able to pay dividends on the shares of our 5% convertible preferred stock. Even if our credit agreements permitted us to pay cash dividends, we can make those payments only from our surplus which equals the excess of the fair value of our total assets over the sum of our liabilities plus our total paid-in share capital. In addition, we can pay cash dividends only if after paying those dividends we were able to satisfy our liabilities as they become due. We cannot assure you that we will have any surplus.

Financial covenants and ratios. The U.S. and the Canadian credit agreements contain financial covenants and other restrictions that require that we:

- maintain a ratio of our consolidated current assets to consolidated current liabilities (as defined under our credit agreements) of at least 1.0 to 1.0 at the end of any fiscal quarter;
- maintain a minimum consolidated tangible net worth of not less than $48.0 million (adjusted upward by 50% of quarterly net income and 75% of the net proceeds from the issuance of any equity securities after April 26, 2001):
- not permit the ratio of consolidated debt to consolidated total capital to be greater than 65% at the end of each fiscal quarter; and
- not permit the ratio of indebtedness to earnings before interest expense, state and federal taxes, and depreciation, depletion and amortization expense to be more than 3.0 to 1.0 at the end of each fiscal quarter.

We were in compliance with financial covenants and other restrictions under our U.S. and Canadian credit agreements at December 31, 2002.

Effects of the 5% Convertible Preferred Stock Offering.

On June 29, 2001, we sold 5,004,869 shares of 5% convertible preferred stock. We raised approximately $105.1 million in gross proceeds (approximately $101.2 million in net proceeds after fees and commissions). We applied approximately $97.6 million of the offering proceeds to pay-off our bank loans that were incurred for the acquisition of producing oil and natural gas properties and for the acquisition of Addison, and have used the remaining proceeds for general corporate purposes.

Dividends on our preferred stock, are payable quarterly beginning September 30, 2001, and are payable only in cash. Currently, the requirement for such dividend payments is approximately $1.3 million per quarter. The board declared and we paid preferred stock dividends of $2.7 million during 2001 and $5.3 million during 2002. Each share of our 5% convertible preferred stock is convertible into one share of our common stock on or before June 30, 2003. Each share of 5% convertible preferred stock that has not been converted into our common stock by June 30, 2003, will be automatically converted into one share of our common stock on that date.

Common Stock.

In conjunction with our purchase of Addison, the Addison managers agreed to purchase shares of our common stock with a portion of the proceeds they received from the sale of their common shares of Addison to us in April 2001. They purchased 24,940 shares in the open market worth $455,144. In addition, as part of the Addison purchase, the Addison managers purchased 49,880 shares for $910,310 directly from us. The resale of these shares is subject to restriction.

As an incentive to the management and certain key employees of Addison, the board of directors of Addison established the Addison Energy Inc. Stock Option Plan effective June 30, 2002. Addison stock options were issued as of June 30, 2002, under the plan that, if fully exercised, would allow the participants to own in the aggregate 1,000 shares of Addison common stock, approximately 10% of the shares of common stock in Addison on a fully-diluted basis. The Addison stock options are exercisable for a term of five years from the date of the grant. The Addison stock options are subject to vesting. The vesting schedule is as follows:

Vesting Date	Cumulative Percent Vested
Prior to April 26, 2003	None
April 26, 2003	50%
April 26, 2004	75%
April 26, 2005	100%

The exercise price under the Addison stock option plan as of June 30, 2002 was CDN $1,031.61 per share. The price was determined by using a formula as set forth in the Addison stock option agreement. The formula is based upon:

- The value of Addison's proved reserves;
- The amount of any working capital surplus or deficiency;
- Any capital contributions or distributions made after June 30, 2002;
- Any debt owed to us, owed under the Canadian credit agreement or owed to other third parties;
- The total exercise price of all outstanding Addison stock options under the plan;
- The amount of deferred income tax liability incurred after June 30, 2002;
- A calculated amount to allocate certain general and administrative costs that we incur that also benefit Addison; and
- The ratio of the average trading price of our common stock divided by $18.25.

This formula is to be calculated as of December 31 of each year, beginning December 31, 2002, to determine the value of each share of Addison's common stock.

If an Addison stock option is exercised, we are obligated to purchase the shares of Addison common stock from the employee six months later at the then-current price as calculated using the above formula. Each employee receiving an Addison stock option has entered into an agreement that restricts their ability to sell or transfer any Addison common stock acquired under the Addison stock option plan to any party other than to us.

The Addison stock options will become fully vested and exercisable if any of the following occurs:

- A person, or a group of people acting together, has the right to cast more than 50% of the votes when electing our directors;
- Our shareholders approve a merger or other transaction that would result in our shareholders owning less than 50% of the combined entity; or
- We sell the shares of Addison or substantially all of its assets.

At the time one of these events occurs, we are to perform the above calculation to determine the value of each share of Addison common stock as of the date of the event. We will then pay in cash the difference between the calculated value per share and the Addison stock option exercise price times the number of shares of Addison common stock that the participant has the right to purchase under the Addison stock option plan.

The value of a share of Addison common stock was calculated to be CDN $7,013.94 per share as of December 31, 2002.

During 2002, employees exercised stock options on a total of 90,366 shares of our common stock resulting in proceeds to us of approximately $1.0 million.

On September 12, 2001, we announced that our board of directors authorized the purchase of a combined total of 1.5 million shares of our common stock and/or 5% convertible preferred stock. During 2001, we purchased 56,000 shares of our common stock at a cost of $761,000. During 2002, we purchased 188,500 shares of our common stock at a cost of $2.8 million. We have suspended the purchase of shares under this buyback program pending the outcome of our Chairman's announced proposal to acquire all of the outstanding shares of our common and 5% convertible preferred stock that he does not already own. Also during 2002, we reissued 7,512 shares of our common stock to our directors as part of our board of directors compensation plan. The value of the reissued shares was $106,000.

On September 11, 1998 and November 29, 1999, we loaned Douglas H. Miller, our Chairman and Chief Executive Officer, a total of $915,625 to enable him to exercise stock options granted to him under our 1998 stock option plan. Of the outstanding loan balance, $465,625 plus accrued interest was due and payable on November 29, 2002, and $450,000 plus accrued interest was due and payable on September 15, 2004. Mr. Miller paid us all outstanding amounts owed under these loans on November 29, 2002. Under the terms of the Sarbanes-Oxley Act of 2002, we can no longer loan money to our executive officers or amend the terms of any agreements that were in place at the time the law was enacted.

We have not paid any dividends on our common stock and we do not anticipate paying any cash dividends on our common stock in the foreseeable future.

Hedging Transactions.

Our production is generally sold at prevailing market prices. However, we periodically enter into hedging transactions for a portion of our production when market conditions are deemed favorable and oil and natural gas prices exceed our minimum internal price targets. See the discussions in "Item 7A—Quantitative and Qualitative Disclosures About Market Risk."

Our objective in entering into hedging transactions is to manage price fluctuations and achieve a more predictable cash flow associated with our acquisition activities and borrowings under our credit agreements. These transactions limit exposure to declines in prices, but also limit the benefits we would realize if prices increase. As of December 31, 2002, we had entered into the following contracts to hedge our natural gas and oil production under the following terms:

- 776,000-875,000 Mmbtus of natural gas per month from January 1, 2003 through December 31, 2003;
- 62,600 Bbls of oil per month from January 1, 2003 through December 31, 2003; and
- 20,000 Bbls of oil per month from January 1, 2004 through December 31, 2004.

In January and February 2003, we entered into additional contracts to hedge our natural gas and oil production under the following terms:

- 468,300-513,300 Mmbtus of natural gas per month from January 1, 2004 through December 31, 2004; and
- 40,333-47,334 Bbls of oil per month from January 1, 2004 through December 31, 2004.

We may use derivative instruments to manage exposure to commodity prices, foreign currency and interest rate risks. Our objectives for holding derivatives are to minimize risks using the most effective methods to eliminate or reduce the impacts of these exposures.

We occasionally enter into commodity price swap derivatives to manage price risk for a portion of our oil and natural gas production. Commodity price swap derivative contracts are designated as cash flow hedges. As a cash flow hedge, the effective portions of changes in the fair value of the derivative are recorded in other comprehensive income and are recognized in the statement of income when the associated production occurs and the resulting cash flows are reported as cash flows from operations. Ineffective portions of changes in the fair value of cash flow hedges are recognized in earnings. To qualify as a cash flow hedge, these swap contracts must be designated as cash flow hedges and changes in their fair value must correlate with changes in the price expected to be received on future production so that our exposure to the effects of commodity price changes is reduced.

Contractual Obligations and Commercial Commitments.

The following table presents a summary of our contractual obligations at December 31, 2002, with set and determinable payments:

	Payments Due by Period				
Contractual Obligations	**1 Year or Less**	**2-3 Years**	**4-5 Years**	**After 5 Years**	**Total**
			(In thousands)		
Long-term debt	$ —	$ 97,943	$ —	$ —	$ 97,943
Operating leases	868	1,365	576	—	2,809
Drilling/work commitments	1,289	—	—	—	1,289
Preferred stock dividends	2,620	—	—	—	2,620
Total contractual cash obligations	**$ 4,777**	**$ 99,308**	**$ 576**	**$ —**	**$ 104,661**

We also have $310,000 in letters of credit that have been issued to various state regulatory agencies and all of which expire in 2003. See "Item 7A.—Quantitative and Qualitative Disclosures About Market Risk," for discussion of our derivative positions.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Some of the information below contains forward-looking statements. The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices, and interest rates charged on borrowings and earned on cash equivalent investments. The disclosure is not meant to be a precise indicator of expected future losses, but rather an indicator of reasonably possible losses. This forward-looking information provides an indicator of how we view and manage our ongoing market risk exposures. Our market risk sensitive instruments were entered into for hedging purposes, not for trading purposes.

Commodity Price Risk.

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices for natural gas. Pricing for oil and natural gas production is volatile.

In connection with the incurrence of debt related to our acquisition activities and to protect against commodity price fluctuations to achieve a more predictable cash flow, management has adopted a policy of hedging oil and natural gas prices through the use of commodity futures, options and swap agreements. Effective January 1, 2001, we adopted SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activity," which established accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results from the hedged item on the income statement. Companies must formally document, designate and assess the effectiveness of transactions that receive hedge accounting. To date, we have only used cash flow hedges related to our anticipated production. For derivatives classified as cash flow hedges, changes in fair value are recognized in other comprehensive income until the hedged item is recognized in earnings. The ineffective portion of any change in the fair value of a derivative designated as a hedge is immediately recognized in earnings. Hedge effectiveness is measured quarterly based on the relative fair value between the derivative contract and the hedged item over time. At adoption, we recognized a net derivative liability and a reduction in other comprehensive income of approximately $1.1 million as a cumulative effect of the accounting change for all cash flow hedges. Oil and natural gas revenues include the following from the settlement of cash flow hedges: net losses of $1.1 million for the year ended December 31, 2000; net gains of $6.3 million for the year ended December 31, 2001; and net losses of $7.7 million for the year ended December 31, 2002. During the years ended December 31, 2001 and 2002, we recognized a gain of $3.5 million and a loss of $886,000, respectively, in other income for hedging ineffectiveness.

The following table sets forth our oil and natural gas hedging activities as of February 28, 2003. Our contracts are swap agreements for the sale of oil or natural gas based on NYMEX pricing.

Oil Swaps			Natural Gas Swaps		
2003 Contract Period	**Volumes (Bbls)**	**Weighted Average Strike Price**	**2003 Contract Period**	**Volumes (Mmbtus)**	**Weighted Average Strike Price**
First Quarter	187,800	$ 24.03 per Bbl	First Quarter	2,625,000	$ 4.31 per Mmbtu
Second Quarter . . .	187,800	$ 24.03 per Bbl	Second Quarter . . .	2,529,000	$ 3.92 per Mmbtu
Third Quarter	187,800	$ 24.03 per Bbl	Third Quarter	2,406,000	$ 3.85 per Mmbtu
Fourth Quarter . . .	187,800	$ 24.03 per Bbl	Fourth Quarter . . .	2,328,000	$ 3.88 per Mmbtu
2004 Contract Period	**Volumes (Bbls)**	**Weighted Average Strike Price**	**2004 Contract Period**	**Volumes (Mmbtus)**	**Weighted Average Strike Price**
First Quarter	202,000	$ 25.26 per Bbl	First Quarter	1,539,900	$ 4.91 per Mmbtu
Second Quarter . . .	193,750	$ 24.62 per Bbl	Second Quarter . . .	1,490,100	$ 4.22 per Mmbtu
Third Quarter	187,000	$ 24.18 per Bbl	Third Quarter	1,445,100	$ 4.13 per Mmbtu
Fourth Quarter . . .	181,000	$ 23.93 per Bbl	Fourth Quarter . . .	1,404,900	$ 4.30 per Mmbtu

In accordance with management's policy of hedging oil and natural gas prices, we entered into several swap transactions during 2000 and through September 2001. The counterparty of all of these swap transactions was Enron North America Corp., an affiliate of Enron Corp. (the Enron Hedges). On December 2, 2001, Enron Corp. and other Enron related entities, including Enron North America, filed for bankruptcy under Chapter 11 of the United States Code in the United States Bankruptcy Court in the Southern District of New York. We terminated all of our hedging contracts with Enron North America, effective as of December 5, 2001, as a result of the failure of the Enron affiliate to make payments totaling approximately $2.1 million due to us on December 5, 2001, on hedged natural gas volumes and on December 7, 2001, on hedged oil volumes. Based upon oil and natural gas futures prices on December 5, 2001, we believe that we are owed approximately $15.3 million, including settlements already due, but the exact amount will be determined pursuant to the terms of the ISDA Master Agreement.

In accordance with the provisions of SFAS No. 133, we had recorded, as of November 30, 2001, a $13.2 million derivative asset on our balance sheet. This amount represented the estimated fair value of the future cash flows to us based upon the market price of oil and natural gas at that date. Due to the complex nature of the Enron bankruptcy proceedings and the extensive litigation involving Enron, we do not expect that we will receive any settlement as a result of the bankruptcies for an extended period of time; therefore, at December 31, 2001 and 2002, we have classified the Enron derivative asset as an other long-term asset and reduced the asset balance to approximately $2.8 million, which represents our estimate of the fair market value of our bankruptcy claim against Enron North America. Our estimate of the value of our bankruptcy claim is based upon informal offers that we have received from third parties attempting to purchase such claims as well as management's best estimate of the financial condition of Enron's bankruptcy estate as determined from published reports and court filings related to the bankruptcy. As a result, we charged $10.7 million to expense during 2001.

As stated above, we terminated the Enron Hedges effective as of December 5, 2001. Under the requirements of SFAS No. 133, we are required to reclassify amounts related to the Enron Hedges that remain in other comprehensive income as of the date of the termination into revenue as the oil and natural gas volumes that were hedged are produced. During the years ended December 31, 2001 and 2002, we reclassified approximately $1.3 million and $7.0 million, respectively, related to the Enron Hedges from other comprehensive income to other income. At December 31, 2002, approximately $2.1 million remained in other comprehensive income related to the Enron Hedges and will be reclassified into revenue as other income as shown in the following table:

	Amount (In thousands)
During 2003:	
Quarter ending March 31, 2003	$ 976
Quarter ending June 30, 2003	631
Quarter ending September 30, 2003	464
Total amount in 2003	**$ 2,071**

The following table sets forth our oil and natural gas hedges as of December 31, 2002. Our contracts are swap arrangements for the sale of oil and natural gas based upon NYMEX pricing. The market values at December 31, 2002, are estimated and are based on quotes from the counterparties and represent the amount that we would expect to receive or pay to terminate the contracts at December 31, 2002.

Commodity	Contract Date (1)	Effective Date	Termination Date	Notional Volume/ Range Per Month (2)(3)	Aggregate Volume (2)(3)	Strike Price	Market Value at December 31, 2002 (4)
Natural Gas	3/12/2002	1/1/2003	12/31/2003	455,000 Mmbtus	5,460,000 Mmbtus	$ 3.50	$ (5,858,928)
Natural Gas	12/16/2002	1/1/2003	12/31/2003	321,000 Mmbtus - 420,000 Mmbtus	4,428,000 Mmbtus	$ 4.61(5)	$ 90,258
Oil	4/5/2002	1/1/2003	12/31/2003	40,000 Bbls	480,000 Bbls	$ 22.94	$ (1,893,760)
Oil	9/5/2002	1/1/2003	12/31/2003	22,600 Bbls	271,200 Bbls	$ 25.95	$ (261,730)
Oil	9/5/2002	1/1/2004	12/31/2004	20,000 Bbls	240,000 Bbls	$ 23.96	$ 140,001

(1) The counterparties to these contracts are BNP Paribas and Bank One, financial lending institutions and members of our U.S. and Canadian bank groups.

(2) Bbls—Barrels.

(3) Mmbtus—Million British thermal units.

(4) On December 31, 2002, the average forward NYMEX oil prices for calendar 2003 and 2004, were $26.91 per Bbl and $23.36 per Bbl, respectively, and the average forward NYMEX natural gas price for calendar 2003 was $4.58 per Mmbtu.

(5) Weighted average.

A summary of the changes in the fair value of our hedging transactions during 2001 and 2002 follows (in thousands):

Fair value of contracts outstanding as of December 31, 2000	$ (1,068)
Contracts realized or otherwise settled during the year	(10,687)
Change in fair value of terminated Enron hedges	(13,192)
Change in fair values of outstanding hedge positions	25,643
Fair value of contracts outstanding as of December 31, 2001	696
Contracts realized or otherwise settled during the year	8,197
Change in fair value of outstanding hedge positions	(16,677)
Fair value of contracts outstanding as of December 31, 2002	**$ (7,784)**

At December 31, 2002, there was a net loss of approximately $7.1 million in other comprehensive income related to our oil and natural gas hedges. Based upon contractual volumes and current commodity prices we expect to reclassify $7.2 million as a reduction of oil and natural gas revenues during 2003.

Oil and natural gas revenues for the years ended December 31, 2000, 2001 and 2002, include a net loss of $1.1 million, a net gain of $6.3 million, and a net loss of $7.7 million, respectively, from the settlement of cash flow hedges.

Realized gains or losses from the settlement of the swaps are recorded in our financial statements as increases or decreases in oil and natural gas revenues. For example, using the oil swaps in place as of December 31, 2002, if the settlement price exceeded the actual weighted average strike price of $24.03, then a reduction in oil revenues would have been recorded for the difference between the settlement price and $24.03 multiplied by the actual notional volume. Conversely, if the settlement price was less than $24.03, then an increase in oil revenues would have been recorded for the difference between the settlement price and $24.03 multiplied by the notional volume. For example, for a notional volume of 62,600 Bbls, if the settlement price was $25.03, then oil revenues would have decreased by $62,600. Conversely, if the settlement price was $23.03, oil revenues would have increased by $62,600.

We report average oil, natural gas and NGL prices including the effects of quality, gathering and transportation costs as well as the net effect of monthly oil and natural gas hedge settlements. The following table sets forth our oil, natural gas and NGL prices, both realized before monthly hedge settlements and realized including monthly hedge settlements, the net effects of the monthly settlements of our oil and natural gas price hedges on revenue, and effects of the amortization of gains attributable to gains recognized in prior periods from derivative ineffectiveness:

	Year Ended December 31,		
	2000	2001	2002
	(In thousands, except per unit amounts)		
Average price per Bbl of oil—realized before monthly hedge settlements	$ 29.24	$ 23.39	**$ 23.90**
Average price per Bbl of oil—realized including monthly hedge settlements	27.39	24.17	**20.50**
Average price per Bbl of NGLs—realized before monthly hedge settlements	24.60	17.70	**17.98**
Average price per Bbl of NGLs—realized including monthly hedge settlements	24.60	17.70	**17.98**
Average price per Mcf of natural gas—realized before monthly hedge settlements	3.81	3.53	**2.84**
Average price per Mcf of natural gas—realized including monthly hedge settlements	3.72	4.20	**2.59**
Increase (reduction) in revenue of monthly hedge settlements	(1,141)	6,273	**(7,704)**

Interest Rate Risk.

At December 31, 2002, our exposure to interest rates related primarily to borrowings under our credit agreements and interest earned on short-term investments. As of December 31, 2002, we were not using any derivatives to manage interest rate risk. Interest is payable on borrowings under the credit agreements based on a floating rate which can be locked-in for periods of up to three months, as more fully described in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources." If short-term interest rates would have averaged 1% higher during the year ended December 31, 2002, our interest expense would have increased by approximately $754,000. This amount was determined by applying the hypothetical interest rate change of 1% to our average outstanding borrowings under the credit agreements during the year ended December 31, 2002.

Equity Price Risk.

Our investments in marketable securities are recorded at market value. We consider these investments to be "available for sale", which means that unrealized gains and losses are excluded from earnings and included in other comprehensive income unless the decline in the fair value of the investments is "other than temporary". During the year ended December 31, 2002, we determined that a portion of the decline in two of our investments in marketable securities was "other than temporary" and, as a result, we recognized a non-cash pre-tax impairment expense of $1.1 million. At December 31, 2002, the market value of our investments in marketable securities was $1.8 million. A temporary change in value of 10% would result in a $180,000 change in the market value and a corresponding adjustment to other comprehensive income of $180,000. An "other than temporary" decline in value of 10% would result in a $180,000 reduction in the market value and a corresponding non-cash pre-tax impairment expense of $180,000. As of December 31, 2002, we were not using any derivatives to manage equity price risk.

Foreign Currency Exchange Rate Risk.

We account for a significant portion of our business in Canadian dollars. We are therefore subject to foreign currency exchange rate risk on cash flows of our Canadian operations that are not denominated in Canadian dollars. Presently, a significant portion of the sales of our Canadian oil and natural gas is denominated in U.S. dollars. Foreign currency exchange gains and/or losses related to these transactions have not been significant. The borrowings under our Canadian credit facility are denominated in Canadian dollars. The asset and liability balances of our Canadian business are translated monthly using current exchange rates, with any resulting unrealized translation gains or losses included in other comprehensive income. The unrealized foreign translation gain for the year ended December 31, 2002, was $708,000. As of December 31, 2002, we were not using any derivatives to manage foreign currency exchange rate risk.

Other Market Risk.

We discontinued hedge accounting for our Enron derivatives effective November 30, 2001, and recognized a charge of $10.7 million for the impairment of the associated Enron derivative asset. At December 31, 2001 and 2002, we have valued our asset from Enron at $2.8 million, or approximately 20% of the value on the day we terminated our positions. This valuation is based on informal offers we have received for our position with Enron and other market information. We will continue to monitor activities related to Enron and may adjust the value of our derivative in the future based on new developments and market information.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

EXCO RESOURCES, INC.

INDEX TO FINANCIAL STATEMENTS

Contents

REPORT OF INDEPENDENT ACCOUNTANTS

The Board of Directors
EXCO Resources, Inc.

We have audited the accompanying consolidated balance sheets of EXCO Resources, Inc. as of December 31, 2001 and 2002, and the related consolidated statements of operations, cash flows, changes in stockholders' equity, and comprehensive income (loss) 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. 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, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of EXCO Resources, Inc. at December 31, 2001 and 2002, and the consolidated results of its operations and its 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.

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

As discussed in Note 2 to the consolidated financial statements, EXCO Resources, Inc. adopted Statements of Financial Accounting Standards No. 141 "Business Combinations" in 2001 and No. 142 "Goodwill and Intangible Assets" in 2002.

/s/ ERNST & YOUNG LLP

Dallas, Texas
February 28, 2003
except for Note 2 and Note 14, as to which the dates are
June 27, 2003 and March 11, 2003, respectively

EXCO RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

	December 31, 2001	December 31, 2002
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 1,856	$ **1,942**
Accounts receivable:		
Oil and natural gas sales	6,151	**12,299**
Joint interest	4,156	**1,889**
Interest and other	3,563	**7,343**
Oil and natural gas hedge derivatives	696	**—**
Marketable securities	2,598	**1,823**
Other	2,101	**902**
Total current assets	21,121	**26,198**
Proved developed oil and natural gas properties (full cost accounting method)	184,837	**202,522**
Accumulated depreciation, depletion and amortization	(75,110)	**(93,203)**
Proved developed oil and natural gas properties, net	109,727	**109,319**
Lease and well equipment (full cost accounting method)	20,116	**35,565**
Accumulated depreciation, depletion and amortization	(189)	**(5,883)**
Lease and well equipment, net	19,927	**29,682**
Unproved intangible oil and natural gas properties	6,647	**4,979**
Intangible acquired proved leaseholds	28,936	**76,430**
Accumulated depreciation, depletion and amortization	(402)	**(10,459)**
Acquired proved leaseholds, net	28,534	**65,971**
Office and field equipment, net	966	**1,030**
Deferred financing costs	1,249	**1,100**
Oil and natural gas hedge derivatives	—	**140**
Other assets	2,885	**2,755**
Total assets	$ 191,056	$ **241,174**

See Note 2. "Intangible Acquired Proved Leaseholds and Lease and Well Equipment" for a discussion of certain reclassifications made to the Consolidated Balance Sheets.

EXCO RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

	December 31, 2001	December 31, 2002
	(In thousands, except share data)	
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 11,008	$ **21,821**
Revenues and royalties payable	2,186	**3,353**
Accrued interest payable	128	**95**
Oil and natural gas hedge derivatives	—	**7,924**
Total current liabilities	13,322	**33,193**
Long-term debt	44,994	**97,943**
Deferred abandonment	1,466	**2,176**
Deferred income taxes	10,895	**7,978**
Commitments and contingencies	—	**—**
Stockholders' equity:		
Preferred stock, $.01 par value: Authorized shares—10,000,000 Issued and outstanding shares—5,004,869 at December 31, 2001 and 2002	101,175	**101,175**
Common stock, $.02 par value: Authorized shares—25,000,000 Issued and outstanding shares—7,172,587 and 7,262,953 at December 31, 2001 and 2002, respectively	143	**145**
Additional paid-in capital	51,138	**53,107**
Deferred compensation	—	**(705)**
Notes receivable-employees	(1,117)	**(173)**
Deficit eliminated in quasi-reorganization	(8,799)	**(8,799)**
Retained deficit since December 31, 1997	(29,392)	**(35,600)**
Accumulated other comprehensive income:		
Hedging activities	9,742	**(5,024)**
Foreign currency translation adjustments	(1,646)	**(938)**
Unrealized gain on equity investments	—	**258**
Treasury stock, at cost: 67,446 and 248,434 shares at December 31, 2001 and 2002, respectively	(865)	**(3,562)**
Total stockholders' equity	120,379	**99,884**
Total liabilities and stockholders' equity	$ 191,056	$ **241,174**

See accompanying notes.

EXCO RESOURCES, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2000	2001	2002
	(In thousands, except per share amounts)		
Revenues:			
Oil and natural gas	$ 28,869	$ 61,237	$ **66,446**
Other income	1,252	5,567	**6,654**
Gain on disposition of property, equipment and other assets	538	136	**3**
Total revenues	30,659	66,940	**73,103**
Cost and expenses:			
Oil and natural gas production	9,484	23,914	**29,223**
Depreciation, depletion and amortization	4,949	14,244	**18,558**
General and administrative	2,003	4,806	**10,968**
Interest	1,369	3,133	**3,408**
Impairment of oil and natural gas properties	—	49,575	**17,459**
Impairment of marketable securities	—	—	**1,136**
Uncollectible value of Enron hedges	—	10,669	**—**
Total cost and expenses	17,805	106,341	**80,752**
Income (loss) before income taxes	12,854	(39,401)	**(7,649)**
Income tax expense (benefit)	4,400	(54)	**(6,682)**
Net income (loss)	8,454	(39,347)	**(967)**
Dividends on preferred stock	—	2,653	**5,256**
Earnings (loss) on common stock	$ 8,454	$ (42,000)	$ **(6,223)**
Basic earnings (loss) per share	$ 1.23	$ (5.96)	$ **(0.88)**
Diluted income (loss) per share	$ 1.18	$ (5.96)	$ **(0.88)**
Weighted average number of common and common equivalent shares outstanding:			
Basic	6,835	7,046	**7,061**
Diluted	7,122	7,046	**7,061**

See accompanying notes.

EXCO RESOURCES, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2000	2001	2002
		(In thousands)	
Operating Activities:			
Net income (loss)	$ 8,454	$ (39,347)	$ **(967)**
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	4,949	14,638	**18,558**
Impairment of oil and natural gas properties	—	49,575	**17,459**
Impairment of marketable securities	—	—	**1,136**
Deferred income taxes	1,283	(1,211)	**(4,011)**
Income from derivative ineffectiveness and terminated hedges	—	(4,147)	**(6,291)**
Allowance for uncollectible value of Enron hedges	—	10,669	**—**
Other, net	(538)	(136)	**444**
Cash flow before changes in working capital	14,148	30,041	**26,328**
Effect of changes in:			
Accounts receivable	11,477	(470)	**(7,562)**
Other current assets	(1,912)	(2,655)	**1,310**
Accounts payable and other current liabilities	3,584	(1,000)	**11,584**
Net cash provided by operating activities	27,297	25,916	**31,660**
Investing Activities:			
Additions to oil and natural gas properties and equipment	(67,534)	(90,876)	**(81,854)**
Acquisition of Addison Energy Inc.	—	(44,864)	**—**
Investment in EXUS Energy, LLC	257	—	**—**
Other investing activities	(735)	570	**(172)**
Proceeds from disposition of property and equipment	1,493	1,399	**5,089**
Net cash used in investing activities	(66,519)	(133,771)	**(76,937)**
Financing Activities:			
Proceeds from long-term debt	50,536	165,463	**70,356**
Payments on long-term debt	(12,994)	(162,484)	**(17,910)**
Proceeds from issuance of preferred stock	—	101,175	**—**
Principal and interest on notes receivable—employees	1	615	**944**
Deferred financing costs	(381)	(1,731)	**(551)**
Proceeds from exercise of stock options and warrant	288	2,506	**1,027**
Purchases of treasury stock	—	(761)	**(2,802)**
Issuance of treasury stock	—	—	**120**
Preferred stock dividends	—	(2,653)	**(5,256)**
Net cash provided by financing activities	37,450	102,130	**45,928**
Net increase (decrease) in cash	(1,772)	(5,725)	**651**
Effect of exchange rates on cash and cash equivalents	—	(619)	**(565)**
Cash at beginning of year	9,972	8,200	**1,856**
Cash at end of year	$ 8,200	$ 1,856	$ **1,942**
Supplemental Cash Flow Information:			
Interest paid	$ 1,300	$ 2,667	$ **3,520**
Income taxes paid	$ —	$ 6,350	$ **—**

See accompanying notes.

EXCO RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	5% Preferred Stock		Common Stock									
	Number of Shares	Amount	Number of Shares	Amount	Additional Paid-In Capital	Deferred Compensation	Notes Receivable-Officers and Employees	Deficit Eliminated	Retained Earnings (Deficit)	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
							(In thousands)					
Balance on December 31, 1999	—	$ —	6,805	$ 136	$ 46,941	$ —	$ (1,552)	$ (8,799)	$ 4,154	$ —	$ —	$ 40,880
Interest income on notes receivable—officers	—	—	—	—	—	—	(105)	—	—	—	—	(105)
Interest payment on notes receivable—officers	—	—	—	—	—	—	106	—	—	—	—	106
Exercise of options	—	—	48	1	287	—	—	—	—	—	—	288
Realization of deferred tax asset	—	—	—	—	72	—	—	—	—	—	—	72
Realization of stock warrant value	—	—	—	—	200	—	—	—	—	—	—	200
Purchase of treasury stock, at cost	—	—	—	—	—	—	—	—	—	(104)	—	(104)
Net income	—	—	—	—	—	—	—	—	8,454	—	—	8,454
Balance on December 31, 2000	—	—	6,853	137	47,500	—	(1,551)	(8,799)	12,608	(104)	—	49,791
Issuance of 5% convertible preferred stock	5,005	101,175	—	—	—	—	—	—	—	—	—	101,175
Exercise of stock options and warrant	—	—	270	5	2,682	—	—	—	—	—	—	2,687
Issuance of restricted stock	—	—	50	1	909	—	—	—	—	—	—	910
Realization of deferred tax asset	—	—	—	—	47	—	—	—	—	—	—	47
Principal and interest payments on notes receivable—employees	—	—	—	—	—	—	615	—	—	—	—	615
Notes issued by employees	—	—	—	—	—	—	(181)	—	—	—	—	(181)
Purchase of treasury stock	—	—	—	—	—	—	—	—	—	(761)	—	(761)
Dividends on preferred stock ($.53 per share)	—	—	—	—	—	—	—	—	(2,653)	—	—	(2,653)
Net loss	—	—	—	—	—	—	—	—	(39,347)	—	—	(39,347)
Other comprehensive income:												
Foreign currency translation adjustment	—	—	—	—	—	—	—	—	—	—	(1,646)	(1,646)
Hedging activities:												
Cumulative effect of change in accounting principal	—	—	—	—	—	—	—	—	—	—	(1,068)	(1,068)
Reclassification adjustments for settled contracts	—	—	—	—	—	—	—	—	—	—	(10,687)	(10,687)
Changes in fair value of outstanding hedge positions	—	—	—	—	—	—	—	—	—	—	22,843	22,843
Amortization of gains from terminated hedges	—	—	—	—	—	—	—	—	—	—	(1,346)	(1,346)
Balance on December 31, 2001	5,005	101,175	7,173	143	51,138	—	(1,117)	(8,799)	(29,392)	(865)	8,096	120,379
Exercise of stock options	—	—	90	2	1,025	—	—	—	—	—	—	1,027
Stock-based compensation expense	—	—	—	—	—	239	—	—	—	—	—	239
Deferred compensation	—	—	—	—	944	(944)	—	—	—	—	—	—
Interest income on notes receivable—employees	—	—	—	—	—	—	(63)	—	—	—	—	(63)
Principal and interest payments on notes receivable—employees	—	—	—	—	—	—	1,007	—	—	—	—	1,007
Purchase of treasury stock	—	—	—	—	—	—	—	—	—	(2,802)	—	(2,802)
Issuance of treasury stock	—	—	—	—	—	—	—	—	15	105	—	120
Dividends on preferred stock ($1.05 per share)	—	—	—	—	—	—	—	—	(5,256)	—	—	(5,256)
Net loss	—	—	—	—	—	—	—	—	(967)	—	—	(967)
Other comprehensive income:												
Foreign currency translation adjustment	—	—	—	—	—	—	—	—	—	—	708	708
Unrealized loss on equity investments	—	—	—	—	—	—	—	—	—	—	(878)	(878)
Reclassification adjustments for impairment of marketable securities	—	—	—	—	—	—	—	—	—	—	1,136	1,136
Hedging activities:												
Reclassification adjustments for settled contracts	—	—	—	—	—	—	—	—	—	—	8,197	8,197
Changes in fair value of outstanding hedge positions	—	—	—	—	—	—	—	—	—	—	(15,987)	(15,987)
Amortization of gains from terminated contracts	—	—	—	—	—	—	—	—	—	—	(6,976)	(6,976)
Balance on December 31, 2002	**5,005**	**$ 101,175**	**7,263**	**$ 145**	**$ 53,107**	**$ (705)**	**$ (173)**	**$ (8,799)**	**$ (35,600)**	**$ (3,562)**	**$ (5,704)**	**$ 99,884**

See accompanying notes.

EXCO RESOURCES, INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2000	2001	2002
		(In thousands)	
Net income (loss)	$ 8,454	$ (39,347)	**$ (967)**
Other comprehensive income (loss):			
Hedging activities:			
Cumulative effect of change in accounting principle — January 1, 2001	—	(1,068)	**—**
Effective changes in fair value	—	22,843	**(15,987)**
Reclassification adjustments for settled contracts	—	(10,687)	**8,197**
Amortization of terminated contracts	—	(1,346)	**(6,976)**
Total hedging activities	—	9,742	**(14,766)**
Foreign currency translation adjustment	—	(1,646)	**708**
Reclassification adjustment for impairment of marketable securities	—	—	**1,136**
Unrealized loss on equity investments	—	—	**(878)**
Total comprehensive income (loss)	$ 8,454	$ (31,251)	**$ (14,767)**

See accompanying notes.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Organization

EXCO Resources, Inc., (the Company), a Texas corporation, was formed in 1955. Our operations consist primarily of acquiring interests in producing oil and natural gas properties located in the continental United States and Canada. We also act as the operator of some of these properties and receive overhead reimbursement fees as a result.

Principles of Consolidation

The accompanying consolidated financial statements include the financial statements of EXCO Resources, Inc. and its subsidiaries. We accounted for our investment in Pecos-Gomez, L.P., which ceased operations during 2001 with all remaining net assets distributed to the partners, using the proportional method of consolidation. Under this method, only our combined 55.13742% interest in the partnership is reflected in the financial statements with no recording of minority interest. All inter-company transactions have been eliminated.

Functional Currency

The assets, liabilities and operations of Addison Energy Inc. (Addison), our Canadian subsidiary, are measured using the Canadian dollar as the functional currency. These assets and liabilities are translated into U.S. dollars using end-of-period exchange rates. Revenue and expenses are translated into U.S. dollars at the average exchange rates in effect during the period. Translation adjustments are deferred and accumulated in other comprehensive income.

Quasi-Reorganization

Effective December 31, 1997, we effected a quasi-reorganization by applying approximately $8.8 million of our additional paid-in capital account to eliminate our accumulated deficit. Our board of directors decided to effect a quasi-reorganization given the change in management, the infusion of new equity capital and an increase in activities. Our accumulated deficit was primarily related to past operations and properties that have been sold or abandoned. We did not adjust the historical carrying values of our assets and liabilities in connection with the quasi-reorganization.

Management Estimates

In preparing financial statements in conformity with accounting principles generally accepted in the United States, we are required to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses during the reporting period. The most significant estimates pertain to proved oil, natural gas and NGL reserve volumes, future development, dismantlement and abandonment costs, valuation of deferred tax assets, estimates relating to certain oil, natural gas and NGL revenues and expenses and the fair market value of derivatives and equity securities. Actual results may differ from management's estimates.

Cash Equivalents and Marketable Securities

We consider all highly liquid investments with maturities of three months or less when purchased, to be cash equivalents.

We have evaluated our investment policies in accordance with Statement of Financial Accounting Standards (SFAS) No. 115, "Accounting for Certain Investments in Debt and Equity Securities" and

1. Summary of Significant Accounting Policies (Continued)

determined that all of our investment securities, other than cash equivalents, are to be classified as available for sale. Available for sale securities are carried at fair value, with the unrealized gains and losses reported in other comprehensive income. Realized gains and losses are included in other income on the consolidated statement of operations. Declines in value that are considered to be "other than temporary" on available for sale securities are shown separately on the consolidated statement of operations. Realized gains and losses are determined using the first-in, first-out method.

Concentration of Credit Risk and Accounts Receivable

Financial instruments that potentially subject us to a concentration of credit risk consist principally of cash, trade receivables and our hedging and derivative financial instruments. We place our cash with high credit quality financial institutions. We sell oil and natural gas to various customers. In addition, we participate with other parties in the drilling, completion and operation of oil and natural gas wells. Substantially all of our accounts receivable are due from either purchasers of oil, natural gas or NGLs or participants in oil and natural gas wells for which we serve as the operator. Generally, operators of oil and natural gas properties have the right to offset future revenues against unpaid charges related to operated wells. Oil, natural gas and NGL sales are generally unsecured. We have provided for credit losses in the financial statements and these losses have been within management's expectations. The allowance for doubtful accounts receivable aggregated $111,000 and $220,000 at December 31, 2001 and 2002, respectively. We place our hedging and derivative financial instruments with financial institutions and other firms that we believe have high credit ratings. For a discussion of the credit risks associated with our hedging activities, please see "Note 10. Hedging Activities."

Hedging and Derivative Financial Instruments

In connection with the incurrence of debt related to our acquisition activities and to protect against commodity price fluctuations to achieve a more predictable cash flow, our management has adopted a policy of hedging oil and natural gas prices whenever such prices are in excess of the prices anticipated in our operating budget and profit plan through the use of commodity futures, options and swap agreements. These derivatives are not held for trading purposes.

We adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" on January 1, 2001. In accordance with the transition provisions of SFAS 133, we recorded a cumulative-effect loss in other comprehensive income of $1.1 million to recognize the fair value of our derivatives designated as cash-flow hedging instruments at the date of adoption.

On the date the derivative contract is entered into, we designate the derivative as a hedge. All of our derivative instruments at December 31, 2000, 2001 and 2002, were designated as cash flow hedges. Changes in the fair value of a derivative that is highly effective as a cash flow hedge are recorded in other comprehensive income, until earnings are affected by the variability of cash flows.

We formally document all relationships between hedging instruments and hedged items, as well as our risk-management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives that are designated as cash flow hedges to forecasted transactions. We also formally assess, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. When it is determined that a derivative is not highly effective as a hedge or that it has ceased to be a highly effective hedge, we discontinue hedge accounting prospectively, as discussed below.

1. Summary of Significant Accounting Policies (Continued)

We discontinue hedge accounting prospectively when: (1) it is determined that the derivative is no longer highly effective in offsetting changes in cash flows of a hedged item; (2) the derivative expires or is sold, terminated or exercised; (3) the derivative is not designated as a hedge instrument, because it is unlikely that a forecasted transaction will occur; or (4) management determines that designation of the derivative as a hedge instrument is no longer appropriate.

When hedge accounting is discontinued because it is probable that a forecasted transaction will not occur, the derivative will continue to be carried on the balance sheet at its fair value, and gains and losses that were accumulated in other comprehensive income will be recognized immediately in earnings. In all other situations in which hedge accounting is discontinued, the derivative will be carried at its fair value on the balance sheet, with changes in its fair value recognized in current-period earnings. Amounts previously recognized in other comprehensive income will remain there until the previously hedged item affects earnings. Please see "Note 10. Hedging Activities" for a discussion of certain derivative transactions for which hedge accounting was discontinued during 2001.

For the years ended December 31, 2001 and 2002, we recorded as other income in the statement of operations, a gain of $3.5 million and a loss of $886,000, respectively, from hedge ineffectiveness. For the years ended December 31, 2001 and 2002, we also recorded as other income in the statement of operations $1.3 million and $7.0 million, respectively, from derivative transactions for which hedge accounting was discontinued.

Oil and Natural Gas Properties

We have recorded oil and natural gas properties at cost using the full cost method of accounting. Under the full cost method, all costs associated with the acquisition, exploration or development of oil and natural gas properties are capitalized as part of the full cost pool. Capitalized costs are limited to the aggregate of the after-tax present value of future net revenues plus the lower of cost or fair market value of unproved properties. The full cost pool is comprised of lease and well equipment and exploration and development costs incurred, plus intangible acquired proved leaseholds. See Note 2 for further discussion of intangible acquired proved leaseholds.

Unproved intangible oil and natural gas properties are excluded from the calculation of depreciation, depletion and amortization until it is determined whether or not proved reserves can be assigned to such properties. At December 31, 2001 and 2002, the $6.6 million and $5.0 million, respectively, in unproved intangible oil and natural gas properties resulted from the allocation of the purchase price of Canadian properties to undeveloped acreage and possible and probable reserves. We assess our unproved intangible oil and natural gas properties for impairment on a quarterly basis.

Depreciation, depletion and amortization of evaluated oil and natural gas properties is provided using the unit-of-production method based on total proved reserves, as determined by independent petroleum reservoir engineers. See Note 2 for the amount of depreciation, depletion and amortization attributed to intangible acquired proved leaseholds.

Sales, dispositions and other oil and natural gas property retirements are accounted for as adjustments to the full cost pool, with no recognition of gain or loss unless the disposition would significantly alter the amortization rate.

At the end of each quarterly period, the unamortized cost of proved oil and natural gas properties, net of related deferred income taxes, is limited to the sum of the estimated future net revenues from proved properties using current period-end prices discounted at 10%, adjusted for related income tax

1. Summary of Significant Accounting Policies (Continued)

effects (ceiling test). This calculation is done separately for the United States and Canadian full cost pools.

The calculation of the ceiling test is based upon estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, and plan of development. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

As a result of low oil and natural gas prices at September 30, 2001 and December 31, 2001, we recorded pre-tax non-cash ceiling test write-downs during the year ended December 31, 2001, totaling approximately $49.6 million (of which $28.7 million was from the United States full cost pool and $20.9 million was from the Canadian full cost pool). As those impairments did not involve leaseholds acquired since June 30, 2001, no amount of these impairments was attributed to acquired proved leaseholds (see Note 2). As a result of lower prices for Canadian natural gas at June 30, 2002, we had a pre-tax non-cash ceiling test write-down of our oil and natural gas properties during the second quarter of 2002 of $17.5 million ($9.7 million after-tax) from our Canadian full cost pool. See Note 2 for the portion of this impairment attributed to intangible acquired proved leaseholds.

Office and Field Equipment

Office and field equipment are capitalized at cost and depreciated on a straight line basis over their estimated useful lives.

Environmental Costs

Environmental costs that relate to current operations are expensed as incurred. Remediation costs that relate to an existing condition caused by past operations are accrued when it is probable that those costs will be incurred and can be reasonably estimated based upon evaluations of currently available facts related to each site.

Deferred Abandonment and Asset Retirement Obligations

Prior to 2003, we provided for future site restoration costs on our Canadian oil and natural gas properties based upon management's estimates. The costs were being recognized over the remaining life of proved reserves by a charge to depreciation, depletion and amortization in the statement of operations with a related increase in the non-current deferred abandonment liability. Actual expenditures for site restoration were charged to the deferred abandonment liability when incurred.

In June 2001, the Financial Accounting Standards Board issued SFAS No. 143, "Accounting for Asset Retirement Obligations". The statement requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time that the obligations are incurred. Upon initial recognition of a liability, that cost should be capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. We will adopt the new rules on asset retirement obligations on January 1, 2003, for both our U.S. and Canadian operations. Application of the new rules is expected to result in an increase in net proved developed and undeveloped oil and natural gas properties of approximately $11.2 million, recognition of an asset retirement obligation

1. Summary of Significant Accounting Policies (Continued)

liability of approximately $10.2 million, a reduction in deferred income tax liability of approximately $700,000, and a cumulative effect of adoption that will increase net income and stockholder's equity by approximately $1.7 million.

Revenue Recognition and Gas Imbalances

We use the sales method of accounting for oil and natural gas revenues. Under the sales method, revenues are recognized based on actual volumes of oil and natural gas sold to purchasers. Gas imbalances at December 31, 2001 and 2002 were not significant; however, we have recorded a liability of $92,000 at December 31, 2002 for those wells where there are insufficient reserves to retire the imbalance.

Capitalization of Internal Costs

We capitalize as part of our proved developed oil and natural gas properties a portion of salaries paid to employees who are directly involved in the acquisition and exploitation of oil and natural gas properties. During the years ended December 31, 2000, 2001, and 2002, we have capitalized $500,000, $1.1 million, and $1.1 million, respectively.

Overhead Reimbursement Fees

We have classified fees from overhead charges billed to working interest owners, including ourselves, of $1.5 million, $2.9 million and $2.9 million for the years ended December 31, 2000, 2001 and 2002, respectively, as a reduction of general and administrative expenses in the accompanying statements of operations. Our share of these charges were $894,000, $1.8 million and $1.8 million in 2000, 2001, and 2002, respectively, and are classified as oil and natural gas production costs.

Earnings Per Share

SFAS No. 128, "Earnings per Share," requires presentation of two calculations of earnings per common share. Basic earnings per common share equals earnings on common stock divided by weighted average common shares outstanding during the period. Diluted earnings per common share equals net income divided by the sum of weighted average common shares outstanding during the period plus any dilutive common stock equivalents assumed to be issued. Common stock equivalents are shares assumed to be issued if our 5% convertible preferred stock were converted and our outstanding stock options and warrants, if any, were exercised.

For the year ended December 31, 2000, employee and director stock options increased the weighted average number of shares outstanding by approximately 287,000 shares for the purpose of calculating diluted earnings per share. Since we reported a net loss for the years ended December 31, 2001 and 2002, our common stock equivalents are considered to be anti-dilutive and are not considered in the earnings per share calculation. For the year ended December 31, 2001, employee and director stock options, and our 5% convertible preferred stock would have increased the weighted average number of shares outstanding by approximately 469,000 shares and 2,537,000 shares, respectively. For the year ended December 31, 2002, employee and director stock options, and our 5% convertible preferred stock would have increased the weighted average number of shares outstanding by approximately 467,000 shares and 5,004,869 shares, respectively.

1. Summary of Significant Accounting Policies (Continued)

Stock Options and Benefit Plan

SFAS No. 123, "Accounting for Stock-Based Compensation" defines a fair value based method of accounting for employee stock compensation plans, but allows for the continuation of the intrinsic value based method of accounting to measure compensation cost prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25). For companies electing not to change their accounting, SFAS 123 requires pro forma disclosures of earnings and earnings per share as if the change in accounting provision of SFAS 123 has been adopted.

We have elected to continue to utilize the accounting method prescribed by APB 25, under which no compensation cost has been recognized, and adopt the disclosure requirements of SFAS 123. As a result, SFAS 123 has no effect on our financial condition or our results of operations at December 31, 2000, 2001 and 2002. Stock based compensation expense reflected in the table below for the year ended December 31, 2002, is a result of options issued under our 1998 Stock Option Plan that were issued subject to our shareholders' approval and options that were issued to the management and key employees of Addison. See "Note 6. Stock Transactions" for a further description of these stock options.

Had compensation costs for these plans been determined consistent with SFAS 123, our net income (loss) and earnings per share (EPS) would have been adjusted to the following pro forma amounts:

		December 31,		
		2000	2001	2002
		(In thousands, except per share amounts)		
Stock based compensation expense (net of taxes)	As Reported	$ —	$ —	**$ 991**
	Pro Forma	$ 678	$ 1,118	**$ 2,487**
Net income (loss)	As Reported	$ 8,454	$ (39,347)	**$ (967)**
	Pro Forma	$ 7,776	$ (40,465)	**$ (2,463)**
Basic EPS	As Reported	$ 1.23	$ (5.96)	**$ (0.88)**
	Pro Forma	$ 1.14	$ (6.12)	**$ (1.09)**
Diluted EPS	As Reported	$ 1.18	$ (5.96)	**$ (0.88)**
	Pro Forma	$ 1.09	$ (6.12)	**$ (1.09)**

We sponsor a 401(k) plan for our U.S. employees and match up to 100% of employee contributions based on years of service with us. Our matching contributions of $44,000, $100,000 and $151,000 for the years ended December 31, 2000, 2001 and 2002, respectively, have been included as general and administrative expense.

Reclassified Prior Year Amounts

Certain prior year amounts have been reclassified to conform to current year presentation.

2. Intangible Acquired Proved Leaseholds and Lease and Well Equipment

SFAS No. 141, "Business Combinations", and SFAS No. 142, "Goodwill and Intangible Assets", were issued in June 2001and became effective for us on July 1, 2001and January 1, 2002, respectively. In connection with the SEC review process of our proxy materials for the upcoming shareholders' meeting, we have determined that these standards require that mineral use rights, such as leasehold interests, be separately classified on the balance sheet for all leaseholds purchased subsequent to June 30, 2001. As a result of this, we have also determined that lease and well equipment purchased

2. Intangible Acquired Proved Leaseholds and Lease and Well Equipment (Continued)

subsequent to June 30, 2001 also be separately classified on the balance sheet. Leasehold interests and lease and well equipment acquired prior to the adoption of SFAS No. 141 were not separately valued at the time of purchase; therefore, consistent with Emerging Issues Task Force Issue D-100, we were unable to classify leasehold interests and lease and well equipment acquired prior to July 1, 2001 as an intangible asset.

Under the full cost pool rules these intangible acquired proved leaseholds and lease and well equipment continue to be included in the full cost pool for purposes of depreciation, depletion and amortization (DD&A) as well as impairment. The following table details the activity related to intangible acquired proved leaseholds for acquisitions since June 30, 2001, including the amount of DD&A and impairment allocated to the intangible acquired proved leaseholds in 2001 and 2002 (in thousands):

Acquisition	Cost	Accumulated DD&A
Pecos County Acquisition	$ 8,814	$ —
PrimeWest Acquisition	18,601	—
Other leaseholds acquired since July 1, 2001	1,521	—
Depreciation, depletion and amortization	—	402
Balance at December 31, 2001	28,936	402
Medicine River Acquisition	20,503	—
DJ Basin Acquisition	20,069	—
Other leaseholds acquired in 2002	6,774	—
Depreciation, depletion and amortization	—	3,436
Impairment of leaseholds acquired	—	6,809
Foreign exchange conversion	148	(188)
Balance at December 31, 2002	$76,430	$10,459

The 2002 impairment charge was allocated to the Canadian tangible assets and intangible acquired proved leaseholds based on original cost. We believe that the 2001 oil and gas property impairments did not involve assets purchased subsequent to June 30, 2001 and thus no portion of the 2001 impairment has been allocated to intangible acquired proved leaseholds. The reclassifications of amounts to intangible acquired proved leaseholds and lease and well equipment from proved developed oil and natural gas properties had no effect on depreciation, depletion or amortization for either of the years ended December 31, 2001 and 2002 or on total assets, equity and working capital at December 31, 2001 and 2002.

2. Intangible Acquired Proved Leaseholds and Lease and Well Equipment (Continued)

Based on our estimate of future production in the next five years, our estimate of the amortization of intangible acquired proved leaseholds that will be recognized during the next five years is as follows (in thousands):

Year	Amount
2003	$ 5,060
2004	5,820
2005	5,483
2006	4,777
2007	4,212
Thereafter	40,619

The amounts assigned to intangible acquired proved leaseholds have been calculated by first calculating the portion of the purchase price to be allocated to oil and natural gas properties, which is generally based on management's estimate of the discounted cash flows of the proved reserves, and then deducting from that the amount that management believes is the fair market value of the lease and well equipment acquired in each purchase.

Unproved intangible oil and natural gas properties include costs to acquire a lease or other interest representing the right to explore or extract oil or natural gas from an unproved property. Under Regulation S-X of the SEC, the cost of investments in unproved properties may be excluded from costs to be amortized until it is determined whether or not proved reserves can be added to the property. At that time, the cost of the unproved intangible oil and natural gas properties are added to the full cost pool and amortized using the unit-of-production method based on total proved reserves. Until such time as the development work is completed to determine whether or not there are proved reserves that can be added to the property or we determine that we will not perform the necessary development work, we are not able to estimate the amount of amortization that would be incurred over the next five years related to unproved intangible oil and natural gas properties.

3. Marketable Securities

Marketable securities at December 31, 2001 and 2002, consist primarily of common stock investments in public corporations, which are classified as available for sale securities. At December 31, 2001, our cost basis of marketable securities was $2.6 million while the aggregate fair value was $2.7 million. At December 31, 2002, our cost basis of marketable securities was $2.7 million while the aggregate fair value was $1.8 million.

3. Marketable Securities (Continued)

At December 31, 2002, we had gross unrealized holding gains from available for sale securities of $258,000. We had no gross unrealized holding losses from available for sale securities at December 31, 2002. Investment income is presented in the following table:

	December 31,		
	2000	2001	2002
	(In thousands)		
Gross proceeds from sales of marketable securities	$ 39	$ 993	$ —
Gross realized gains from sales of marketable securities	15	107	—
Gross realized losses from sales of marketable securities	—	—	**(1)**
Unrealized net loss included in other comprehensive income	—	—	**(878)**
Reclassification adjustment for impairment of marketable securities	—	—	**1,136**

4. Long-Term Debt

Long-term debt is summarized as follows:

	December 31,	
	2001	2002
	(In thousands)	
Notes payable	$ 44,994	**$ 97,943**
Less current maturities	—	**—**
Long-term debt	$ 44,994	**$ 97,943**

Credit Agreements

We have a U.S. credit agreement and a Canadian credit agreement. The U.S. credit agreement is with Bank One, NA, as administrative agent, BNP Paribas, as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and certain financial institutions as lenders. The Canadian credit agreement is with Bank One, NA, Canada Branch, as administrative agent, BNP Paribas (Canada), as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and certain financial institutions as lenders. The credit agreements mature on April 30, 2004.

U.S. Credit Agreement. Our restated U.S. credit agreement provides for borrowings of up to $124.0 million under a revolving credit facility with a borrowing base of $82.0 million. The borrowing base is to be redetermined as of May 1, 2003, and each November 1 and May 1 thereafter. At December 31, 2002, we had approximately $34.4 million of outstanding indebtedness, letter of credit commitments of $310,000, and approximately $47.3 million available for borrowing under our U.S. credit agreement. Borrowings under the credit agreement are secured by a first lien mortgage providing a security interest in 90% of our U.S. oil and natural gas properties. At our election, interest on borrowings may be either (i) the greater of the administrative agent's prime rate or the federal funds effective rate plus an applicable margin or (ii) LIBOR (London InterBank Offered Rate) plus an applicable margin.

As part of the financing of the acquisition of Addison, the U.S. credit agreement provided for a bridge loan to us in the amount of $16.0 million. We repaid the $16.0 million borrowed under the bridge loan on June 29, 2001, from net proceeds from our 5% convertible preferred stock offering and

4. Long-Term Debt (Continued)

from proceeds from the exercise of employee stock options and the 200,000 share warrant (see "Note 4. Stock Transactions"). By the terms of the U.S. credit agreement, we may not make any additional borrowings under the bridge loan after it has been repaid.

Canadian Credit Agreement. Our restated Canadian credit agreement provides for borrowings of up to U.S. $157.5 million under a revolving credit facility with a borrowing base of U.S. $83.0 million. The borrowing base is to be redetermined as of May 1, 2003, and each November 1 and May 1 thereafter. At December 31, 2002, we had approximately U.S. $63.5 million of outstanding indebtedness and approximately $19.5 million available for borrowing under our Canadian credit agreement. Borrowings under the credit agreement are secured by a first lien mortgage providing a security interest in 90% of our Canadian oil and natural gas properties. At our election, interest on borrowings may be either (i) the Canadian prime rate plus an applicable margin or (ii) the Banker's Acceptance rate plus an applicable margin.

The U.S. and the Canadian credit agreements contain certain financial covenants and other restrictions which require that we:

- maintain a ratio of our consolidated current assets to consolidated current liabilities (as defined under our credit agreements) of at least 1.0 to 1.0 at the end of any fiscal quarter;
- maintain a minimum consolidated tangible net worth of not less than $48.0 million (adjusted upward by 50% of quarterly net income and 75% of the net proceeds from the issuance of any equity securities after April 26, 2001);
- not permit the ratio of consolidated debt to consolidated total capital to be greater than 65% at the end of each fiscal quarter; and
- not permit the ratio of indebtedness to earnings before interest expense, state and federal taxes, and depreciation, depletion and amortization expense to be more than 3.0 to 1.0 at the end of each fiscal quarter.

Additionally, the credit agreements contain a number of other covenants regarding our liquidity and capital resources, including restrictions on our ability to incur additional indebtedness, restrictions on our ability to pledge assets, and prohibit the payment of dividends on our common stock. As of December 31, 2002, we were in compliance with the covenants contained in the U.S. and Canadian credit agreements.

Dividend Restrictions. We have not paid any cash dividends on our common stock, and we do not anticipate paying cash dividends on our common stock in the foreseeable future. In addition, our credit agreements currently prohibit us from paying dividends on our common stock. If there is a default under our credit agreements, we will not be able to pay dividends on the shares of our 5% convertible preferred stock. Even if our credit agreements permitted us to pay cash dividends, we can make those payments only from our surplus (the excess of the fair value of our total assets over the sum of our liabilities plus our total paid-in share capital). In addition, we can pay cash dividends only if after paying those dividends we would be able to pay our liabilities as they become due.

5. Income Taxes

The income tax provision attributable to our income (loss) before income taxes consists of the following:

	December 31,		
	2000	2001	2002
	(In thousands)		
Current:			
U.S.	$ 2,200	$ 1,157	$ **(2,672)**
Canadian	—	—	—
	2,200	1,157	**(2,672)**
Deferred:			
U.S.	2,200	(1,211)	—
Canadian	—	—	**(4,010)**
	2,200	(1,211)	**(4,010)**
Total income tax (benefit)	$ 4,400	$ (54)	$ **(6,682)**

We have net operating loss carryforwards (NOLs) for income tax purposes that have either been generated from our operations or were purchased in our acquisitions. These NOLs begin to expire in 2003. Our ability to use the purchased NOLs has been significantly restricted because of a change in our ownership, which occurred December 19, 1997, as well as the change in ownership of Rio Grande, Inc. which occurred on March 16, 1999. We estimate that approximately $4.9 million of the purchased NOLs will become available in the future at the rate of approximately $460,000 per year. For financial reporting purposes, a valuation allowance has been recognized to offset the deferred tax assets related to carryforwards prior to our quasi-reorganization. When realized, the tax benefit for those carryforwards will be credited to additional paid-in capital. In 2002, no such amounts were recognized. In addition, a valuation allowance has been recognized to offset all of our remaining U.S. deferred tax assets, including the NOLs generated from our operations.

We have not provided any U.S. deferred income taxes on the undistributed earnings of our Canadian subsidiary based upon the determination that at this time those earnings will be indefinitely reinvested in Canada. As of December 31, 2002, there were no material cumulative undistributed earnings of this subsidiary.

5. Income Taxes (Continued)

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of our deferred tax liabilities and assets are as follows:

	December 31,		
	2000	2001	2002
		(In thousands)	
Deferred tax assets:			
Net operating loss carryforwards—United States	$ 1,984	$ 1,814	**$ 2,719**
Tax basis of oil and natural gas properties in excess of book basis—United States	—	3,280	**771**
Basis difference in fair value of hedges	—	2,482	**(48)**
Credit carryforwards	5	2	**5**
Other	13	41	**46**
Valuation allowance for deferred tax assets	(1,306)	(7,619)	**(3,493)**
Total deferred tax assets	696	—	—
Deferred tax liabilities:			
Book basis of oil and natural gas properties in excess of tax basis—United States	1,907	—	—
Book basis of oil and natural gas properties in excess of tax basis—Canada	—	10,895	**7,978**
Total deferred tax liabilities	1,907	10,895	**7,978**
Net deferred tax liabilities	$ 1,211	$10,895	**$ 7,978**

A reconciliation our income tax provision (benefit) computed by applying the statutory United States federal income tax rate to our income (loss) before income taxes for the years ended December 31, 2000, 2001 and 2002, is presented in the following table:

	December 31,		
	2000	2001	2002
		(In thousands)	
United States federal income taxes (benefit) at statutory rate of 34%	$ 4,374	$ (13,396)	**$ (2,601)**
Increases (reductions) resulting from:			
Adjustments to the valuation allowance	(422)	6,313	**(4,126)**
Rate difference on foreign taxes	—	—	**(860)**
Non-deductible charges	—	7,928	**675**
Other	448	(899)	**230**
Tax provision	$ 4,400	$ (54)	**$ (6,682)**

6. Stock Transactions

Issuance of Common Stock

During the year ended December 31, 2000, two of our directors and three of our employees exercised stock options covering 48,000 shares of our common stock, 46,375 at a strike price of $6.00 per share and 1,625 shares at $6.25 per share. We received net proceeds of approximately $288,400 for these shares all of which was paid in cash.

During the year ended December 31, 2001, 17 of our employees, one of whom is also a director, exercised stock options covering 69,511 shares of our common stock at strike prices ranging from $6.00 per share to $15.125 per share. We received aggregate proceeds of approximately $486,600 for these shares with $305,600 paid in cash and $181,000 being borrowed from us.

During the year ended December 31, 2002, 24 of our employees exercised stock options covering 90,366 shares of our common stock at strike prices ranging from $6.00 per share to $15.50 per share. We received aggregate proceeds of approximately $1,026,200 for these shares all of which was paid in cash.

In 1998 and 1999, we loaned Douglas H. Miller, our Chairman and Chief Executive Officer, a total of $915,625 in order to enable him to exercise stock options granted to him under our 1998 stock option plan. Of the outstanding balance, $465,625 plus accrued interest was due and payable on November 29, 2002, and $450,000 plus accrued interest was due and payable on September 15, 2004. Mr. Miller paid us all outstanding amounts owed under these loans on November 29, 2002. Under the terms of the Sarbanes-Oxley Act of 2002, we can no longer loan money to our executive officers or amend the terms of any agreements that were in place at the time the law was enacted. At December 31, 2002, we had one executive officer with an outstanding loan balance of $60,000. This loan is due on May 18, 2004, and was used to exercise stock options granted under our 1998 Stock Option Plan.

The following table summarizes our stock option activity:

	Stock Options	Weighted Average Exercise Price Per Share
Options outstanding at December 31, 1999	1,066,709	$ 6.02
Granted	414,637	$ 13.77
Expired or canceled	(34,747)	$ 6.01
Exercised	(48,000)	$ 6.01
Options outstanding at December 31, 2000	1,398,599	$ 8.32
Granted	761,625	$ 14.55
Expired or canceled	(40,933)	$ 14.88
Exercised	(69,511)	$ 7.00
Options outstanding at December 31, 2001	2,049,780	$ 10.55
Granted	172,668	$ 16.10
Expired or canceled	(82,251)	$ 13.64
Exercised	(90,366)	$ 11.36
Options outstanding at December 31, 2002	**2,049,831**	**$ 10.85**
Options exercisable at December 31, 2002	**1,502,086**	**$ 9.42**

6. Stock Transactions (Continued)

The present value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model. The following assumptions were used:

Fair market value of stock at date of grant	$6.00 to $20.62
Option exercise prices	$6.00 to $20.62
Option term	10 years
Risk-free rate of return	10-year U.S. Treasury Notes
Company stock volatility	Based upon daily stock prices from January 1, 2000 through December 31, 2002
Company dividend yield	0%
Calculated Black-Scholes values	$2.60 to $8.94 per option

See "Note 1. Summary of Significant Accounting Policies—Stock Options" for a comparison of our net loss and net loss per share as reported and as adjusted for the pro forma effects of determining compensation expense in accordance with SFAS 123.

As part of the consideration paid for the acquisition of the Central Properties, we issued a warrant to Central Resources, Inc. to purchase 200,000 shares of our common stock for $11.00 per share. This warrant was assigned and then exercised on May 21, 2001, for the full 200,000 shares at which time we received $2.2 million cash. We filed a registration statement on Form S-3 with the SEC to register the resale of the 200,000 shares of common stock issued upon the exercise of the warrant. The registration statement was declared effective by the SEC on October 15, 2001.

As an incentive to the management and certain key employees of Addison, the board of directors of Addison established the Addison Energy Inc. Stock Option Plan effective June 30, 2002. Addison stock options were issued as of June 30, 2002, under the plan that, if fully exercised, would allow the participants to own in the aggregate 1,000 shares of Addison common stock, approximately 10% of the shares of common stock in Addison on a fully-diluted basis. The Addison stock options are exercisable for a term of five years from the date of the grant. The Addison stock options are subject to vesting. The vesting schedule is as follows:

Vesting Date	Cumulative Percent Vested
Prior to April 26, 2003	None
April 26, 2003	50%
April 26, 2004	75%
April 26, 2005	100%

The exercise price under the Addison stock option plan as of June 30, 2002 was CDN $1,031.61 per share. The price was determined by using a formula as set forth in the Addison stock option agreement. The formula is based upon:

- The value of Addison's proved reserves;
- The amount of any working capital surplus or deficiency;
- Any capital contributions or distributions made after June 30, 2002;

6. Stock Transactions (Continued)

- Any debt owed to us, owed under the Canadian credit agreement or owed to other third parties;
- The total exercise price of all outstanding Addison stock options under the plan;
- The amount of deferred income tax liability incurred after June 30, 2002;
- A calculated amount to allocate certain general and administrative costs that we incur that also benefit Addison; and
- The ratio of the average trading price of our common stock divided by $18.25.

This formula is to be calculated as of December 31 of each year, beginning December 31, 2002, to determine the value of each share of Addison's common stock.

If an Addison stock option is exercised, we are obligated to purchase the shares of Addison common stock from the employee six months later at the then-current price as calculated using the above formula. Each employee receiving an Addison stock option has entered into an agreement that restricts their ability to sell or transfer any Addison common stock acquired under the Addison stock option plan to any party other than to us.

The Addison stock options will become fully vested and exercisable if any of the following occurs:

- A person, or a group of people acting together, has the right to cast more than 50% of the votes when electing our directors;
- Our shareholders approve a merger or other transaction that would result in our shareholders owning less than 50% of the combined entity; or
- We sell the shares of Addison or substantially all of its assets.

At the time one of these events occurs, we are to perform the above calculation to determine the value of each share of Addison common stock as of the date of the event. We will then pay in cash the difference between the calculated value per share and the Addison stock option exercise price times the number of shares of Addison common stock that the participant has the right to purchase under the Addison stock option plan.

The value of a share of Addison common stock was calculated to be CDN $7,013.94 per share as of December 31, 2002.

The following table summarizes our Addison stock option activity:

	Stock Options	Weighted Average Exercise Price Per Share
Options outstanding at December 31, 2001	0	CDN $ —
Granted	1,000	CDN $ 1,031.61
Expired or canceled	0	—
Exercised	0	—
Options outstanding at December 31, 2002	**1,000**	**CDN $ 1,031.61**

During the year ended December 31, 2002, we recognized U.S. $1.4 million as stock-based compensation expense for the Addison stock option plan.

6. Stock Transactions (Continued)

Issuance of Preferred Stock

We are authorized to issue up to 10,000,000 shares of preferred stock, $.01 par value per share, that the board of directors may issue from time to time in one or more series. With respect to each series of preferred stock, the board is authorized to fix and determine by resolution the number of shares of each series, the designation thereof and all rights and preferences including voting, dividend, conversion, redemption and liquidation rights.

On June 29, 2001, we closed our rights offering to existing shareholders that resulted in the sale of 5,004,869 shares of 5% convertible preferred stock at $21.00 per share. We raised a total of approximately $105.1 million in gross proceeds (approximately $101.2 million in net proceeds after fees and commissions), through the exercise of 4,466,869 rights and the sale of 538,000 shares of 5% convertible preferred stock by dealer managers. We applied approximately $97.6 million of the offering proceeds to pay-off our bank loans and have used the remaining proceeds for general corporate purposes. Dividends on our 5% convertible preferred stock are payable quarterly in cash. Currently, the requirement for such dividend payment is approximately $1.3 million per quarter beginning September 30, 2001. During 2001, preferred stock dividends of approximately $2.7 million were paid. During 2002, preferred stock dividends of approximately $5.3 million were paid. Each share of 5% convertible preferred stock is convertible into one share of our common stock, at the option of the holder, on or before June 30, 2003. On June 30, 2003, each outstanding share of 5% convertible preferred stock will be automatically converted into one share of our common stock.

The remaining authorized but unissued shares of preferred stock are available for future equity financings through issuance to the general public, future acquisitions, stock dividends or splits or for other corporate purposes for which the issuance of preferred shares may be advisable.

7. Commitments and Contingencies

We lease our offices and certain equipment. Our rental expenses were approximately $202,000, $476,000 and $728,000 for 2000, 2001 and 2002, respectively. Our future minimum rental payments under operating leases with remaining noncancellable lease terms at December 31, 2002, are as follows:

	Amount (In thousands)
2003	$ 868
2004	715
2005	650
2006	345
Thereafter	230
	$ 2,808

8. Environmental Regulation

Various federal, state and local laws and regulations covering discharge of materials into the environment, or otherwise relating to the protection of the environment, may affect our operations and the costs of our oil and natural gas exploitation, development and production operations. We do not anticipate that we will be required in the near future to expend amounts material in relation to the financial statements taken as a whole by reason of environmental laws and regulations. Because these

8. Environmental Regulation (Continued)

laws and regulations are constantly being changed, we are unable to predict the conditions and other factors, over which we do not exercise control, that may give rise to environmental liabilities affecting us.

9. Geographic Operating Segment Information and Oil and Natural Gas Disclosures

We have operations in only one industry segment, that being the oil and natural gas exploration and production industry; however, we are organizationally structured along geographic operating segments. We have reportable operations in the United States and Canada. The following tables provide our geographic operating segment data. Operating segment data represents Canadian activity beginning April 26, 2001, when we acquired Addison Energy Inc.

The following table presents total capitalized costs of proved and unproved properties, accumulated depreciation, depletion and amortization related to oil and natural gas production, and total assets:

	United States	Canada	Total
		(In thousands)	
As of December 31, 2000:			
Oil and natural gas properties	$ 90,586	$ —	$ 90,586
Accumulated depreciation, depletion and amortization	(10,231)	—	(10,231)
Oil and natural gas properties, net	$ 80,355	$ —	$ 80,355
Total assets	$ 102,372	$ —	$ 102,372
As of December 31, 2001:			
Oil and natural gas properties	$ 135,306	$ 105,230	$ 240,536
Accumulated depreciation, depletion and amortization	(48,006)	(27,695)	(75,701)
Oil and natural gas properties, net	$ 87,300	$ 77,535	$ 164,835
Total assets	$ 109,682	$ 81,374	$ 191,056
As of December 31, 2002:			
Oil and natural gas properties	$ 165,058	$ 154,438	**$ 319,496**
Accumulated depreciation, depletion and amortization	(56,581)	(52,964)	**(109,545)**
Oil and natural gas properties, net	$ 108,477	$ 101,474	**$ 209,951**
Total assets	$ 130,829	$ 110,345	**$ 241,174**

9. Geographic Operating Segment Information and Oil and Natural Gas Disclosures (Continued)

Presented below are costs incurred in oil and natural gas property acquisition, exploration and development activities:

	United States	Canada	Total
	(In thousands, except per unit amounts)		
2000:			
Property acquisition costs	$ 66,270	$ —	$ 66,270
Development costs	847	—	847
Depreciation, depletion and amortization per Boe	$ 4.18	$ —	$ 4.18
Depreciation, depletion and amortization per Mcfe	$ 0.69	$ —	$ 0.69
2001:			
Property acquisition costs	$ 29,471	$ 84,576	$ 114,047
Development costs	14,977	8,858	23,835
Depreciation, depletion and amortization per Boe	$ 4.82	$ 9.07	$ 5.65
Depreciation, depletion and amortization per Mcfe	$ 0.80	$ 1.50	$ 0.94
2002:			
Property acquisition costs	$ 23,049	$ 32,783	**$ 55,832**
Development costs	10,554	15,468	**26,022**
Depreciation, depletion and amortization per Boe	$ 4.56	$ 5.20	**$ 4.85**
Depreciation, depletion and amortization per Mcfe	$ 0.76	$ 0.87	**$ 0.81**

9. Geographic Operating Segment Information and Oil and Natural Gas Disclosures (Continued)

The results of operations from our oil and natural gas producing activities are as follows:

	United States	Canada	Corporate and Other	Total
		(In thousands)		
Year ended December 31, 2000:				
Oil and natural gas sales	$ 28,869	$ —	$ —	$ 28,869
Other income	—	—	1,790	1,790
	28,869	—	1,790	30,659
Production costs	(9,484)	—	—	(9,484)
Depreciation, depletion and amortization	(4,949)	—	—	(4,949)
General and administrative	—	—	(2,003)	(2,003)
Interest	—	—	(1,369)	(1,369)
	(14,433)	—	(3,372)	(17,805)
Income (loss) before income taxes	14,436	—	(1,582)	12,854
Income tax expense (benefit)	4,908	—	(508)	4,400
Net income (loss)	$ 9,528	$ —	$ (1,074)	$ 8,454
Year ended December 31, 2001:				
Oil and natural gas sales	$ 53,017	$ 8,220	$ —	$ 61,237
Income from derivative ineffectiveness and terminated hedges	4,147	—	—	4,147
Other income	—	—	1,556	1,556
	57,164	8,220	1,556	66,940
Production costs	(21,395)	(2,519)	—	(23,914)
Depreciation, depletion and amortization	(9,743)	(4,501)	—	(14,244)
General and administrative	—	—	(4,806)	(4,806)
Interest	—	—	(3,133)	(3,133)
Impairment of oil and natural gas properties	(28,646)	(20,929)	—	(49,575)
Uncollectible value of Enron hedges	(10,669)	—	—	(10,669)
	(70,453)	(27,949)	(7,939)	(106,341)
Income (loss) before income taxes	(13,289)	(19,729)	(6,383)	(39,401)
Income tax expense (benefit)	(4,518)	(8,799)	13,263	(54)
Net income (loss)	$ (8,771)	$ (10,930)	$ (19,646)	$ (39,347)

9. Geographic Operating Segment Information and Oil and Natural Gas Disclosures (Continued)

	United States	Canada	Corporate and Other	Total
		(In thousands)		
Year ended December 31, 2002:				
Oil and natural gas sales	$ 34,254	$ 32,192	$ —	$ **66,446**
Income from derivative ineffectiveness and terminated hedges	6,090	—	—	**6,090**
Other income	—	—	567	**567**
	40,344	32,192	567	**73,103**
Production costs	(19,020)	(10,203)	—	**(29,223)**
Depreciation, depletion and amortization	(9,529)	(9,029)	—	**(18,558)**
General and administrative	—	—	(10,968)	**(10,968)**
Interest	—	—	(3,408)	**(3,408)**
Impairment of oil and natural gas properties	—	(17,459)	—	**(17,459)**
Impairment of marketable securities	—	—	(1,136)	**(1,136)**
	(28,549)	(36,691)	(15,512)	**(80,752)**
Income (loss) before income taxes	11,795	(4,499)	(14,945)	**(7,649)**
Income tax expense (benefit)	4,010	(2,007)	(8,685)	**(6,682)**
Net income (loss)	$ 7,785	$ (2,492)	$ (6,260)	$ **(967)**

10. Hedging Activities

In connection with the incurrence of debt related to our acquisition activities and to protect against commodity price fluctuations, management has adopted a policy of hedging oil and natural gas prices through the use of commodity futures, options and swap agreements. Effective January 1, 2001, we adopted SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activity," which established accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results from the hedged item on the income statement. Companies must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. For derivatives classified as cash flow hedges, changes in fair value are recognized in other comprehensive income until the hedged item is recognized in earnings. The ineffective portion of any change in the fair value of a derivative designated as a hedge is immediately recognized in earnings. Hedge effectiveness is measured quarterly based on the relative fair value between the derivative contract and the hedged item over time. At adoption, we recognized a net derivative liability and a reduction in other comprehensive income of

10. Hedging Activities (Continued)

approximately $1.1 million as a cumulative effect of an accounting change for all of our cash flow hedges in place at that time.

In accordance with management's policy of hedging oil and natural gas prices, we entered into several swap transactions during 2000, and through September 2001. The counterparty of all of these swap transactions was Enron North America Corp., an affiliate of Enron Corp. (the Enron Hedges). On December 2, 2001, Enron Corp. and other Enron related entities, including Enron North America, filed for bankruptcy under Chapter 11 of the United States Code in the United States Bankruptcy Court in the Southern District of New York. We terminated all of our hedging contracts with Enron North America, effective as of December 5, 2001, as a result of the failure of the Enron affiliate to make payments totaling approximately $2.1 million due us on December 5, 2001, on hedged natural gas volumes and on December 7, 2001, we believe that we are owed approximately $15.3 million, including settlements already due, but the exact amount will be determined pursuant to the terms of the ISDA Master Agreement.

In accordance with the provisions of SFAS No. 133, we had recognized, as of November 30, 2001, a $13.2 million derivative asset on our balance sheet. This amount represented the estimated fair value of the future cash flows to us based upon the market price of oil and natural gas at that date. Due to the complex nature of the Enron bankruptcy proceedings and the extensive litigation involving Enron, we do not expect that we will receive any settlement as a result of the bankruptcies for an extended period of time, if at all; therefore, at December 31, 2001, we classified the Enron derivative asset as an other long-term asset and reduced the asset balance to $2.8 million, which represented our estimate of the fair market value of our bankruptcy claim against Enron North America. As a result, we charged $10.7 million to expense during 2001. Our estimate of the value of our bankruptcy claim is based upon informal offers that we have received from third parties attempting to purchase those claims as well as management's best estimate of the financial condition of Enron's bankruptcy estate as determined from published reports and court filings related to the bankruptcy.

As stated above, we terminated hedge accounting for the Enron Hedges effective as of November 30, 2001. Under the requirements of SFAS No. 133, we are required to reclassify amounts related to the Enron Hedges that remain in other comprehensive income as of the date of the termination into revenue as the oil and natural gas volumes that were hedged are produced. During the years ended December 31, 2001 and 2002, we reclassified approximately $1.3 million and $7.0 million, respectively, related to the Enron Hedges from other comprehensive income to other income. At December 31, 2002, approximately $2.1 million remained in other comprehensive income related to the Enron Hedges and will be reclassified into other income as shown in the following table:

	Amount (In thousands)
During 2003:	
Quarter ending March 31, 2003	$ 976
Quarter ending June 30, 2003	631
Quarter ending September 30, 2003	464
Total amount in 2003	**$ 2,071**

The following table sets forth our oil and natural gas hedges as of December 31, 2002. Our contracts are swap arrangements for the sale of oil and natural gas based upon NYMEX pricing. The

10. Hedging Activities (Continued)

market values at December 31, 2002, are estimated from quotes from the counterparties and represent the amount that we would expect to receive or pay to terminate the contracts at December 31, 2002.

Commodity	Contract Date (1)	Effective Date	Termination Date	Notional Volume/ Range Per Month (2)(3)	Aggregate Volume (2)(3)	Strike Price	Market Value at December 31, 2002 (4)
Natural Gas	3/12/2002	1/1/2003	12/31/2003	455,000 Mmbtus	5,460,000 Mmbtus	$ 3.50	$ (5,858,928)
Natural Gas	12/16/2002	1/1/2003	12/31/2003	321,000 Mmbtus - 420,000 Mmbtus	4,428,000 Mmbtus	$ 4.61(5)	$ 90,258
Oil	4/5/2002	1/1/2003	12/31/2003	40,000 Bbls	480,000 Bbls	$ 22.94	$ (1,893,760)
Oil	9/5/2002	1/1/2003	12/31/2003	22,600 Bbls	271,200 Bbls	$ 25.95	$ (261,730)
Oil	9/5/2002	1/1/2004	12/31/2004	20,000 Bbls	240,000 Bbls	$ 23.96	$ 140,001

(1) The counterparties to these contracts are BNP Paribas and Bank One, financial lending institutions and members of our U.S. and Canadian bank groups.

(2) Bbls—Barrels.

(3) Mmbtus—Million British thermal units.

(4) On December 31, 2002, the average forward NYMEX oil prices for calendar 2003 and 2004 were $26.91 per Bbl and $23.36 per Bbl, respectively, and the average forward NYMEX natural gas price for calendar 2003 was $4.58 per Mmbtu.

(5) Weighted average.

At December 31, 2002, there was a net loss of approximately $7.1 million in other comprehensive income related to our oil and natural gas hedges. Based upon contractual volumes, we expect to reclassify $7.2 million as a reduction of oil and natural gas revenues during 2003.

Oil and natural gas revenues for the years ended December 31, 2000, 2001 and 2002, include a net loss of $1.1 million, a net gain of $6.3 million and a net loss of $7.7 million, respectively, from the settlement of cash flow hedges. For the years ended December 31, 2001 and 2002, other income included a gain of $3.5 million and a loss of $886,000, respectively, from hedge ineffectiveness.

11. Acquisitions and Dispositions

We have accounted for the following acquisitions in accordance with APB No. 16, "Business Combinations" and SFAS 141 where applicable.

Entity	Transactions in 2000	Event Date
EXCO Resources, Inc.	Purchased Val Verde County Properties	February 25, 2000
	Purchased Central Properties	September 22, 2000
Pecos-Gomez, L.P.	Purchased Pecos County Properties	March 24, 2000
Entity	**Transactions in 2001**	**Event Date**
EXCO Resources, Inc.	Purchased STB Energy Properties	March 8, 2001
EXCO Resources, Inc.	Purchased Addison Energy Inc.	April 26, 2001
EXCO Resources, Inc.	Purchased additional interests in Pecos County Properties	July 3, 2001
Addison Energy Inc.	Purchased PrimeWest Properties	December 18, 2001
Entity	**Transactions in 2002**	**Event Date**
Addison Energy Inc.	Purchased Medicine River Properties	April 29, 2002
EXCO Resources, Inc.	Purchased DJ Basin Properties	November 1, 2002

Significant transactions which closed during 2001 are more fully described below.

STB Energy Properties Acquisition.

On March 8, 2001, we acquired from STB Energy, Inc. oil and natural gas properties located in Louisiana, Oklahoma, Texas and Nebraska. As of January 1, 2001, estimated total proved reserves net to our interest included approximately 694,000 Bbls of oil and 9.5 Bcf of natural gas from 125 gross (78.3 net) wells. The purchase price consisted of $15.0 million in cash ($14.8 million after contractual adjustments).

Addison Energy Inc. Acquisition.

On April 26, 2001, we acquired all of the outstanding common stock of Addison Energy Inc. (Addison), which is headquartered in Calgary, Alberta, Canada. At the date of acquisition, Addison owned interests in 95 gross (85.03 net) wells located in Alberta and Addison operated 91 of these wells. The Addison properties included approximately 27,672 gross and 23,994 net developed acres and approximately 38,947 gross and 28,795 net undeveloped acres. As of January 1, 2001, estimated total proved reserves net to our interest acquired in this acquisition included approximately 2.1 million Bbls of oil and NGLs and 36.9 Bcf of natural gas. After adjustments for working capital and long-term debt, we paid approximately $44.4 million (CDN $68.5 million) for Addison. We paid the adjusted purchase price from the proceeds of borrowings under our new U.S. and Canadian credit agreements. The price was determined through arms-length negotiation between the parties.

Pecos County Properties Acquisitions.

On March 24, 2000, Pecos-Gomez, L.P. (previously known as Humphrey-Hill, L.P.) (the Partnership) acquired 8 gross (4.25 net) producing wells in Pecos County, Texas for $10.2 million. As of January 1, 2000, the acquired properties were estimated to contain total proved reserves of 25.1 Bcf of natural gas. At the time of the acquisition, EXCO was the general partner of the Partnership and

11. Acquisitions and Dispositions (Continued)

owned a 1% interest in the Partnership as the general partner and a 50% interest as a limited partner. The acquisition price was partially funded from the proceeds of a credit facility established by the Partnership with Bank of America, N.A. On May 16, 2000, EXCO acquired an additional 4.1% limited partnership interest in the Partnership. On July 3, 2001, the Partnership conveyed all of its oil and natural gas property interests to its partners and began the process to dissolve the Partnership. Also on July 3, 2001, EXCO acquired additional interests in the properties from two of the limited partners for $8.8 million (approximately $7.5 million after contractual adjustments). In addition, EXCO received an assignment of the existing Partnership hedge contract. Borrowings under the Partnership credit facility of $3.9 million were also repaid at the time of the acquisition and the credit facility was canceled.

PrimeWest Properties Acquisition.

On December 18, 2001, Addison, our Canadian subsidiary, acquired oil and natural gas properties located in Alberta, Canada. As of December 31, 2001, total proved reserves net to our interest included approximately 3.6 million barrels of oil and NGLs, and 27.1 Bcf of natural gas. Estimated daily production, net to our interest, in December 2001, was approximately 600 barrels of oil and NGLs, and 4,100 Mcf of natural gas from the acquired properties. The effective date of this transaction was December 18, 2001. The purchase price was approximately $33.8 million or CDN $53.6 million cash ($33.6 million or CDN $53.3 million after contractual adjustments), funded with borrowings under our Canadian credit agreement.

Significant transactions which closed during 2002 are more fully described below.

Medicine River Properties Acquisition.

On April 29, 2002, Addison acquired oil and natural gas properties located in the Medicine River, Garrington, Gull Lake and Sylvan Lake areas in Alberta, Canada. The effective date of this transaction was January 1, 2002. As of January 1, 2002, estimated total proved reserves net to our interest included approximately 1.6 million Bbls of oil and NGLs, and 19.5 Bcf of natural gas. The purchase price was approximately $25.8 million or CDN $40.5 million ($24.7 million or CDN $36.3 million after contractual adjustments), funded with borrowings under our U.S. and Canadian credit agreements.

DJ Basin Properties Acquisition.

On November 1, 2002, we acquired oil and natural gas properties located in the DJ Basin in Colorado. As of October 1, 2002, estimated total proved reserves net to our interest included approximately 2.1 Mmbbls of oil and NGLs, and 13.5 Bcf of natural gas from 111 gross (103 net) wells. Net daily production in September 2002, was approximately 630 Bbls of oil and NGLs, and 3.7 Mmcf of natural gas. The purchase price was approximately $22.0 million cash ($21.1 million after contractual adjustments), funded with $19.7 million of bank debt from our U.S. credit agreement and $1.4 million from surplus cash.

Pro Forma Results of Operations.

The following reflects the pro forma results of operations as though the acquisition of the STB Energy Properties, Addison Energy Inc., and the PrimeWest Properties, the related borrowings and our

11. Acquisitions and Dispositions (Continued)

5% convertible preferred stock offering had been consummated on January 1, 2001. The remaining acquisitions were all less than 20% of our total assets when purchased.

	Year Ended December 31,	
	2001	2002
	(In thousands, except per share data) (Unaudited)	
Revenues	$ 86,008	$ **73,103**
Earnings (loss) on common stock	$ (38,077)	$ **(6,223)**
Income (loss) per share before extraordinary item:		
Basic	$ (5.29)	$ **(0.88)**
Diluted	$ (5.29)	$ **(0.88)**

12. Concentration of Credit Risk

During 2002, sales of oil to Plains All American, Inc. and affiliates and sales of natural gas to Engage Energy America, LLC accounted for 21.6% and 14.5%, respectively, of our total oil and natural gas revenues. If we were to lose any one of our oil and natural gas purchasers, the loss could temporarily cease or delay production and sale of our oil and natural gas in that particular purchaser's service area. If we were to lose a purchaser, we believe we could identify a substitute purchaser. During 2002, several large wholesale purchasers of natural gas experienced significant downgrades in their credit ratings. As a result, many of these companies have either significantly reduced their level of natural gas purchases or have discontinued their purchases of natural gas. Although, we do not believe that we have yet been significantly impacted by these changes, the loss of these large natural gas purchasers could have a detrimental effect on the natural gas market in general and on our ability to find purchasers for our natural gas.

During 2001, sales of oil to Plains All American, Inc. and affiliates, and sales of natural gas to Western Gas Resources, Inc. accounted for 14.5% and 11.8%, respectively, of our total oil and natural gas revenues. During 2000, sales of oil and natural gas to three purchasers, Western Gas Resources, Inc., Plains All American, Inc. and Oneok Gas Marketing, LLC accounted for 23.6%, 19.9% and 11.9%, respectively, of our total oil and natural gas revenues.

13. Acquisition Proposal

We announced on August 7, 2002, that our Chairman and Chief Executive Officer, Douglas H. Miller, made an offer to purchase all of the outstanding shares of our stock not already owned by Mr. Miller. Mr. Miller currently owns approximately 8.2% of our outstanding common stock and 1.8% of our outstanding 5% convertible preferred stock.

Under the terms of that offer, the holders of our outstanding shares of common stock would have received $17.00 per share in cash. The holders of our outstanding 5% convertible preferred stock would have received between $17.00 and $18.05 per share in cash depending upon the closing date of the acquisition transaction, which price we were advised took into account the remaining stated dividends at the time the offer was made and the mandatory conversion of the 5% convertible preferred stock on June 30, 2003.

Our board of directors established a special committee comprised of J. Michael Muckleroy and Stephen F. Smith to consider the proposal, and to evaluate, negotiate and make a recommendation to

13. Acquisition Proposal (Continued)

our full board on the proposal. The special committee retained Bracewell & Patterson, L.L.P. as its legal advisor and Merrill Lynch & Co. as its financial advisor to assist it in evaluating the proposal from Mr. Miller and other proposals it receives. The proposal from Mr. Miller was made subject to the negotiation and execution of a definitive acquisition agreement containing mutually agreeable terms and conditions as are customary in such agreements, including but not limited to customary representations, warranties, covenants and conditions. It was also subject to, among other things, (1) the approval of the transaction by the special committee, our board of directors and our shareholders, (2) receipt of satisfactory financing for the transaction, (3) receipt of a fairness opinion by the special committee, and (4) the receipt of all necessary regulatory approvals.

On August 7, 2002, litigation was filed in connection with Mr. Miller's proposed offer. The litigation was filed in the 160th State District Court in Dallas County, Texas, and is captioned *Weiser v. EXCO Resources, Inc. et al.*, Cause No. 02-7065. The complaint was purportedly filed on behalf of our public shareholders and alleges that our current directors breached fiduciary duties owed to our shareholders in connection with Mr. Miller's offer. We are named as a defendant in the litigation. The litigation seeks declaratory and injunctive relief to enjoin our ability to engage in such a transaction with Mr. Miller and the recovery of any compensatory damages that would allegedly be sustained as a result of the transaction. We believe that the allegations contained in the complaint are without merit, and plan to vigorously contest and defend against the litigation.

On August 12, 2002, litigation was filed in the 162nd State District Court in Dallas County, Texas, and is captioned *Birnbaum v. EXCO Resources, Inc., et al,* Cause No. 02-07396-I. The complaint was purportedly filed on behalf of our public shareholders and alleges that our current directors breached fiduciary duties owed to our shareholders in connection with Mr. Miller's offer. We are named as a defendant in the litigation. The litigation seeks declaratory and injunctive relief to enjoin our ability to engage in such a transaction with Mr. Miller and the recovery of any compensatory damages that would allegedly be sustained as a result of the transaction. We believe that the allegations contained in the complaint are without merit, and plan to vigorously contest and defend against the litigation.

On October 25, 2002, the *Weiser and Birnbaum* cases were consolidated in the 160th District Court. The proceedings have been stayed by the agreement of the parties until Mr. Miller files an offer to purchase us with the SEC or until the setting of a shareholder meeting to approve a merger.

On December 30, 2002, we announced that we had received a revised proposal for the acquisition of the company by Mr. Miller and his group. The revised proposal increased the consideration for the common stock to $18.00 per share and the consideration for the 5% convertible preferred stock to between $18.00 per share and $18.525 per share, depending upon the date of the closing. The revised proposal took into account the remaining stated dividends at the time the offer was made and the mandatory conversion of the 5% convertible preferred stock on June 30, 2003.

14. Subsequent Event

On March 11, 2003, the special committee recommended approval, our board of directors resolved to submit to our shareholders, and we entered into an Agreement and Plan of Merger providing for the merger of ER Acquisitions, Inc., a Texas corporation, and a wholly-owned subsidiary of EXCO Holdings Inc., a Delaware corporation, into EXCO. Following the completion of the merger, ER Acquisitions, Inc. will cease to exist as a separate entity, and EXCO will continue as the surviving corporation of the merger and as a wholly-owned subsidiary of EXCO Holdings, Inc. Upon consummation of the merger transaction, our common stock and 5% convertible preferred stock could

14. Subsequent Event (Continued)

be delisted from trading on the NASDAQ National Market or any other exchange and the common stock and the 5% convertible preferred stock could become eligible for termination of registration pursuant to Secion 12(g)(4) of the Securities Exchange Act of 1934.

15. Supplemental Oil and Natural Gas Reserves and Standardized Measure Information (Unaudited)

We retain independent engineering firms to provide annual year-end estimates of our future net recoverable oil, natural gas and NGL reserves. The estimated proved net recoverable reserves we show below include only those quantities that we expect to be commercially recoverable at prices and costs in effect at the balance sheet dates under existing regulatory practices and with conventional equipment and operating methods. Proved developed reserves represent only those reserves that we may recover through existing wells. Proved undeveloped reserves include those reserves that we may recover from new wells on undrilled acreage or from existing wells on which we must make a relatively major expenditure for recompletion or secondary recovery operations.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of our oil and natural gas properties. Estimates of fair value should also consider probable reserves, anticipated future oil and natural gas prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is subjective and imprecise.

15. Supplemental Oil and Natural Gas Reserves and Standardized Measure Information (Unaudited) (Continued)

Estimated Quantities of Proved Reserves

	United States			Canada			Total			
	Oil (Bbls)	Natural Gas (Mcf)	NGLs (Bbls)	Oil (Bbls)	Natural Gas (Mcf)	NGLs (Bbls)	Oil (Bbls)	Natural Gas (Mcf)	NGLs (Bbls)	Mcfe(1)
					(In thousands)					
December 31, 1999	2,744	16,548	370	—	—	—	2,744	16,548	370	35,232
Purchase of reserves in place	10,043	80,279	126	—	—	—	10,043	80,279	126	141,293
New discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Revisions of previous estimates	93	2,543	112	—	—	—	93	2,543	112	3,773
Production	(433)	(3,982)	(89)	—	—	—	(433)	(3,982)	(89)	(7,114)
Sales of reserves in place	(69)	(944)	(54)	—	—	—	(69)	(944)	(54)	(1,682)
December 31, 2000	12,378	94,444	465	—	—	—	12,378	94,444	465	171,502
Purchase of reserves in place	809	23,463	329	3,137	63,901	2,539	3,946	87,364	2,868	128,248
New discoveries and extensions	79	72	—	318	4,611	198	397	4,683	198	8,253
Revisions of previous estimates	(1,200)	(956)	98	425	6,978	160	(775)	6,022	258	2,920
Production	(887)	(6,243)	(96)	(80)	(2,086)	(68)	(967)	(8,329)	(164)	(15,115)
Sales of reserves in place	(126)	(524)	(9)	—	—	—	(126)	(524)	(9)	(1,334)
December 31, 2001	11,053	110,256	787	3,800	73,404	2,829	14,853	183,660	3,616	294,474
Purchase of reserves in place	1,781	18,844	—	1,201	25,839	1,002	2,982	44,683	1,002	68,587
New discoveries and extensions	339	7,774	105	323	17,867	643	662	25,641	748	34,101
Revisions of previous estimates	502	12,777	299	829	(2,850)	(238)	1,331	9,927	61	18,279
Production	(869)	(6,878)	(74)	(399)	(6,565)	(242)	(1,268)	(13,443)	(316)	(22,947)
Sales of reserves in place	(525)	(1,175)	(20)	—	—	—	(525)	(1,175)	(20)	(4,445)
December 31, 2002	**12,281**	**141,598**	**1,097**	**5,754**	**107,695**	**3,994**	**18,035**	**249,293**	**5,091**	**388,049**

Estimated Quantities of Proved Developed Reserves

	United States			Canada			Total			
	Oil (Bbls)	Natural Gas (Mcf)	NGLs (Bbls)	Oil (Bbls)	Natural Gas (Mcf)	NGLs (Bbls)	Oil (Bbls)	Natural Gas (Mcf)	NGLs (Bbls)	Mcfe(1)
					(In thousands)					
December 31, 2000	8,148	66,497	465	—	—	—	8,148	66,497	465	118,175
December 31, 2001	7,555	87,868	774	3,414	65,230	2,470	10,969	153,098	3,244	238,376
December 31, 2002	**9,067**	**115,222**	**985**	**5,425**	**92,512**	**3,432**	**14,492**	**207,734**	**4,417**	**321,188**

(1) Mcfe—Thousand cubic feet equivalent by converting 1 Bbl of oil to 6 Mcf of natural gas.

15. Supplemental Oil and Natural Gas Reserves and Standardized Measure Information (Unaudited) (Continued)

Standardized Measure of Discounted Future Net Cash Flows

We have summarized the standardized measure of discounted net cash flows related to our proved oil, natural gas, and NGL reserves. We have based the following summary on a valuation of proved reserves using discounted cash flows based on year-end prices, costs and economic conditions and a 10% discount rate. The additions to proved reserves from the purchase of reserves in place, and new discoveries and extensions could vary significantly from year to year; additionally, the impact of changes to reflect current prices and costs of reserves proved in prior years could also be significant. Accordingly, you should not view the information presented below as an estimate of the fair value of our oil and natural gas properties, nor should you consider the information indicative of any trends.

	United States	Canada (In thousands)	Total
Year ended December 31, 2000:			
Future cash inflows	$ 1,192,705	$ —	$ 1,192,705
Future production and development costs	344,013	—	344,013
Future income taxes	274,899	—	274,899
Future net cash flows	573,793	—	573,793
Discount of future net cash flows at 10% per annum	291,357	—	291,357
Standardized measure of discounted future net cash flows	$ 282,436	$ —	$ 282,436
Year ended December 31, 2001:			
Future cash inflows	$ 453,313	$ 280,001	$ 733,314
Future production and development costs	225,167	122,212	347,379
Future income taxes	41,855	47,345	89,200
Future net cash flows	186,291	110,444	296,735
Discount of future net cash flows at 10% per annum	103,206	50,000	153,206
Standardized measure of discounted future net cash flows	$ 83,085	$ 60,444	$ 143,529
Year ended December 31, 2002:			
Future cash inflows	$ 997,524	$ 683,969	**$ 1,681,493**
Future production and development costs	375,879	223,372	**599,251**
Future income taxes	294,387	175,700	**470,087**
Future net cash flows	327,258	284,897	**612,155**
Discount of future net cash flows at 10% per annum	174,335	127,480	**301,815**
Standardized measure of discounted future net cash flows	$ 152,923	$ 157,417	**$ 310,340**

At December 31, 2002, the present value of our future net cash flows before income taxes discounted at 10% was approximately $530.0 million.

During recent years, prices paid for oil and natural gas have fluctuated significantly. The prices of oil, natural gas and NGLs at December 31, 2000, 2001 and 2002 used in the above table, were $24.82, $17.76 and $29.56 per Bbl of oil, respectively, $9.26, $2.23 and $4.12 per Mcf of natural gas, respectively, and $21.50, $15.09 and $21.96 per Bbl of NGLs, respectively.

15. Supplemental Oil and Natural Gas Reserves and Standardized Measure Information (Unaudited) (Continued)

Changes in Standardized Measure

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

	United States	Canada	Total
		(In thousands)	
Year ended December 31, 2000:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (20,526)	$ —	$ (20,526)
Net changes in prices and production costs	233,572	—	233,572
Extensions and discoveries, net of future development and production costs	—	—	—
Development costs during the period	352	—	352
Changes in estimated future development costs	550	—	550
Revisions of previous quantity estimates	9,880	—	9,880
Sales of reserves in place	(4,740)	—	(4,740)
Purchases of reserves in place	155,648	—	155,648
Accretion of discount before income taxes	3,595	—	3,595
Net change in income taxes	(124,490)	—	(124,490)
Net change	$ 253,841	$ —	$ 253,841
Year ended December 31, 2001:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (25,348)	$ (5,701)	$ (31,049)
Net changes in prices and production costs	(344,892)	(54,809)	(399,701)
Extensions and discoveries, net of future development and production costs	607	6,112	6,719
Development costs during the period	8,340	8,858	17,198
Changes in estimated future development costs	4,356	—	4,356
Revisions of previous quantity estimates	(6,499)	6,836	337
Sales of reserves in place	(1,062)	—	(1,062)
Purchases of reserves in place	41,547	114,120	155,667
Accretion of discount before income taxes	10,147	8,380	18,527
Net change in income taxes	113,453	(23,352)	90,101
Net change	$ (199,351)	$ 60,444	$ (138,907)
Year ended December 31, 2002:			
Sales and transfers of oil and natural gas produced, net of production costs	$ (22,971)	$ (21,954)	**$ (44,925)**
Net changes in prices and production costs	90,164	31,336	**121,500**
Extensions and discoveries, net of future development and production costs	23,415	35,888	**59,303**
Development costs during the period	7,063	16,121	**23,184**
Changes in estimated future development costs	2,979	24,281	**27,260**
Revisions of previous quantity estimates	25,806	981	**26,787**
Sales of reserves in place	(1,705)	—	**(1,705)**
Purchases of reserves in place	29,228	50,908	**80,136**
Accretion of discount before income taxes	28,384	24,595	**52,979**
Net change in income taxes	(112,525)	(65,183)	**(177,708)**
Net change	$ 69,838	$ 96,973	**$ 166,811**

16. Selected Quarterly Financial Information (Unaudited)

	2002			
	March 31	June 30	September 30	December 31
	(In thousands, except per share amounts)			
Total revenues	$ 14,648	$ 17,128	$ 17,701	$ 23,626
Earnings (loss) on common stock	752	(9,117)	(510)	2,652
Basic earnings (loss) per share	0.10	(1.28)	(0.07)	0.37
Diluted income (loss) per share	0.10	(1.28)	(0.07)	0.37
Total assets	198,033	214,764	210,874	241,174
Long-term debt, less current maturities	51,945	84,865	80,235	97,943
Stockholders' equity	111,076	100,815	95,482	99,884

	2001			
	March 31	June 30	September 30	December 31
	(In thousands, except per share amounts)			
Total revenues	$ 13,663	$ 17,870	$ 18,032	$ 17,375
Impairment of oil and natural gas properties	—	—	45,942	3,633
Uncollectible value of Enron hedges	—	—	—	10,669
Earnings (loss) on common stock	2,962	2,821	(38,819)	(8,964)
Basic earnings (loss) per share	0.43	0.40	(5.41)	(1.25)
Diluted income (loss) per share	0.40	0.37	(5.41)	(1.25)
Total assets	121,421	224,240	166,885	191,056
Long-term debt, less current maturities	56,157	2,151	1,361	44,994
Stockholders' equity	54,137	170,822	133,370	120,379

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

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Directors and Executive Officers

Douglas H. Miller, 55, became our Chairman and Chief Executive Officer in December 1997. Mr. Miller was Chairman of the Board and Chief Executive Officer of Coda Energy, Inc., an independent oil and natural gas company, from October 1989 until November 1997 and served as a director of Coda from 1987 until November 1997.

T. W. Eubank, 60, became our President, Treasurer and a director in December 1997. Mr. Eubank was a consultant to various private companies from February 1996 to December 1997. Mr. Eubank served as President of Coda from March 1985 until February 1996. He was a director of Coda from 1981 until February 1996.

J. Douglas Ramsey, Ph.D., 42, became our Chief Financial Officer and a Vice President in December 1997. Dr. Ramsey has been one of our directors since March 1998. Dr. Ramsey most recently was Financial Planning Manager of Coda and worked in various capacities for Coda from 1992 until 1997. Dr. Ramsey also taught finance at Southern Methodist University.

Jeffrey D. Benjamin, 41, has been one of our directors since August 1998. Mr. Benjamin has been a Senior Advisor to Apollo Management, LP since September 2002. He had previously been a Managing Director of Libra Securities LLC, an investment banking firm since January 2002 and served in various capacities, including Co-Chief Executive Officer of Libra Securities and its predecessors since May 1998. From May 1996 to May 1998, Mr. Benjamin was Managing Director at UBS Securities LLC, an investment banking firm. Mr. Benjamin is also a Director of McLeod USA Incorporated, Dade Behring Holdings Inc., Chiquita Brands International, Inc. and NTL Incorporated.

Earl E. Ellis, 61, has been one of our directors since March 1998. Mr. Ellis is currently a private investor. He served as a Director of Coda from 1992 until 1996. Mr. Ellis served as a managing partner of Benjamin Jacobson & Sons, LLC, specialists on the New York Stock Exchange. He had been associated with Benjamin Jacobson & Sons, LLC from 1977 to 2001.

J. Michael Muckleroy, 72, has been one of our directors since March 1998. He is currently an independent oil and gas producer and acts as manager of his family's stock portfolios. Mr. Muckleroy served as President of Houston Natural Gas Liquids from 1984 until the end of 1985. From 1985 until his retirement in 1993, Mr. Muckleroy served as Chairman and Chief Executive Officer of Enron Liquid Fuels.

Boone Pickens, 74, has been one of our directors since March 1998. Mr. Pickens is currently the Chairman and CEO of BP Capital LP and Mesa Water, Inc. and is a board member of ENRG. BP Capital LP or affiliates is the general partner and an investment advisor of private funds investing in energy commodities (BP Capital Energy Fund) and publically-traded energy equities (BP Capital Equity Fund and its offshore counterpart). ENRG is the largest provider of natural gas (CNG and LNG) and related services in North America. He was the founder of Mesa Petroleum Co., an independent oil and natural gas exploration and production company. He served as CEO and Chairman of the Board of Mesa from its inception until his departure in 1996.

Stephen F. Smith, 61, has been one of our directors since March 1998. From 1980 to present, Mr. Smith has been co-founder and Executive Vice President of Sandefer Oil and Gas, Inc., an independent oil and gas exploration and production company. Prior to 1980, Mr. Smith was an Audit Partner with Arthur Andersen LLP.

Charles R. Evans, 49, joined us in February 1998, became a Vice President in March 1998, and was named our Chief Operating Officer in December 2000. Mr. Evans graduated from Oklahoma University with a B.S. degree in Petroleum Engineering in 1976. After working for Sun Oil Co., he joined TXO Production Corp. in 1979 and was appointed Vice President of Engineering and Evaluation in 1989. In 1990, he was named Vice President of Engineering and Project Development for Delhi Gas Pipeline Corporation, a natural gas gathering, processing and marketing company. Mr. Evans served as Director—Environmental Affairs and Safety for Delhi until December 1997.

Richard E. Miller, 49, became our General Counsel, General Land Manager and Secretary of EXCO in December 1997 and became a Vice President in July 2000. Mr. Miller was a senior partner and head of the Energy Section of Gardere & Wynne, L.L.P., a Dallas based law firm, from December 1991 to September 1994. Mr. Miller practiced law as a sole practitioner from September 1994 to December 1997.

J. David Choisser, CPA, 52, joined us in October 2001 and became our Chief Accounting Officer in November 2001, and a Vice President in February 2002. He began his career in 1972 with Deloitte Haskins & Sells (now Deloitte & Touche). During the past 25 years, he has served in various financial and accounting management capacities with several energy and energy-related companies, including Delhi Gas Pipeline Corporation, Coda Energy, Inc., Belco Oil & Gas Corp., and The Meridian Resource Corporation. He most recently served as Vice President—Finance of Noble Denton & Associates, Inc., an offshore engineering and marine consulting company.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires the company's executive officers, directors and persons who own more than 10% of the company's stock to file reports with the Securities and Exchange Commission and to provide us with copies of ownership and changes in ownership. The SEC regulations require the company to identify anyone who filed a required report after the filing deadline during the most recent fiscal year. Based upon a review of our records, we believe that all 2002 filing requirements were timely met.

ITEM 11. EXECUTIVE COMPENSATION

Summary Compensation Table

The following table provides compensation information for the fiscal years 2000, 2001 and 2002 for the company's Chief Executive Officer, Douglas H. Miller, and the four most highly compensated executive officers other than Mr. D. H. Miller: T. W. Eubank, J. Douglas Ramsey, Richard E. Miller and Charles R. Evans.

		Annual Compensation			Long-Term Compensation Awards	
Name and Principal Position	Fiscal Year	Salary	Bonus	Other Annual Compensation	Common Stock Underlying Options	All Other Compensation
		($)	($)	($)	(# of shares)	($)(1)
Douglas H. Miller	2002	$ 300,000	$ 30,000	$ —	—	$ 9,600
Chairman and Chief	2001	$ 300,000	$ 30,000	$ —	30,000	$ 6,300
Executive Officer	2000	$ 100,000	$ 20,000	$ —	10,000	$ 4,200
T. W. Eubank	2002	$ 200,000	$ 20,000	$ —	—	$ 8,800
President and Treasurer	2001	$ 200,000	$ 20,000	$ —	20,000	$ 6,300
	2000	$ 100,000	$ 20,000	$ —	10,000	$ 4,000
J. Douglas Ramsey	2002	$ 150,000	$ 15,000	$ —	—	$ 8,800
Vice President and Chief	2001	$ 150,000	$ 15,000	$ —	15,000	$ 6,300
Financial Officer	2000	$ 100,000	$ 20,000	$ —	10,000	$ 4,200
Richard E. Miller	2002	$ 150,000	$ 15,000	$ —	—	$ 8,800
Vice President, Secretary	2001	$ 150,000	$ 15,000	$ —	15,000	$ 6,300
and General Counsel	2000	$ 125,000	$ 25,000	$ —	12,500	$ 4,200
Charles R. Evans	2002	$ 150,000	$ 15,000	$ —	—	$ 8,800
Vice President and Chief	2001	$ 150,000	$ 15,000	$ —	15,000	$ 6,300
Operating Officer	2000	$ 100,000	$ 20,000	$ —	10,000	$ 4,200

(1) Includes the company's matching contributions under the company's 401(k) plan.

The compensation described in this table does not include medical, group life insurance or other benefits that are available generally to all of the company's salaried employees. It also does not include certain perquisites and other personal benefits, securities or property received by these executive officers that are not material in amount.

Option Grants of Common Stock in Fiscal 2002

	Individual Grants				
Name	Number of Securities Underlying Options Granted	% of Total Options Granted To Employees in Fiscal Year	Exercise Price Per Share	Expiration Date	Grant Date Present Value
Douglas H. Miller	—	—	N/A	N/A	N/A
T. W. Eubank	—	—	N/A	N/A	N/A
J. Douglas Ramsey	—	—	N/A	N/A	N/A
Richard E. Miller	—	—	N/A	N/A	N/A
Charles R. Evans	—	—	N/A	N/A	N/A

Option Exercises in Fiscal Year 2002 and Value at Fiscal Year End 2002

The following table shows the number of shares of common stock covered by both exercisable and non-exercisable stock options held by Messrs. D. H. Miller, Eubank, Ramsey, R. E. Miller, and Evans as of December 31, 2002. This table also shows the value on that date of their "in-the-money" common stock options, which is the positive spread, if any, between the exercise price of existing stock options and $17.48 per share (the closing market price of the common stock on December 31, 2002).

Name	Shares Acquired on Exercise (#)	Value Realized (Loss) ($)	Number of Securities Underlying Unexercised Options at Fiscal Year-End (#)		Value of Unexercised In-the-Money Options at Fiscal Year-End ($)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Douglas H. Miller	—	—	190,000	17,500	$ 1,998,388	$ 65,588
T. W. Eubank	—	—	110,000	12,500	$ 1,117,488	$ 45,688
J. Douglas Ramsey	—	—	107,500	10,000	$ 1,106,913	$ 35,738
Richard E. Miller	—	—	58,021	10,625	$ 521,784	$ 37,209
Charles R. Evans	—	—	73,487	10,000	$ 716,822	$ 35,738

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED SHAREHOLDER MATTERS

This section contains shareholder information for persons known to us to be large shareholders (5% or more of our common or 5% convertible preferred stock), directors or executive officers of EXCO.

Ownership of our common and 5% convertible preferred stock is shown in terms of "beneficial ownership." A person generally "beneficially owns" shares if he has the right to either vote those shares or dispose of them. More than one person may be considered to beneficially own the same shares.

In this report, unless otherwise noted, a person has sole voting and dispositive power for those shares shown as beneficially owned by him. Shares shown as beneficially owned by our executive officers include shares that they have the right to acquire by exercising options on or before May 31, 2003. The percentages shown in this annual report compare the person's beneficially owned shares of common stock plus shares of 5% convertible preferred stock owned by that person on February 28, 2003, plus shares of common stock that can be acquired by that person from exercising options on or before May 31, 2003, plus shares of 5% convertible preferred stock owned by that person on February 28, 2003, with the total number of shares of common stock outstanding on February 28, 2003 (7,277,952 shares of common stock) plus shares of common stock that can be acquired by that person from exercising options on or before May 31, 2003, plus shares of 5% convertible preferred stock owned by that person on February 28, 2003. Also shown is the percentage of 5% convertible preferred stock owned by our executive officers on February 28, 2003, compared with the total number of shares of 5% convertible preferred stock outstanding on February 28, 2003 (4,989,869 shares of 5% convertible preferred stock). There are no outstanding options to purchase our 5% convertible preferred stock. Please note that the 5% convertible preferred stock is immediately convertible into shares of common stock.

Certain Shareholders

The following table shows the beneficial ownership of our common stock and 5% convertible preferred stock as of February 28, 2003, for persons known by us, either through SEC filings or information provided to us, to own five percent or more of our common stock or 5% convertible preferred stock. In the case of Douglas H. Miller, the shares of common stock beneficially owned in the following table also shows beneficial ownership of shares of common stock that he can acquire by exercising options on or before May 31, 2003, plus shares of 5% convertible preferred stock owned by him.

Name and Address	Shares of Common Stock Beneficially Owned		Shares of 5% Convertible Preferred Stock Beneficially Owned	
	Number	Percent	Number	Percent
Ares Leveraged Investment Fund, L.P. Ares Leveraged Investment Fund II, L.P. 1999 Avenue of the Stars, #1900 Los Angeles, California 90067	867,491(1)	11.9%(1)	325,000	6.5%
Stephen Feinberg, as investment manager of Cerberus Capital Management, L.P. 450 Park Avenue New York, New York 10022	1,122,323	15.4%	—	—
FleetBoston Financial Corporation 100 Federal Street Boston, Massachusetts 02110	399,310(2)	5.5%(2)	274,190	5.5%
Lord, Abbett & Co. 90 Hudson Street Jersey City, NJ 07302	865,120	11.9%	—	—
Putnam Investment Management, LLC The Putnam Advisory Company, LLC One Post Office Square Boston, Massachusetts 02109	1,058,257	14.5%	—	—
Douglas H. Miller group (6) EXCO Resources, Inc. 6500 Greenville Avenue, Suite 600, LB 17 Dallas, Texas 75206	2,352,258(5)	28.0%(5)	142,385	2.9%
Mellon Financial Corporation Mellon Bank, N.A. The Dreyfus Corporation One Mellon Center Pittsburgh, Pennsylvania 15258	—	—	714,285	14.3%
Marvin Mermelstein 2955 West Morse Chicago, Illinois 60645	719,094(3)	9.9%(3)	300,000	6.0%
Henry Mermelstein 7141 North Kedzie Chicago, Illinois 60645	399,188(4)	5.5%(4)	397,188	8.0%

(1) Includes 325,000 shares of common stock that may be acquired upon conversion of the 5% convertible preferred stock.

(2) Includes 274,190 shares of common stock that may be acquired upon conversion of the 5% convertible preferred stock.

(3) Includes 300,000 shares of common stock that may be acquired upon conversion of the 5% convertible preferred stock.

(4) Includes 397,188 shares of common stock that may be acquired upon conversion of the 5% convertible preferred stock.

(5) Includes 91,788 shares of common stock that may be acquired upon conversion of the 5% convertible preferred stock and 190,000 options to purchase shares of common stock that will be exercisable upon the closing of the merger.

(6) Includes shares owned by the following members of a Schedule 13D group: Douglas H. Miller—859,122 shares, including 190,000 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days and 91,788 shares of common stock that may be acquired upon the conversion of our 5% convertible preferred stock; T.W. Eubank—263,407 shares, including 110,000 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days and 9,044 shares of common stock that may be acquired upon the conversion of our 5% convertible preferred stock; J. Douglas Ramsey—179,586 shares, including 107,500 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days and 2,087 shares of common stock that may be acquired upon the conversion of our 5% convertible preferred stock; Jeffrey D. Benjamin—118,230 shares, including 50,000 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days and 10,000 shares of common stock that may be acquired upon the conversion of our 5% convertible preferred stock; Earl E. Ellis—322,829 shares, including 25,000 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days and 26,000 shares of common stock that may be acquired upon the conversion of our 5% convertible preferred stock; Charles R. Evans—85,934 shares, including 73,487 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days and 436 shares of common stock that may be acquired upon the conversion of our 5% convertible preferred stock; Richard E. Miller—72,016 shares, including 58,021 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days and 1,035 shares of common stock that may be acquired upon the conversion of our 5% convertible preferred stock; J. David Choisser—8,006 shares, including 7,812 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; James M. Perkins, Jr.—5,451 shares, including 5,000 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days and 451 shares of common stock that may be acquired upon the conversion of our 5% convertible preferred stock; Richard L. Hodges—16,784 shares, including 12,925 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; John D. Jacobi—94,069 shares, including 75,222 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; Daniel A. Johnson—81,592 shares, including 80,222 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; Harold L. Hickey—12,648 shares, including 12,084 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days and 44 shares of common stock that may be acquired upon the conversion of our 5% convertible preferred stock; Stephen E. Puckett—20,162 shares, including 18,662 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days and 1,500 shares of common stock that may be acquired upon the conversion of our 5% convertible preferred stock; Russell W. Romoser—13,764 shares, including 13,250 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; W. Andy Bracken—25,498 shares, including 13,138 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; Paul B. Rudnicki—6,143 shares, including 5,981 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; Gary M. Nelson—23,235 shares, including 21,792 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; Craig F. Hruska—28,882 shares,

including 11,182 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; Steve Fagan—23,572 shares, including 11,182 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; Dennis G. McIntyre—23,632 shares, including 11,182 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; Gregory Robb—18,682 shares, including 11,182 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; Jonathan Kuhn—4,400 shares, including 4,200 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; Jamie Beninger—3,858 shares, including 3,858 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; Terry Pidkowa—5,132 shares, including 5,132 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; Duane Masse—2,540 shares, including 2,540 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; Jennifer M. Perry—1,462 shares, including 1,462 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; Kirstie M. Egan—4,726 shares, including 4,726 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; Wesley E. Roberts—3,026 shares, including 3,026 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; Delwyn C. Dennison—3,620 shares, including 3,620 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; Muharem Mastalic—4,144 shares, including 4,144 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; H. Wayne Gifford—2,500 shares, including 2,500 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; Gary L. Parker—13,606 shares, including 13,158 shares of common stock that may be acquired upon the exercise of options exercisable within 60 days; Terry Trudeau—0 shares; and Neil Burrows—0 shares.

The following table contains shareholder information for our directors, our executive officers, and our directors and executive officers as a group.

Name	Shares of Common Stock Beneficially Owned		Shares of 5% Convertible Preferred Stock Beneficially Owned	
	Number	Percent	Number	Percent
Douglas H. Miller (2)(8)	859,122	11.4%	91,788	1.8%
T. W. Eubank (9)	263,407	3.6%	9,044	(1)
J. Douglas Ramsey (10)	179,586	2.4%	2,087	(1)
Jeffrey D. Benjamin (6)	118,230	1.6%	10,000	(1)
Earl E. Ellis (5)(7)	322,829	4.4%	26,000	(1)
J. Michael Muckleroy (3)(14)	130,029	1.8%	0	(1)
Boone Pickens (16)	261,743	3.5%	104,964	2.1%
Stephen F. Smith (15)	130,079	1.8%	25,000	(1)
J. David Choisser (11)	8,006	(1)	0	(1)
Charles R. Evans (4)(12)	85,933	1.2%	436	(1)
Richard E. Miller (13)	72,016	1.0%	1,035	(1)
All directors and executive officers as a group (11 persons)	2,430,980	29.2%	270,354	5.4%

(1) Less than 1%

(2) Does not include 16,500 shares of common stock owned by the Miller Children's Trust of which Mr. D. H. Miller is neither the trustee nor the beneficiary.

(3) Includes 60,000 shares of common stock held by Paine Webber, Inc. Cust FBO Richard Sinz Marital Trust and Paine Webber, Inc., Cust FBO Dorothy Sinz, for both of which Mr. Muckleroy is trustee.

(4) Includes 200 shares of common stock held by Mr. Evans as custodian for his children.

(5) Includes 63,450 shares of common stock held by Benjamin Jacobson and Sons, LLC in trust for which Mr. Ellis is the beneficiary, 3,200 shares of common stock held by Mr. Ellis' daughter, and 1,000 shares of 5% convertible preferred stock held by Mr. Ellis' wife.

(6) Includes 50,000 shares currently exercisable and/or vesting by May 31, 2003, under the 1998 Director Compensation Plan, and 10,000 shares of 5% convertible preferred stock.

(7) Includes 25,000 shares currently exercisable and/or vesting by May 31, 2003, under the 1998 Director Compensation Plan, and 26,000 shares of 5% convertible preferred stock.

(8) Includes 190,000 shares currently exercisable and/or vesting by May 31, 2003, under the 1998 Stock Option Plan, and 91,788 shares of 5% convertible preferred stock.

(9) Includes 110,000 shares currently exercisable and/or vesting by May 31, 2003, under the 1998 Stock Option Plan, and 9,044 shares of 5% convertible preferred stock.

(10) Includes 107,500 shares currently exercisable and/or vesting by May 31, 2003, under the 1998 Stock Option Plan, and 2,087 shares of 5% convertible preferred stock.

(11) Includes 7,812 shares currently exercisable and/or vesting by May 31, 2003, under the 1998 Stock Option Plan, and no shares of 5% convertible preferred stock.

(12) Includes 73,487 shares currently exercisable and/or vesting by May 31, 2003, under the 1998 Stock Option Plan, and 436 shares of 5% convertible preferred stock.

(13) Includes 58,021 shares currently exercisable and/or vesting by May 31, 2003, under the 1998 Stock Option Plan, and 1,035 shares of 5% convertible preferred stock.

(14) Includes 50,000 shares currently exercisable and/or vesting by May 31, 2003, under the 1998 Director Compensation Plan, and no shares of 5% convertible preferred stock.

(15) Includes 50,000 shares currently exercisable and/or vesting by May 31, 2003, under the 1998 Director Compensation Plan, and 25,000 shares of 5% convertible preferred stock.

(16) Includes 50,000 shares currently exercisable and/or vesting by May 31, 2003, under the 1998 Director Compensation Plan, and 104,964 shares of 5% convertible preferred stock.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2002 regarding compensation plans (including individual compensation arrangements) under which equity securities of EXCO are authorized for issuance:

EQUITY COMPENSATION PLAN INFORMATION

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights* (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity Compensation Plans Approved by Security Holders	2,049,831	$ 10.85	974,792
Equity Compensation Plans not Approved by Security Holders	—	—	—
Total	2,049,831	$ 10.85	974,792

*As adjusted for stock splits.

See Note 6 to our consolidated financial statements included in this annual report for information regarding the material features of the above plans. Each of the above plans provides that the number of shares with respect to which options may be granted, and the number of shares of common stock subject to an outstanding option, shall be proportionately adjusted in the event of a subdivision or consolidation of shares or the payment of a stock dividend on common stock, and the purchase price per share of outstanding options shall be proportionately revised.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Douglas H. Miller. Mr. D. H. Miller, a director and executive officer, received a loan in the form of a promissory note from the company for $450,000 on September 15, 1998, which was renewed on September 15, 2001, and repaid in full including accrued interest on November 29, 2002. The loan was secured by a pledge of 75,000 shares of Mr. D. H. Miller's common stock in the company.

Mr. D. H. Miller also received a loan in the form of a promissory note from the company for $465,625 on November 29, 1999, which was repaid in full including accrued interest on November 29, 2002. The loan was secured by a pledge of 77,500 shares of Mr. D. H. Miller's common stock in the company.

T. W. Eubank. Mr. Eubank, a director and executive officer, received a loan in the form of a promissory note from the company for $225,000 on September 15, 1998, which was repaid in full including accrued interest on June 20, 2001. The loan was secured by a pledge of 37,500 shares of Mr. Eubank's common stock in the company.

Mr. Eubank also received a loan in the form of a promissory note from the company for $240,625 on November 29, 1999, which was repaid in full including accrued interest on June 20, 2001. The loan was secured by a pledge of 40,000 shares of Mr. Eubank's common stock in the company.

J. Douglas Ramsey, Ph.D. Dr. Ramsey, a director and executive officer, received a loan in the form of a promissory note from the company for $150,000 on September 15, 1998, which was repaid in full including accrued interest on July 27, 2001. The loan was secured by a pledge of 25,000 shares of Dr. Ramsey's common stock in the company.

Richard E. Miller. Mr. R. E. Miller, an executive officer, received a loan in the form of a promissory note from the company for $60,000 on May 18, 2001. The loan bears interest at the rate of 6.44% and is due and payable on May 18, 2004. The loan is secured by a pledge of 10,000 shares of Mr. R. E. Miller's common stock in the company.

Mr. R. E. Miller also owns working and royalty interests in some wells we operate. Mr. R. E. Miller does not receive payments from us in excess of $60,000 per year from these interests.

Under the terms of each of the promissory notes Messrs. D. H. Miller, Eubank, Ramsey and R. E. Miller have timely paid all accrued interest due and payable.

Jeffrey D. Benjamin. Mr. Benjamin, a director, owns working interests in some wells in which we also own working interests but do not operate. Mr. Benjamin does not receive any payments from us from these interests.

J. Michael Muckleroy. Mr. Muckleroy, a director, owns working, royalty, and overriding royalty interests in some wells we operate. Mr. Muckleroy does not receive payments from us in excess of $60,000 per year from these interests.

ITEM 14. CONTROLS AND PROCEDURES

(a) *Evaluation of Disclosure Controls and Procedures.* The term "disclosure controls and procedures" is defined in Rule 13a-14(c) of the Securities Exchange Act of 1934, or the Exchange Act. This term refers to the controls and procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files under the Exchange Act is recorded, processed, summarized and reported within required time periods. Our Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer have evaluated the effectiveness of our disclosure controls and procedures as of a date within 90 days before the filing of this annual report, and they have concluded that as of that date, our disclosure controls and procedures were effective at ensuring that required information will be disclosed on a timely basis in our reports filed under the Exchange Act.

(b) *Changes in Internal Controls.* We maintain a system of internal controls that are designed to provide reasonable assurance that our books and records accurately reflect our transactions and that our established policies and procedures are followed. There were no significant changes to our internal controls or in other factors that could significantly affect our internal controls subsequent to the date of their evaluation by our Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, including any corrective actions with regard to significant and material weaknesses.

PART IV

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

1. Financial Statements

See Index to Financial Statements on page 57 to this annual report.

2. Financial Statement Schedules

All schedules are omitted because the information is not required under the related instructions or is inapplicable or because the information is included in our consolidated financial statements or related notes.

3. Exhibits

No.	Description of Exhibit
3.1	Restated Articles of Incorporation of EXCO filed as an Exhibit to EXCO's Form S-3/A filed June 2, 1998 and incorporated by reference herein.
3.2	Statement of Designation for 5% Convertible Preferred Stock, dated June 21, 2001, filed as an Exhibit to EXCO's Form 8-K/A filed June 29, 2001 and incorporated by reference herein.
3.3	Restated Bylaws of EXCO, as amended, filed as an Exhibit to EXCO's Form 10-K filed March 26, 2003 and incorporated by reference herein.
4.1	Restated Articles of Incorporation of EXCO filed as an Exhibit to EXCO's Form S-3/A filed June 2, 1998 and incorporated by reference herein.
4.2	Restated Bylaws of EXCO, as amended, filed as an Exhibit to EXCO's Form 10-K filed March 26, 2003 and incorporated by reference herein.
4.3	Specimen Stock Certificate for the Common Stock of EXCO filed as an Exhibit to EXCO's Pre-Effective Amendment No. 1 to Form S-2 filed on June 2, 1998 and incorporated by reference herein.
4.4	Credit Agreement among EXCO Resources, Inc. as borrower, and Bank One, NA and the institutions named herein as lenders, Bank One, NA, as administrative agent and Fleet National Bank, as syndication agent and BNP Paribas, as documentation agent and Banc One Capital Markets, Inc. as lead arranger and bookrunner, dated April 26, 2001, filed as an Exhibit to EXCO's Form 10-Q filed May 8, 2001 and incorporated by reference herein.
4.5	Credit Agreement among EXCO Resources Canada Inc. as borrower, and Bank One Canada and the institutions named herein as lenders, Bank One Canada, as administrative agent and BNP Paribas (Canada) as documentation agent and Banc One Capital Markets, Inc. as lead arranger and bookrunner, dated April 26, 2001, filed as an Exhibit to EXCO's Form 10-Q filed May 8, 2001 and incorporated by reference herein.
4.6	Statement of Designation for 5% Convertible Preferred Stock, dated June 21, 2001, filed as an Exhibit to EXCO's Form 8-K/A filed June 29, 2001 and incorporated by reference herein.
4.7	First Amendment to Credit Agreement among EXCO Resources Canada Inc. as borrower, and Bank One Canada and the institutions named herein as lenders, Bank One Canada, as administrative agent and BNP Paribas (Canada) as documentation agent and Banc One Capital Markets, Inc. as lead arranger and bookrunner, dated April 26, 2001, filed as an Exhibit to EXCO's Form 10-Q filed May 8, 2001 and incorporated by reference herein.

4.8 First Amendment to Credit Agreement among EXCO Resources, Inc. as borrower, and Bank One, NA and the institutions named herein as lenders, Bank One, NA, as administrative agent and Fleet National Bank, as syndication agent and BNP Paribas, as documentation agent and Banc One Capital Markets, Inc. as lead arranger and bookrunner, dated November 14, 2001, filed as an Exhibit to EXCO's Form 10-Q, dated November 14, 2001 and incorporated by reference herein.

4.9 Second Amendment to Credit Agreement among EXCO Resources Canada Inc. as borrower, and Bank One Canada and the institutions named herein as lenders, Bank One Canada, as administrative agent and BNP Paribas (Canada) as documentation agent and Banc One Capital Markets, Inc. as lead arranger and bookrunner, dated November 14, 2001, filed as an Exhibit to EXCO's Form 10-Q, dated November 14, 2001 and incorporated by reference herein.

4.10 Restated Credit Agreement among EXCO Resources, Inc. and EXCO Operating, LP, as borrowers, Bank One, NA, as administrative agent, BNP Paribas, as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and the financial institutions which are or may become Lenders, dated December 18, 2001, filed as an Exhibit to EXCO's Form 8-K filed January 2, 2002 and incorporated by reference herein.

4.11 Restated Credit Agreement among Addison Energy, Inc., as borrower, Bank One, NA, Canada Branch, as administrative agent, BNP Paribas (Canada), as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and the financial institutions which are or may become Lenders, dated December 18, 2001, filed as an Exhibit to EXCO's Form 8-K filed January 2, 2002 and incorporated by reference herein.

4.12 Amendment to Restated Credit Agreement among EXCO Resources, Inc. and EXCO Operating, LP, as borrowers, Bank One, NA, as administrative agent, BNP Paribas, as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and the financial institutions which are or may become Lenders, dated April 26, 2002 filed as an Exhibit to EXCO's Form 10-Q filed May 14, 2002 and incorporated by reference herein.

4.13 Amendment to Restated Credit Agreement among Addison Energy Inc., as borrower, Bank One, NA, Canada Branch, as administrative agent, BNP Paribas (Canada), as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and the financial institutions which are or may become Lenders, dated April 26, 2002 filed as an Exhibit to EXCO's Form 10-Q filed May 14, 2002 and incorporated by reference herein.

4.14 Second Amendment to Restated Credit Agreement among EXCO Resources, Inc. and EXCO Operating, LP, as borrowers, Bank One, NA, as administrative agent, BNP Paribas, as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and the financial institutions which are or may become Lenders, dated June 24, 2002 filed as an Exhibit to EXCO's Form 10-Q filed August 14, 2002 and incorporated by reference herein.

4.15 Second Amendment to Restated Credit Agreement among Addison Energy Inc., as borrower, Bank One, NA, Canada Branch, as administrative agent, BNP Paribas (Canada), as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and the financial institutions which are or may become Lenders, dated June 24, 2002 filed as an Exhibit to EXCO's Form 10-Q filed August 14, 2002 and incorporated by reference herein.

4.16 Third Amendment to Restated Credit Agreement among EXCO Resources, Inc. and EXCO Operating, LP, as borrowers, Bank One, NA, as administrative agent, BNP Paribas, as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and financial institutions which are or may become Lenders, dated September 30, 2002, filed as an Exhibit to EXCO's Form 10-Q filed November 14, 2002 and incorporated by reference herein.

4.17 Third Amendment to Restated Credit Agreement among Addison Energy Inc., as borrower, Bank One, NA, Canada Branch, as administrative agent, BNP Paribas (Canada), as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc., as lead arranger and bookrunner, and financial institutions which are or may become Lenders, dated September 30, 2002, filed as an Exhibit to EXCO's Form 10-Q filed November 14, 2002 and incorporated by reference herein.

4.18 Fourth Amendment to Restated Credit Agreement among EXCO Resources, Inc. and EXCO Operating, LP, as borrowers, Bank One, NA, as administrative agent, BNP Paribas, as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and financial institutions which are or may become Lenders dated November 22, 2002, filed as an Exhibit to EXCO's Form 8-K filed November 22, 2002 and incorporated by reference herein.

4.19 Fourth Amendment to Restated Credit Agreement among Addison Energy Inc., as borrower, Bank One, NA, Canada Branch, as administrative agent, BNP Paribas (Canada), as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc., as lead arranger and bookrunner, and financial institutions which are or may become Lenders, dated November 22, 2002, filed as an Exhibit to EXCO's Form 8-K filed November 22, 2002 and incorporated by reference herein.

10.1* EXCO Resources, Inc. 1998 Stock Option Plan, filed as Appendix A to EXCO's Proxy Statement dated March 17, 1998 and incorporated by reference herein.

10.2* Amendment No. 1 to the EXCO Resources, Inc. 1998 Stock Option Plan, filed as Exhibit 10.10 to EXCO's Form 10-Q dated May 17, 1999 and incorporated by reference herein.

10.3* Amendment No. 2 to EXCO Resources, Inc. 1998 Stock Option Plan filed as Exhibit 4.6 to Form S-8 filed April 26, 2001 and incorporated by reference herein.

10.4* Amendment No. 3 to the EXCO Resources, Inc. 1998 Stock Option Plan filed as Exhibit 4.8 to Form S-8 filed May 10, 2002 and incorporated by reference herein.

10.5* EXCO Resources, Inc. 1998 Director Compensation Plan filed as Appendix D to EXCO's Proxy Statement dated March 16, 1999 and incorporated by reference herein.

10.6 Credit Agreement among EXCO Resources, Inc. as borrower, and Bank One, NA and the institutions named herein as lenders, Bank One, NA, as administrative agent and Fleet National Bank, as syndication agent and BNP Paribas, as documentation agent and Banc One Capital Markets, Inc. as lead arranger and bookrunner, dated April 26, 2001, filed as an Exhibit to EXCO's Form 10-Q filed May 8, 2001 and incorporated by reference herein.

10.7 Credit Agreement among EXCO Resources Canada Inc. as borrower, and Bank One Canada and the institutions named herein as lenders, Bank One Canada, as administrative agent and BNP Paribas (Canada) as documentation agent and Banc One Capital Markets, Inc. as lead arranger and bookrunner, dated April 26, 2001, filed as an Exhibit to EXCO's Form 10-Q filed May 8, 2001 and incorporated by reference herein.

10.8 First Amendment to Credit Agreement among EXCO Resources Canada Inc. as borrower, and Bank One Canada and the institutions named herein as lenders, Bank One Canada, as administrative agent and BNP Paribas (Canada) as documentation agent and Banc One Capital Markets, Inc. as lead arranger and bookrunner, dated April 26, 2001, filed as an Exhibit to EXCO's Form 10-Q filed May 8, 2001 and incorporated by reference herein.

10.9 First Amendment to Credit Agreement among EXCO Resources, Inc. as borrower, and Bank One, NA and the institutions named herein as lenders, Bank One, NA, as administrative agent and Fleet National Bank, as syndication agent and BNP Paribas, as documentation agent and Banc One Capital Markets, Inc. as lead arranger and bookrunner, dated November 14, 2001, filed as an Exhibit to EXCO's Form 10-Q filed November 14, 2001 and incorporated by reference herein.

10.10 Second Amendment to Credit Agreement among EXCO Resources Canada Inc. as borrower, and Bank One Canada and the institutions named herein as lenders, Bank One Canada, as administrative agent and BNP Paribas (Canada) as documentation agent and Banc One Capital Markets, Inc. as lead arranger and bookrunner, dated November 14, 2001, filed as an Exhibit to EXCO's Form 10-Q filed November 14, 2001 and incorporated by reference herein.

10.11 Agreement of Purchase and Sale among PrimeWest Energy Inc. and PrimeWest Oil and Gas Corp., as sellers, and Addison Energy Inc., as buyer, dated November 22, 2001, filed as an Exhibit to EXCO's Form 8-K filed January 2, 2002 and incorporated by reference herein.

10.12 Restated Credit Agreement among EXCO Resources, Inc. and EXCO Operating, LP, as borrowers, Bank One, NA, as administrative agent, BNP Paribas, as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and the financial institutions which are or may become Lenders, dated December 18, 2001, filed as an Exhibit to EXCO's Form 8-K filed January 2, 2002 and incorporated by reference herein.

10.13 Restated Credit Agreement among Addison Energy Inc., as borrower, Bank One, NA, Canada Branch, as administrative agent, BNP Paribas (Canada), as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and the financial institutions which are or may become Lenders, dated December 18, 2001, filed as an Exhibit to EXCO's Form 8-K filed January 2, 2002 and incorporated by reference herein.

10.14 Amendment to Restated Credit Agreement among EXCO Resources, Inc. and EXCO Operating, LP, as borrowers, Bank One, NA, as administrative agent, BNP Paribas, as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and the financial institutions which are or may become Lenders, dated April 26, 2002 filed as an Exhibit to EXCO's Form 10-Q filed May 14, 2002 and incorporated by reference herein.

10.15 Amendment to Restated Credit Agreement among Addison Energy Inc., as borrower, Bank One, NA, Canada Branch, as administrative agent, BNP Paribas (Canada), as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and the financial institutions which are or may become Lenders, dated April 26, 2002 filed as an Exhibit to EXCO's Form 10-Q filed May 14, 2002 and incorporated by reference herein.

10.16 Second Amendment to Restated Credit Agreement among EXCO Resources, Inc. and EXCO Operating, LP, as borrowers, Bank One, NA, as administrative agent, BNP Paribas, as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and the financial institutions which are or may become Lenders, dated June 24, 2002 filed as an Exhibit to EXCO's Form 10-Q filed August 14, 2002 and incorporated by reference herein.

10.17 Second Amendment to Restated Credit Agreement among Addison Energy Inc., as borrower, Bank One, NA, Canada Branch, as administrative agent, BNP Paribas (Canada), as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and the financial institutions which are or may become Lenders, dated June 24, 2002 filed as an Exhibit to EXCO's Form 10-Q filed August 14, 2002 and incorporated by reference herein.

10.18 Third Amendment to Restated Credit Agreement among EXCO Resources, Inc. and EXCO Operating, LP, as borrowers, Bank One, NA, as administrative agent, BNP Paribas, as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and financial institutions which are or may become Lenders, dated September 30, 2002 filed as an Exhibit to EXCO's Form 10-Q filed November 14, 2002 and incorporated by reference herein.

10.19 Third Amendment to Restated Credit Agreement among Addison Energy Inc., as borrower, Bank One, NA, Canada Branch, as administrative agent, BNP Paribas (Canada), as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc., as lead arranger and bookrunner, and financial institutions which are or may become Lenders, dated September 30, 2002 filed as an Exhibit to EXCO's Form 10-Q filed November 14, 2002 and incorporated by reference herein.

10.20 Fourth Amendment to Restated Credit Agreement among EXCO Resources, Inc. And EXCO Operating, LP, as borrowers, Bank One, NA, as administrative agent, BPN Paribas, as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc. as lead arranger and bookrunner, and financial institutions which are or may become Lenders dated November 22, 2002, filed as an Exhibit to EXCO's Form 8-K filed November 22, 2002 and incorporated by reference herein.

10.21 Fourth Amendment to Restated Credit Agreement among Addison Energy, Inc., as borrower, Bank One, NA, Canada Branch, as administrative agent, BNP Paribas (Canada), as syndication agent, The Bank of Nova Scotia, as documentation agent, Bank One Capital Markets, Inc., as lead arranger and bookrunner, and financial institutions which are or may become Lenders, dated November 22, 2002, filed as an Exhibit to EXCO's Form 8-K filed November 22, 2002 and incorporated by reference herein.

10.22* Severance Plan of EXCO Resources, Inc., effective as of August 15, 2002 filed as an Exhibit to EXCO's Form 10-Q filed November 14, 2002 and incorporated by reference herein.

10.23 Agreement of Purchase and Sale between Devon Canada, as vendor, and Addison Energy Inc., as purchaser, dated January 25, 2002 filed as an Exhibit to EXCO's Form 10-Q filed November 14, 2002 and incorporated by reference herein.

10.24 Purchase and Sale Agreement between Southwestern Eagle, L.L.C. and SW Production Company, as sellers, and EXCO Resources, Inc., as buyer, dated October 18, 2002 filed as an Exhibit to EXCO's Form 8-K filed November 12, 2002 and incorporated by reference herein.

10.25* Promissory Note dated May 18, 2001 by and between Richard E. Miller, as maker, and EXCO Resources, Inc., as payee, filed as an Exhibit to EXCO's Form 10-K filed March 26, 2003 and incorporated by reference herein.

10.26* Pledge Agreement dated May 19, 2001 by and between Richard E. Miller, as pledger, and EXCO Resources, Inc., as the secured party, filed as an Exhibit to EXCO's Form 10-K filed March 26, 2003 and incorporated by reference herein.

10.27 Form of Addison Energy Inc. Stock Option Agreement effective as of June 30, 2002, filed as an Exhibit to EXCO's Form 10-K filed March 26, 2003 and incorporated by reference herein.

10.28 Agreement and Plan of Merger among EXCO Resources, Inc., EXCO Holdings Inc. and ER Acquisition, Inc., dated March 11, 2003 filed as an Exhibit to EXCO's Form 8-K filed March 12, 2003 and incorporated by reference herein.

10.29 Agreement dated October 14, 2002, by and between EXCO Resources, Inc. and Douglas H. Miller, and any person who executes a joinder agreement, filed as an exhibit to Douglas H. Miller's Schedule 13D/A filed October 14, 2002 and incorporated by reference herein.

21.1 Subsidiaries of EXCO Resources, Inc., filed as an Exhibit to EXCO's Form 10-K filed March 26, 2003 and incorporated by reference herein.

23.1 Consent of Independent Accountants, Ernst & Young LLP, filed as an Exhibit to EXCO's Form 10-K filed March 26, 2003 and incorporated by reference herein.

23.2 Consent of Independent Petroleum Engineers, Lee Keeling and Associates, Inc., filed as an Exhibit to EXCO's Form 10-K filed March 26, 2003 and incorporated by reference herein.

23.3 Consent of Independent Accountants, Ernst & Young LLP, dated June 30, 2003 (filed herewith).

99.1 Certification of Douglas H. Miller, Chairman of the Board and Chief Executive Officer of EXCO Resources, Inc., dated June 30, 2003, relating to Amendment No. 1 to EXCO's Annual Report on Form 10-K/A and EXCO's Annual Report on Form 10-K originally filed March 26, 2003, for the year ended December 31, 2002 (filed herewith).

99.2 Certification of J. Douglas Ramsey, Vice President and Chief Financial Officer of EXCO Resources, Inc., dated June 30, 2003, relating to Amendment No. 1 to EXCO's Annual Report on Form 10-K/A and EXCO's Annual Report on Form 10-K originally filed March 26, 2003, for the year ended December 31, 2002 (filed herewith).

99.3 Share Acquisition Agreement between Douglas H. Miller and EXCO Resources, Inc. dated as of October 14, 2002 filed as an Exhibit to Mr. Miller's 13D filed October 24, 2002 and incorporated by reference herein.

99.4 Joinder of T. W. Eubank to that certain Share Acquisition Agreement between Douglas H. Miller and EXCO Resources, Inc. dated as of October 23, 2002 filed as an Exhibit to Mr. Miller's 13D filed October 24, 2002 and incorporated by reference herein.

---

*These exhibits are management contracts.

4. Reports on Form 8-K

Current report on Form 8-K dated November 1, 2002 pursuant to Item 2 reporting the acquisition of properties from Southwestern Eagle, L.L.C. and SW Production Company.

Current report on Form 8-K dated November 22, 2002 pursuant to Item 5 reporting the signing of the fourth amendments to our restated U.S. and Canadian credit agreements, increases in the borrowing base under each agreement, and the addition of a new lender to the U.S. bank group.

Current report on Form 8-K dated December 27, 2002 pursuant to Item 5 reporting the receipt of a revised proposal for the acquisition of the company by a group led by the company's Chairman and Chief Executive Officer, Douglas H. Miller. The new proposal increased the consideration for our common stock to $18.00 per share and the consideration for our 5% convertible preferred stock to be between $18.00 and $18.525 per share, depending upon the date of the closing.

SIGNATURE PAGE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act, the Registrant has duly caused this Form 10-K/A Amendment No. 1 to be signed on its behalf by the undersigned, there unto duly authorized in the City of Dallas, Texas on the 30th of June, 2003.

EXCO RESOURCES, INC.

By: /s/ DOUGLAS H. MILLER

Douglas H. Miller
Chairman of the Board of Directors
and Chief Executive Officer

CERTIFICATION

I, Douglas H. Miller, Chief Executive Officer of EXCO Resources, Inc. certify that:

1. I have reviewed this annual report on Form 10-K of EXCO Resources, Inc.;

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; and

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 functions):

   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: June 30, 2003

/s/ DOUGLAS H. MILLER

Douglas H. Miller
Chief Executive Officer

CERTIFICATION

I, J. Douglas Ramsey, Chief Financial Officer of EXCO Resources, Inc., certify that:

1. I have reviewed this annual report on Form 10-K of EXCO Resources, Inc.;

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; and

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 functions):

   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: June 30, 2003

/s/ J. DOUGLAS RAMSEY

J. Douglas Ramsey
Chief Financial Officer

CERTIFICATION

I, J. David Choisser, Chief Accounting Officer of EXCO Resources, Inc. certify that:

1. I have reviewed this annual report on Form 10-K of EXCO Resources, Inc.;

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; and

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 functions):

   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: June 30, 2003

/s/ J. DAVID CHOISSER

J. David Choisser
Chief Accounting Officer

INFORMATION FOR SHAREHOLDERS AND INVESTORS

EXCO RESOURCES, INC.

6500 Greenville Avenue
Suite 600, LB17
Dallas, Texas 75206
214-368-2084

Shareholder Relations
Donna Sablotny
214-706-3310

Nasdaq NMS Symbols
EXCO - Common Stock
EXCOP - 5% Convertible Preferred Stock

Legal Counsel
Haynes and Boone, LLP
2505 N. Plano Rd., Suite 4000
Richardson, Texas 75082

Auditors
Ernst & Young LLP
2121 San Jacinto Street, Suite 1500
Dallas, Texas 75201

Stock Transfer Agent
Continental Stock Transfer & Trust Company
Communications concerning transfer or exchange requirements, lost certificates, share holdings or changes of address should be directed to:
17 Battery Place, 8th Floor
New York, New York 10004
212-509-4000

Number of Shareholders
725
(As of February 28, 2003)

OFFICERS

Douglas H. Miller
Chairman of the Board and
Chief Executive Officer

T.W. Eubank
President and Treasurer

J. Douglas Ramsey, Ph.D.
Vice President and
Chief Financial Officer

Richard E. Miller
Vice President, Secretary
and General Counsel

Charles R. Evans
Vice President and
Chief Operating Officer

J. David Choisser, CPA
Vice President and
Chief Accounting Officer

Richard L. Hodges
Vice President

John D. Jacobi
Vice President

Daniel A. Johnson
Vice President

James M. Perkins, Jr.
Vice President

DIRECTORS

Douglas H. Miller
Chairman of the Board and
Chief Executive Officer,
EXCO Resources, Inc.

T.W. Eubank
President and Treasurer,
EXCO Resources, Inc.

J. Douglas Ramsey, Ph.D.
Vice President and
Chief Financial Officer,
EXCO Resources, Inc.

Jeffrey D. Benjamin[1,2]
Apollo Management, L.P.

Earl E. Ellis[1]
Private Investments
Former Managing Partner,
Benjamin Jacobson & Sons, LLC

J. Michael Muckleroy[2]
Private Investments
Former Chairman
and Chief Executive Officer,
Enron Liquid Fuels

Boone Pickens[2]
Chairman,
BP Capital LLC

Stephen F. Smith[1]
Executive Vice President,
Sandefer Oil & Gas, Inc.

[1] Audit Committee Member
[2] Compensation Committee Member

Reverse Stock Split History

March 2, 1992	1 for 10 Reverse Stock Split — Mineral Development, Inc. (predecessor name)
July 19, 1996	1 for 5 Reverse Stock Split — EXCO Resources, Inc.
March 31, 1998	1 for 2 Reverse Stock Split — EXCO Resources, Inc.

EXCO

EXCO Resources, Inc.