THRIVING IN A VOLATILE ENVIRONMENT

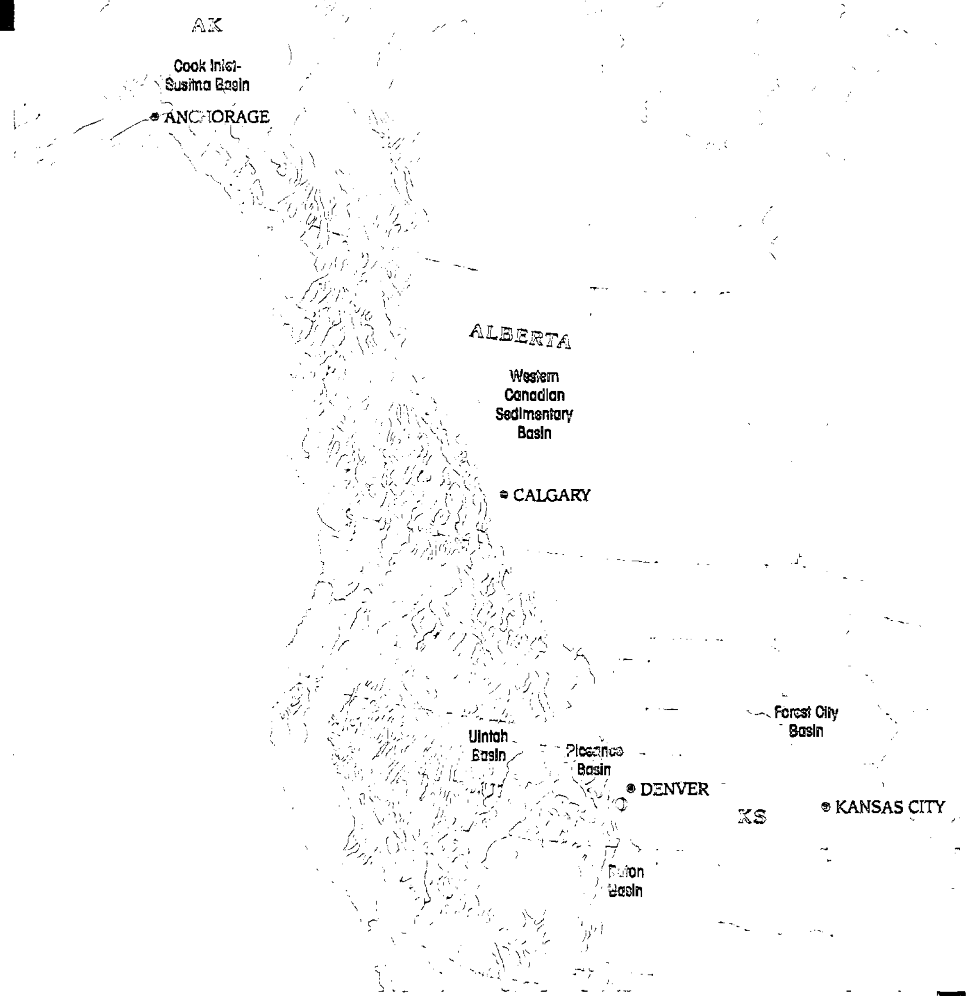
EVERGREEN
RESOURCES, INC.

ANNUAL REPORT 2003

ABOUT THE COVER

Ours is a tough business. Exploration and production companies face extreme commodity price volatility, strict government regulations and fierce opposition from anti-development groups, to name just a few. Roughly half of the energy companies that were operating in 1990 no longer exist. Evergreen Resources has not just survived, we have thrived in this volatile environment.

With an emphasis on applying leading-edge technology to unconventional natural gas plays, we continue to generate some of the lowest finding and development costs in industry, while maintaining a competitive operating cost structure. Our business model has helped us generate positive net income from continuing operations in every quarter since September 1996, even though this industry is not known for creating earnings consistently. We have grown the company while respecting the environment and mitigating the impact of our operations.



REGION	DEVELOPED ACRES GROSS	DEVELOPED ACRES NET	UNDEVELOPED ACRES GROSS	UNDEVELOPED ACRES NET	TOTAL GROSS	TOTAL NET
☐ Raton Basin	186,728	169,050	198,695	173,139	385,423	342,189
☐ Piceance and Uintah Basins	47,914	42,341	145,621	128,984	193,535	171,325
☐ Western Canadian Sedimentary Basin	86,080	40,568	71,313	60,106	157,393	100,674
☐ Forest City Basin	-	-	714,739	667,492	714,739	667,492
☐ Alaska	-	-	294,890	293,851	294,890	293,851
Other	1,740	798	28,771	20,778	30,511	21,576
Total	322,462	252,757	1,454,029	1,344,350	1,776,491	1,597,107

MISSION STATEMENT

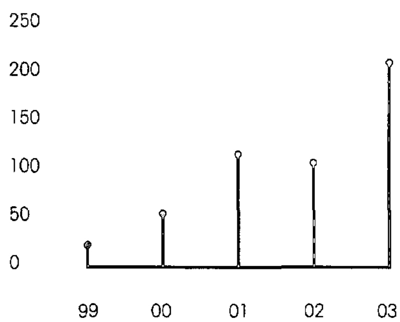
Our goal is to grow into a multi-billion dollar corporation by developing high impact natural gas projects, with annual reserves, production growth and returns to shareholders exceeding 15%. We maintain our competitive edge and accelerated growth with focused management, innovative industry professionals, attention to detail, quality control and vertical service integration. We are committed to being a leader in environmentally responsible development, community enrichment and integrity in our business practices.

FINANCIAL HIGHLIGHTS

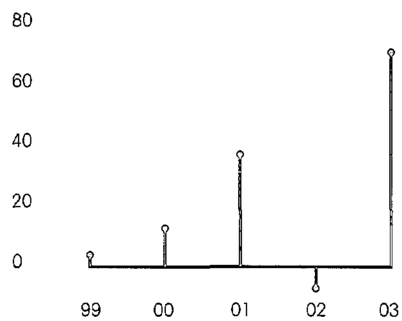
(In thousands except per share and Mcfe amounts)	**2003**	2002	2001	2000	1999
Revenues	**$ 216,440**	$ 112,126	$ 120,770	$ 59,693	$ 26,929
Net Income (Loss)	**$ 72,628**	$ (8,324)	$ 38,527	$ 14,063	$ 5,127
Per Diluted Share	**$ 1.77**	$ (0.22)	$ 0.99	$ 0.43	$ 0.19
Production - MMcfe	**46,268**	38,988	30,807	19,521	13,656
Average Price Per Mcfe	**$ 4.66**	$ 2.86	$ 3.89	$ 3.03	$ 1.96
Proven Reserves – Bcfe	**1,495**	1,239	1,051	875	559
Present value of future net cash flows at 10% discount before income taxes	**$ 2,712,603**	$ 1,634,741	$ 598,462	$ 2,920,166	$ 331,383
Year-end Price Per Mcfe (1)	**$ 5.49**	$ 4.22	$ 2.32	$ 9.18	$ 2.31

(1) Calculated year-end average sales price utilized for purposes of estimating company's proven reserves and future net revenues.

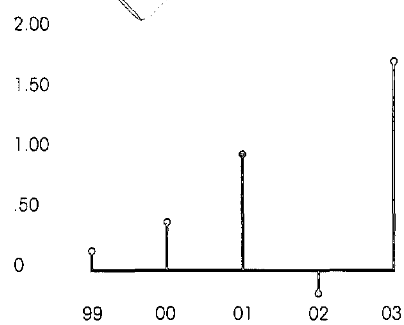
Revenues (in millions of dollars)



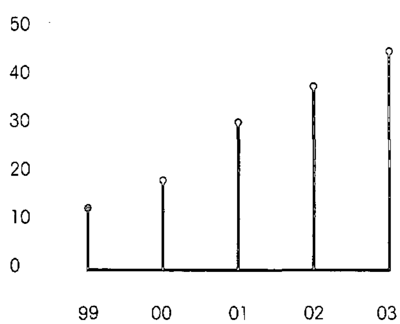
Net Income (in millions of dollars)



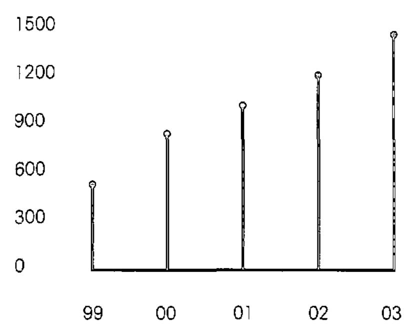
Net Income Per Diluted Share (in dollars)



Annual Production (net sales–Bcfe)



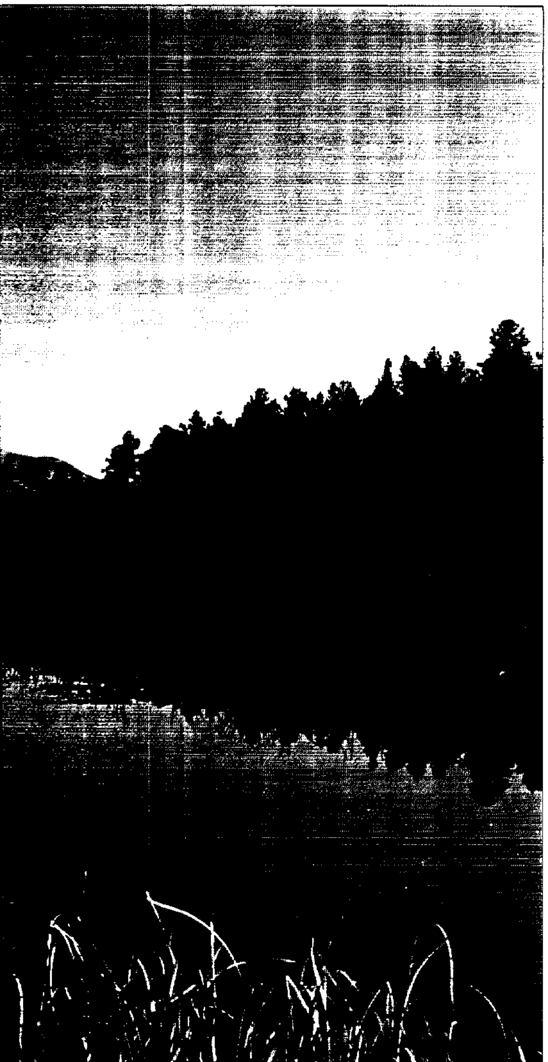
Proven Reserves (in Bcfe)



LETTER TO SHAREHOLDERS

While produced water from coal bed methane (CBM) operations has been a contentious issue in many of the nation's coal basins, Evergreen continues to identify and implement projects for the beneficial use by landowners of its produced water in the semi-arid Raton Basin in southern Colorado.

Mark S. Sexton
President & CEO



I am pleased to report that Evergreen closed an exciting 2003 with our 35th consecutive quarter of production growth. We enter 2004 with a series of projects in addition to our core area of southern Colorado, leading us to expect continued growth for the foreseeable future. While the challenges for natural resource development continue to increase, Evergreen not only survives, but flourishes in a volatile environment.

By constantly monitoring, reviewing and improving our performance, and by focusing on innovation, we set new records every year and did so again in 2003. Highlights of the year are as follows:

- Reserves grew 21% to 1.495 Tcfe
- Production increased 19% to 46.3 Bcfe
- Net income increased to $72.6 million
- Oil and gas revenues nearly doubled to $215.5 million
- Wells drilled increased to 181
- Net producing wells increased to 1,158
- We completed a strategic acquisition, adding 97 Bcfe and producing properties in three new core areas
- We completed abandonment of all projects outside North America

In 2003 we expanded our business model to other geographic areas. It was a breakthrough year for Evergreen as we now produce and market unconventional natural gas from multiple basins.

At the end of last year's first quarter, we announced the acquisition of Carbon Energy, which we believe is a perfect fit with our focus on North American unconventional natural gas properties. These new properties provide production diversification into new areas. More exciting to us are the long-term growth opportunities to increase production and reserves through additional development and exploratory drilling in multiple formations. We have allocated nearly one-third of our 2004 capital budget to develop these areas aggressively.

As a result of the Carbon acquisition, we have added reserves and new production in three new core areas: the Piceance Basin in western Colorado, the Uintah Basin in eastern Utah and the Western Canadian Sedimentary Basin. We believe our vertically integrated business model will provide significant improvements to operating results and cost efficiencies in each of these new areas.

To supplement our strategy of developing North American unconventional natural gas, we have assembled large exploratory acreage positions in eastern Kansas (Forest City Basin) and south-central Alaska (Cook Inlet-Susitna Basin). These exploration components provide balance to the acquisition and development growth of our core producing areas.

We began our exploratory project in eastern Kansas in the second half of 2003. In 2004, we will evaluate the potential of the Forest City Basin to produce from a series of thin interbedded sands, shales and coals, utilizing our specialized completion techniques. By the end of the year, we expect to have approximately 100 wells production testing from numerous separate pilot areas to evaluate the more than 700,000 acres we have leased.

In Alaska, we determined that our first two 4-well pilot areas were not economic. At the end of 2003, we began drilling five geologic test wells. Results from these tests of the Tyonek coals will determine where future shallow gas pilots will be drilled. In total, our leases comprise about 300,000 acres in the Cook Inlet-Susitna Basin.

In our long-standing operational core area, the Raton Basin, we are now producing from more than

1,000 CBM wells, and we have at least 1,000 wells left to drill. At our current accelerated rate of 200 wells per year, this provides in excess of five years of drilling inventory in this area alone. We expect to continue to add shareholder value as long as we are drilling wells in the Raton Basin.

Of our year-end 2003 total estimated proved reserves of approximately 1.5 Tcfe, 62% were classified as proved developed and the remaining 38% as proved undeveloped. The year-end 2003 reserve estimate was based on a total of 1,957 gross wells, including 555 classified as proved undeveloped locations. The year-end reserve estimate included insignificant revisions (less than 1%). Independent petroleum engineering consultants Netherland, Sewell & Associates, Inc. ("NSAI") audited 100% of our Raton Basin well locations and prepared the year-end reserve estimate for the Piceance, Uintah and Canadian properties. We are confident in the quality of our reserve base and our ability to significantly grow reserves in each of our development areas.

Evergreen is one of the fortunate few energy companies that has plenty of drilling inventory, as well as solid expectations for reserves and production growth. However, natural gas production in the U.S. and Canada appears to have peaked and, with national demand growing steadily, the result is a strong natural gas price environment. The 30-Tcf prediction for annual domestic demand cannot be supplied by U.S. natural gas producers. Our country should address predictable short-term natural gas supply shortages that will likely cause continued price volatility.

Industry and consumers desperately need natural gas from all sources: offshore, conventional onshore, unconventional, Canada, Alaska and liquefied natural gas (LNG). Evergreen is well positioned for the next decade to be a growing provider of unconventional natural gas supplies.

Beyond natural gas, the U.S. needs all the economically producible energy that we can get—coal, oil, hydroelectric, wind, nuclear, biomass, solar and other renewables. Strong environmental considerations accompany these energy choices, particularly air quality and land use.

Natural gas is clearly the environmentally friendly fuel of choice and the logical energy-supply bridge to a future hydrogen-based economy. We need advances in, and public acceptance of, all economic sources of energy. We also need to conserve; our energy supplies are simply too valuable to waste.

While organized anti-development groups oppose even the most responsible energy projects, Evergreen and a growing number of energy producers have challenged ourselves to deliver energy supplies using the most environmentally compatible methods available. We are committed to continuing our leadership toward environmentally responsible development, wherever Evergreen operates.

All of us at Evergreen are dedicated to growing the company the right way, to respecting all of our business relationships, to upholding the highest of standards in corporate governance, to continuing our innovative methods and to building value for our shareholders.

We are well positioned to continue our consistent, predictable and profitable growth profile:

- We hold long-lived reserves from geographically diverse core areas;
- Our business strategy continues to be well executed, with a focus on unconventional North American natural gas;
- Our low-cost structure is maintained through control of operations, economies of scale, vertical integration and technological innovation;
- Our low-risk, development-oriented growth profile is augmented with exploration upside and opportunities for strategic acquisitions in our core operating areas;
- We have a proven ability to generate sustained growth while demonstrating financial discipline;
- Our strong balance sheet provides us tremendous flexibility in allocating capital resources for future development; and
- We are well positioned to take advantage of the cyclical nature of energy prices by selling natural gas forward in up-cycles and acquiring quality assets in down-cycles.

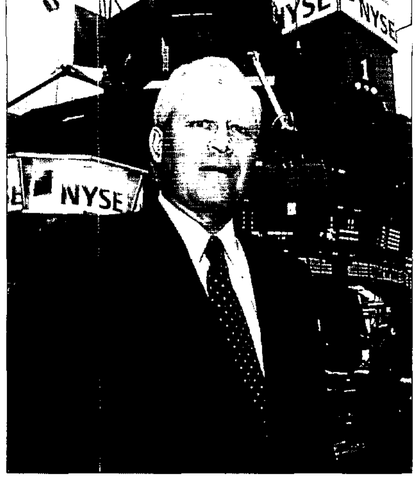
We look forward to another record year in 2004. Watch us for what promises to be a prosperous and fascinating year of growth for Evergreen Resources, thriving in a volatile environment.

Sincerely,

Mark S. Sexton

MARK S. SEXTON
President & CEO
March 15, 2004

FINANCIAL OVERVIEW



Kevin R. Collins
Executive VP – Finance & CFO

2003 was a record year for Evergreen in essentially every financial and operating category. We increased our production and reserves 19% and 21%, respectively, virtually all through the drillbit, and saw our natural gas revenues nearly double from 2002 levels. Evergreen's share price soared 45% during 2003, from $22.43 to $32.51. Since Evergreen began producing natural gas from the Raton Basin in January 1995, the company's share price has increased 1,138%, a compound annual rate of 32%.

Our confidence in our continued growth led to a 2-for-1 stock split, which became effective September 16, 2003, with the company's share price opening at $27.11 on the New York Stock Exchange. All common stock and per-share information for all periods presented in this annual report have been adjusted to reflect the 2-for-1 stock split.

We have continued to grow the company organically and have supplemented this growth with strategic acquisitions. We have a solid balance sheet, increasing cash flow from operations, strong natural gas price fundamentals, growing production and reserves and a low cost structure.

Evergreen's total operating costs continue to rank among the lowest in the E&P sector. Our operating costs, which consist of lease operating expenses, transportation costs, production and property taxes, general and administrative expenses, and interest expense, totaled $1.50 per Mcfe in 2003. Including depreciation, depletion and amortization expense of 58 cents per Mcfe and other expenses of 10 cents per Mcfe, our total pre-tax cost structure was approximately $2.18 per Mcfe in 2003. That translates to a pre-tax margin on production of $2.48 per Mcfe or 53%.

We exited the year 2003 with $249 million in outstanding debt, comprised of $100 million in convertible notes and $149 million in bank debt. Total debt to total proved reserves was $0.17 per Mcfe and total debt to total book capitalization was 34% at December 31, 2003. These credit metrics are in the E & P sector's upper tier.

Interest rates have continued to be at historically low levels. In March 2004, we took advantage of this low-interest rate environment to fix long-term interest rates by issuing $200 million of Senior Subordinated Notes at 5.875% and then using the net proceeds to retire our bank debt and its associated variable interest rates. The notes, which are due in 2012 and non-callable for four years, are rated Ba3/BB- by Moody's Investor Services and Standard & Poor's, respectively. Our balance sheet is strong and flexible with total outstanding debt at March 15, 2004 of $300 million, at an average fixed interest rate of 5.6% and an average life of debt of more than 11 years. In addition we have $200 million available under our current bank facility, which has been rated BBB+ by Standard & Poor's. We will continue to manage our leverage and be prudent with debt issuance.

Corporate Governance

Evergreen is committed to complying with the policies, practices and procedures required under the Sarbanes-Oxley Act of 2002, Securities and Exchange Commission rules and corporate governance listing standards of the New York Stock Exchange. While complying with governance standards is expensive, we have allocated the necessary resources to ensure that the company meets or exceeds the requirements of applicable laws and rules.

Evergreen has established written charters for three standing committees of the Board of Directors, the Audit, Compensation, and Corporate Governance and Nominating committees, which outline each committee's purpose, organization and responsibilities. The Board also adopted corporate governance guidelines and a code of ethics setting forth business practices and compliance procedures for all employees. We welcome the new governance standards as an added protection for shareowners in publicly traded ventures.

Outlook For 2004

We have capitalized on the winter spike in natural gas prices and have entered into financial swaps representing approximately two-thirds of our expected 2004 production at an average price of $4.67 per Mcfe, the NYMEX equivalent of better than $5.00 per Mcf. These hedging arrangements, along with the currently strong gas-price environment, will provide us with a level of cash flow to substantially fund our 2004 capital budget.

Evergreen's capital budget for 2004 is estimated to be $220 million. Of this total, approximately one-half will be for CBM operations in the Raton Basin, including $47 million for drilling and completing 200 wells, $34 million for infrastructure, and $28 million for recompletions and other remediation work and well equipment.

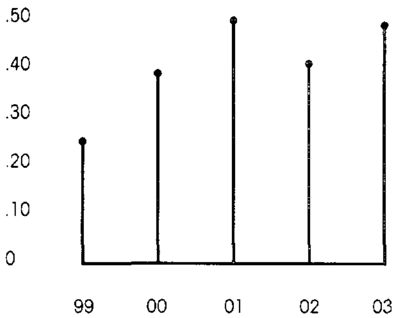
With solid production and a strong revenue stream from the Raton Basin, we are expanding into other areas with significant upside potential. In the Piceance and Uintah Basins, we plan to drill 55 gross wells with total drilling and completion costs of approximately $18 million, infrastructure costs of $5 million and $11 million of other costs, primarily for remediation work and well equipment. Total gross wells to be drilled in Canada are estimated at 65 with total drilling and completion costs of $21 million and $13 million for property acquisitions and other costs.

Of our total exploration expenditures, approximately $33 million will be directed to the Forest City Basin and $2 million to Alaska.

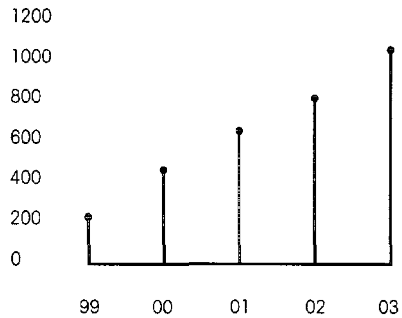
With about two-thirds of our expected 2004 production hedged, anticipated production gains of more than 35%, and our low cost structure, we believe that 2004 will be another record year for Evergreen and our shareholders.

KEVIN R. COLLINS
Executive Vice President – Finance & Chief Financial Officer

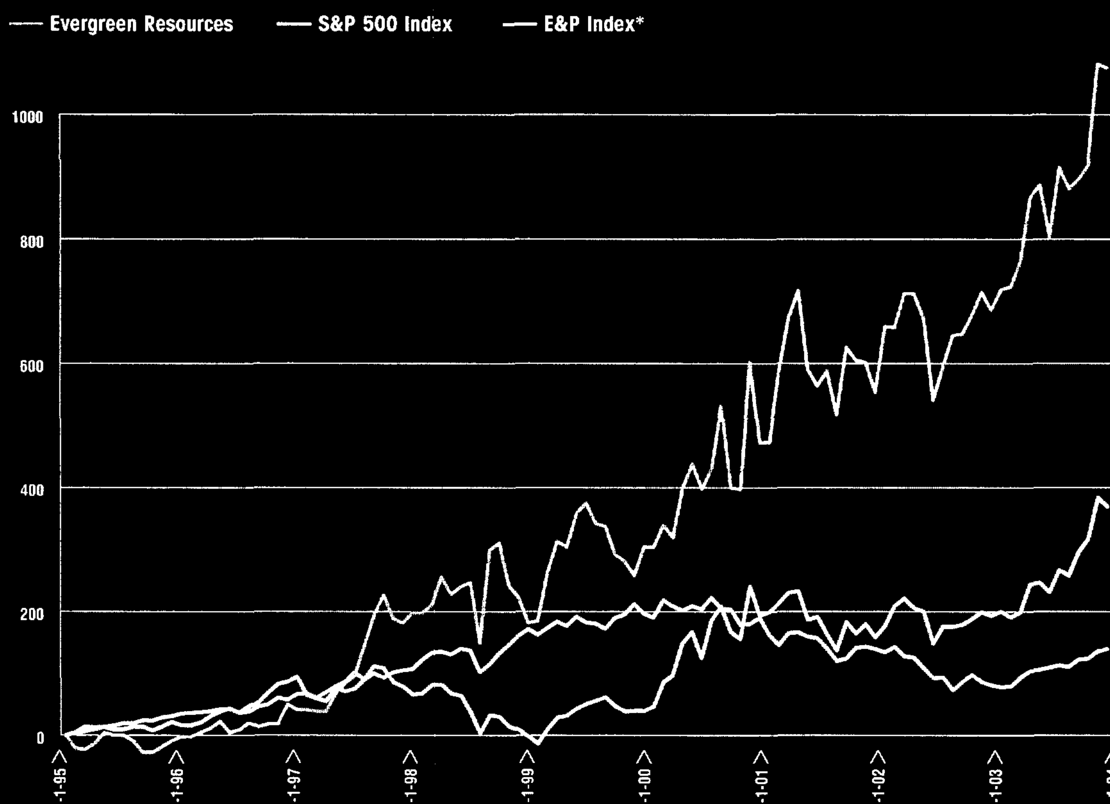
F&D Costs – Drilling and Revisions
(in dollars per Mcfe)



Total Net Producing Wells At Year End



RELATIVE PRICE PERFORMANCE



* E&P INDEX INCLUDES 26 U.S. INDEPENDENT E&P COMPANIES

The heart of Evergreen's CBM operations in the Raton Basin.

(L to R)
Dennis R. Carlton
Executive Vice President of Exploration and COO
Stephanie Basey
Raton Basin Operations Manager
J. Scott Zimmerman
Vice President of Operations and Engineering

Raton Basin

The Raton Basin has been a company-maker for Evergreen. Since we first acquired undeveloped acreage in the Basin in 1991, we have generated 1.4 Tcfe of proven natural gas reserves, net of production, and raised daily net sales to more than 130 MMcfe. Today, we hold mostly 100% working interests in more than 300,000 acres, making us the largest leaseholder in the Colorado portion of the Basin, and we currently operate more than 1,000 wells. At year-end 2003, our natural gas output continued to represent approximately two-thirds of the entire Basin's total production.

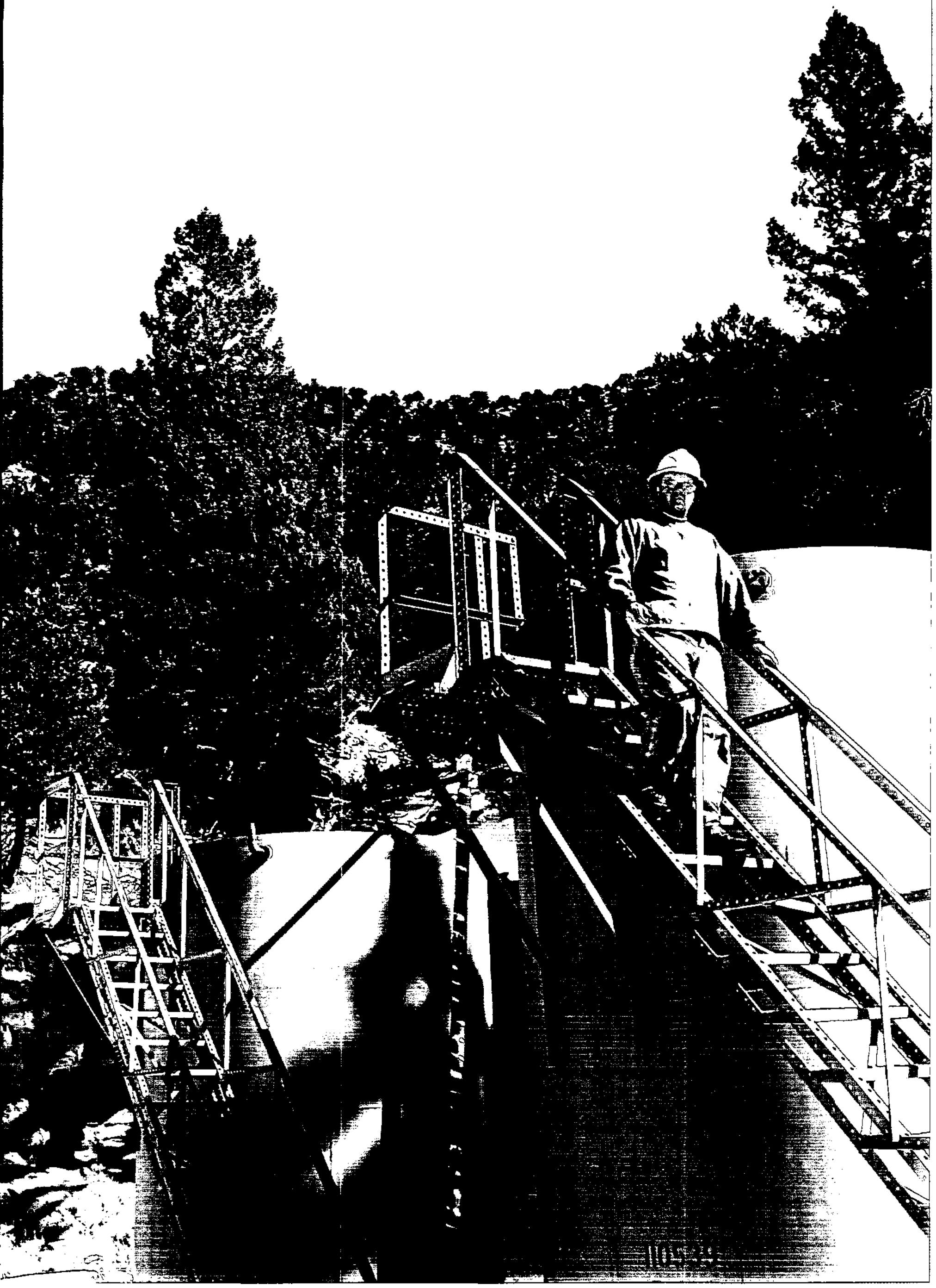
Our unique business model, incorporating a vertically integrated approach to our operations, is keeping us on the leading edge of CBM technology and has led to impressive operating results in the Raton Basin. Today, Evergreen ranks among the 25 largest natural gas companies, including the major integrated companies, in terms of domestic natural gas reserves.

In early 2001, we began an infill-drilling program in the Basin, in which we were adding a fifth well per square-mile section where four CBM wells were already producing. This program has not only accelerated production but has also generated new reserve additions. Based on the results of this initial infill drilling program, as well as strong prevailing natural gas prices, we are now drilling a sixth well per square-mile section in most of our development areas. These "sixth" wells are primarily rate-acceleration wells. As we continue development of the Basin, certain areas of our field may lend themselves to an even tighter drilling pattern.

Drilling to the Raton coal formation has generated particularly encouraging results. On our Cottontail Pass and Sangre de Cristo Federal Units, we are penetrating thicker Raton coal intervals with greater natural gas content and higher pressures than previously encountered in our Spanish Peaks Federal Unit to the southeast.

We have also encountered excellent production rates from the Basin's Raton sands, from which initial production rates can reach as high as 500 Mcfe per day. These wells have a more conventional production profile with high initial production rates and relatively steep decline curves and provide a nice complement to our inclining CBM natural gas production.

While we continue to see upside potential from a number of deeper plays in the Basin, we are focusing our near-term efforts on maximizing reserves and production from the Vermejo and Raton formations.

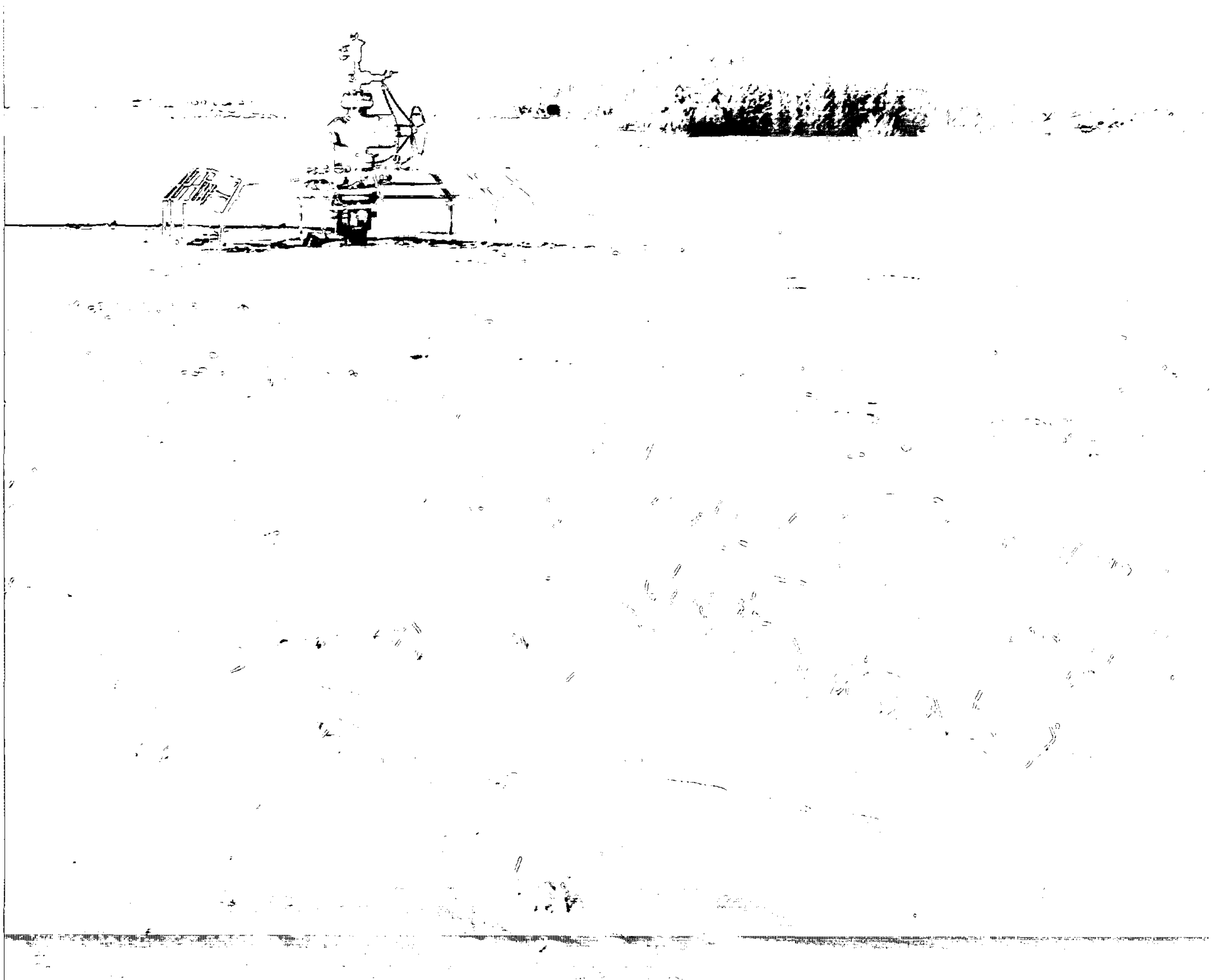


Our acquisition of properties in the Piceance and Uintah Basins provides us with additional core areas holding meaningful upside potential for unconventional natural gas reserves and production growth.

ACQUIRED PROPERTIES

Piceance and Uintah Basins
The properties we acquired in 2003 in the Piceance and Uintah Basins in western Colorado and eastern Utah are estimated to contain approximately 65 Bcfe of proven reserves, 51% of which are proved developed, as of December 31, 2003. There are currently 124 net wells producing at a daily net rate of 6.0 MMcfe of gas. Evergreen's gross acreage position in the Piceance and Uintah Basins is approximately 194,000 acres.

In 2004, we plan to drill a total of 55 wells in the Piceance and Uintah areas. Most of these planned wells will target conventional natural gas and tight gas sands at depths of between 4,500 feet and 7,500 feet. In the second half of the year, we expect to drill several wells to test the area's CBM potential at depths of approximately 1,500 feet. We also plan to install a new pipeline with a compressor station in order to alleviate pressure constraints from existing production and to connect shut-in and new gas production.



Western Canadian Sedimentary Basin

The acquisition of Carbon Energy provided Evergreen an entrée into the Western Canadian Sedimentary Basin in south-central Alberta, Canada, an area we believe holds significant potential for CBM development. These acquired properties were estimated to contain approximately 37 Bcfe of proven reserves, 72% of which are proved developed, at year-end 2003. Daily net production in early 2004 was averaging approximately 10.0 MMcfe of natural gas from 81 net wells. All of this production was coming from conventional natural gas wells and tight gas sand wells. Evergreen's gross acreage position in Western Canada was approximately 157,000 acres at year-end.

In the second half of 2004, we plan to begin a multi-well drilling program to test the area's CBM potential. These wells will target coal formations at depths ranging from 2,000 feet to 5,000 feet.

(L) Dave Sherman, Production Engineer, and Don Martin, Vice President of Exploration, Evergreen Resources Canada, Ltd. We believe the Western Canadian Sedimentary Basin offers highly attractive potential for CBM and conventional gas development.

EXPLORATORY PROJECTS

Forest City Basin

Evergreen holds a 100% working interest in more than 700,000 gross acres of prospective CBM properties in the Forest City Basin in eastern Kansas. Through year-end 2003, we drilled 18 CBM wells. The seven wells drilled to date in 2004 bring the total number of Evergreen CBM wells in the Forest City Basin to 25. Aggregate coal thicknesses have ranged from five feet to 40 feet per well, and 11 wells are currently in various stages of production testing. We plan to drill 61 wells in the Forest City Basin in 2004 and will evaluate the results of this initial drilling phase to determine additional well locations.

Alaska

In September 2003, we acquired the rights to an additional 230,000 acres of prospective CBM acreage in south-central Alaska. The majority of the new acreage is located immediately to the northwest of our acreage in the Pioneer Unit, extending about 25 miles up the Susitna River Valley. With the new properties, Evergreen's total leased acreage in south-central Alaska is approximately 300,000 acres.

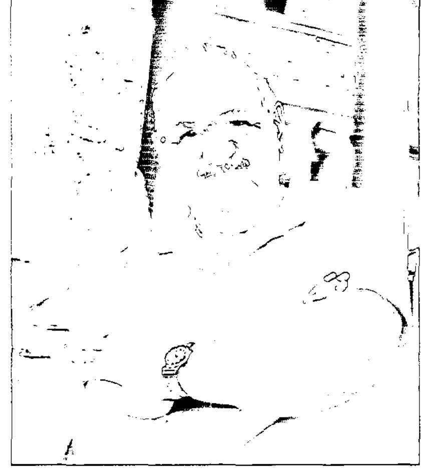
We are in the process of drilling five stratigraphic core holes on various parts of this acreage to obtain additional petrophysical data, including information on coal quality and gas content. Based on the results of these core holes, we will determine potential locations for additional core holes or multi-well pilots.

With more than 700,000 acres of prospective unconventional natural gas properties in the Forest City Basin in eastern Kansas, we have an excellent opportunity to apply our unique business model to establish an additional core area.

OUTLOOK FOR 2004

We plan to drill a total of 381 wells companywide in 2004, our most aggressive drilling year to date. Our net production target for year-end 2004 is 200 MMcfe of natural gas per day, which would equate to year-over-year production growth of approximately 37%.

COMMUNITY INVOLVEMENT



Our operations would not be possible without our community partnerships where we operate. From the day our operations began in the Raton Basin, Evergreen sought cooperative and mutually beneficial relationships with individual landowners, local governments and community outreach programs.

In 2003, Evergreen was recognized for our service and support when we were awarded the Colorado Oil & Gas Conservation Commission Community Relations Award for 2002. In that year we contributed to various organizations in Las Animas County, from the Red Cross to local fire departments.

Evergreen also was cited when we received the Employer Support Guard Reserves Award from the U.S. Department of Defense. We were recognized for continued support of an Evergreen employee while he was called to active duty with the National Guard.

In 2003, we continued our tradition of outreach to our Las Animas County constituents. We attempt to touch every citizen, either directly or indirectly, by assisting in a wide range of community projects.

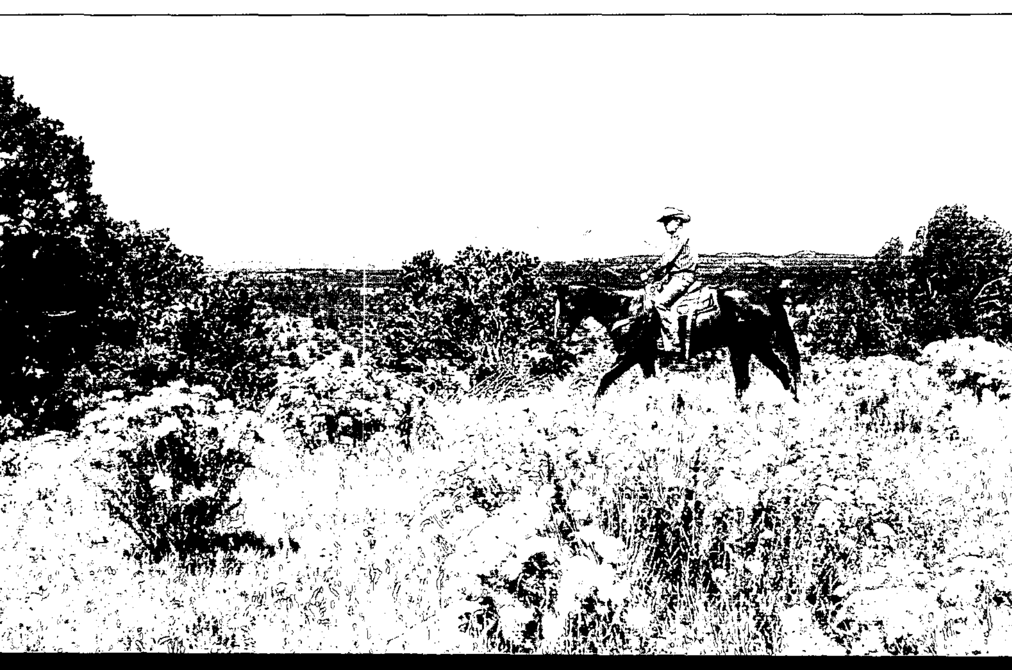
Wherever we have operations, our employees contribute in multiple activities. Evergreen supports local charities in Denver, Trinidad, Colorado and the Mat-Su Valley in Alaska. By standing with our employees, shareholders, landowners, neighbors and community leaders, we succeed and make a difference in all facets of our operations.

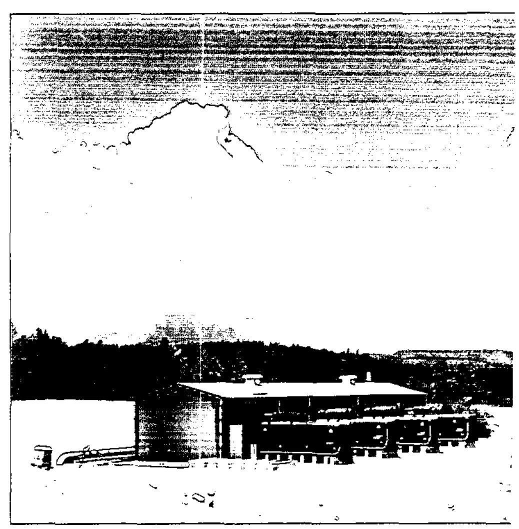
Of particular note is Evergreen's dedication to assisting low-income citizens with their energy bills. In 2003, we committed a total of $120,000 to the Colorado Energy Assistance Foundation for a three-year project to provide energy bill payment assistance and weatherization services to Las Animas County residents as part of Evergreen's natural gas supply contract with the city of Trinidad.

***(above)* Trinidad, Colorado Mayor Joe Reorda. At a ceremony commemorating Evergreen's donation to the Colorado Energy Assistance Foundation, Mayor Reorda commented, "If we would gather our resources, take a page out of Evergreen's book, and start helping each other, we would have a wonderful opportunity to help the best little town in the world."**

***(below left)* Building strong relationships with landowners is a priority for Evergreen. Doug Taylor rides the range on his family's 5,000-acre spread west of Trinidad.**

***(below)* Evergreen has a track record of taking the extra steps to mitigate the impact of its operations. The company relocated the Cottontail Pass Compressor Station to an unobtrusive area and enclosed the compressors with a sound-mitigating structure. Capacity was expanded to 15,000 horsepower.**





UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2003

or

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

For the transition period from to

Commission file number 0-13171

EVERGREEN RESOURCES, INC.
(Exact name of registrant as specified in its charter)

Colorado (State or other jurisdiction of incorporation or organization)	84-0834147 (I.R.S. Employer Identification No.)
1401 17th Street Suite 1200 Denver, Colorado (Address of principal executive offices)	80202 (Zip Code)

(303) 298-8100
Registrant's telephone number, including area code

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, no par value	New York Stock Exchange
Share Purchase Rights	New York Stock Exchange

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ 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 to this Form 10-K. ☐

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ☒ No ☐

As of January 31, 2004, the Registrant had 43,020,252 common shares outstanding. As of June 30, 2003, the aggregate market value of the common shares held by non-affiliates was approximately $1,011 million based upon the closing price of $27.16 per share (as adjusted to reflect Evergreen's two-for-one stock split effective September 16, 2003) for the common stock on June 30, 2003, as reported on the New York Stock Exchange.

DOCUMENTS INCORPORATED BY REFERENCE: DEFINITIVE PROXY MATERIALS FOR 2004 ANNUAL MEETING OF STOCKHOLDERS—PART III, ITEMS 10, 11, 12, 13 AND 14.

TABLE OF CONTENTS

		Page
	Part I	
Item 1.	Business	3
Item 2.	Properties	20
Item 3.	Legal Proceedings	27
Item 4.	Submission of Matters to a Vote of Security Holders	27
	Part II	
Item 5.	Market for Registrant's Common Equity and Related Stockholder Matters	28
Item 6.	Selected Financial Data	28
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	30
Item 7A.	Quantitative and Qualitative Disclosure About Market Risk	44
Item 8.	Financial Statements and Supplementary Data	45
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	45
Item 9A.	Controls and Procedures	45
	Part III	
Item 10.	Directors and Executive Officers of the Registrant	45
Item 11.	Executive Compensation	45
Item 12.	Security Ownership of Certain Beneficial Owners and Management	45
Item 13.	Certain Relationships and Related Transactions	45
Item 14.	Principal Accountant Fees and Services	45
	Part IV	
Item 15.	Exhibits, Financial Statement Schedules, and Reports on Form 8-K	46
Signatures		48

PART I

ITEM 1. BUSINESS

General

Evergreen Resources, Inc. ("Evergreen" or "the Company") was incorporated in Colorado on January 14, 1981. Evergreen is an independent energy company primarily engaged in the operation, development, production, exploration and acquisition of North American unconventional natural gas properties. Evergreen is one of the leading developers of coal bed methane reserves in the United States. Evergreen's operations are principally focused on developing and expanding its coal bed methane project located in the Raton Basin in southern Colorado. Evergreen has recently acquired producing properties in the Piceance Basin in western Colorado, the Uintah Basin in eastern Utah and the Western Canada Sedimentary Basin. The Company has gas production from tight sands and shales in these newly acquired areas that it intends to enhance. The Company is also evaluating the additional coal bed methane and other gas resource potential within each of these recently acquired basins. In addition, Evergreen has initiated coal bed methane projects in the Forest City Basin in eastern Kansas and the Cook Inlet-Susitna Basin in Alaska.

Evergreen maintains its principal executive offices at 1401 17th Street, Suite 1200, Denver, Colorado 80202; telephone (303) 298-8100. The Company's website is www.EvergreenGas.com. The Company makes available free of charge on its website its Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after such material is electronically filed with, or furnished to, the Securities and Exchange Commission ("SEC").

The authorized capitalization of the Company is 100,000,000 shares of no par value common stock, of which 42,936,587 shares were issued and outstanding at December 31, 2003, and 24,900,000 shares of $1.00 par value preferred stock, none of which were issued and outstanding at December 31, 2003.

This report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), including statements regarding, among other items, (1) the Company's growth strategies, (2) anticipated trends in the Company's business and its future results of operations, (3) market conditions in the oil and gas industry, (4) the ability of the Company to make and integrate acquisitions, (5) the outcome of litigation and the impact of governmental regulation, (6) financial market conditions, (7) wars and acts of terrorism or sabotage and (8) the risks associated with integration of acquired companies. These forward-looking statements are based largely on the Company's expectations and are subject to a number of risks and uncertainties, many of which are beyond the Company's control. Actual results could differ materially from those implied by these forward-looking statements as a result of, among other things, (1) a decline in oil and natural gas production, (2) a decline in oil and natural gas prices, (3) incorrect estimations of required capital expenditures, (4) increases in the cost of drilling, (5) completion and gas collection, (6) an increase in the cost of production and operations, (7) an inability to meet growth projections or (8) changes in general economic conditions. These and other risks are discussed under the heading "—Certain Risks." In light of these and other risks and uncertainties of which the Company may be unaware or which the Company currently deems immaterial, there can be no assurance that actual results will be as projected in the forward-looking statements.

For a discussion of the development of the Company's business, see "Item 2. Properties" and for a discussion of the oil and gas properties by geographic area, see Note 16 to the Consolidated Financial Statements.

Reference should be made to the Glossary of Oil and Natural Gas Terms at the end of this document.

Business Activities and Recent Developments

Raton Basin

The Company's current operations are principally focused on developing and expanding its coal bed methane project located in the Raton Basin in southern Colorado.

The Company is one of the largest holders of oil and gas leases in the Raton Basin. Evergreen holds interests in approximately 385,000 gross acres of coal bed methane properties in the Basin. At December 31, 2003, the Company had estimated net proved reserves in the Raton Basin of 1.4 Tcfe, 62% of which were proved developed, with a PV-10 of approximately $2.5 billion. The Company's net average daily gas sales from the Raton Basin for the month of December 2003 were approximately 131 MMcfe from a total of 973 net producing wells. Evergreen's Raton Basin drilling program has enabled the Company to build an extensive inventory of additional drilling locations. The Company has identified at least 1,000 additional drilling locations on its Raton Basin acreage, of which 468 were included in its estimated proved reserve base at December 31, 2003. The Company operates substantially all of its producing properties in the Raton Basin and holds working interests ranging from 75% to 100%.

Since Evergreen began its drilling efforts in the Raton Basin, the Company has drilled more than 800 wells and achieved a success rate of approximately 98%. In addition, the Company has acquired over 250 producing wells in the Raton Basin since the beginning of the Raton Basin project. From March 31, 1995 through December 31, 2003, Evergreen grew its estimated proved reserves from 58 Bcfe to 1,393 Bcfe, which represents a compound annual growth rate of approximately 44%. During the same period, the Company's net average daily gas sales increased from just over 1 MMcfe to approximately 131 MMcfe.

From the beginning of the Company's Raton Basin project through December 31, 2003, the Company has spent approximately $426 million on the drilling and completion of its wells, pipelines, gas collection systems and compression equipment, and $244 million on the acquisition of additional properties. This represents an estimated total finding and development cost of $0.36 per proved Mcfe excluding acquisitions and $0.45 per proved Mcfe including acquisitions.

Purchase of Carbon Energy Corporation

Evergreen completed the acquisition of Carbon Energy Corporation ("Carbon") on October 29, 2003. Carbon was an independent oil and gas company engaged in the exploration, development and production of oil and natural gas in the United States and Canada. Carbon's areas of operations in the United States were the Piceance Basin in Colorado and the Uintah Basin in Utah. Carbon's area of operations in Canada were in south-central Alberta.

Under the terms of the acquisition agreement, Carbon's shareholders received 0.55 shares of Evergreen common stock for each common share of Carbon. As a result, Evergreen issued approximately 3.5 million new shares of Evergreen common stock to Carbon's shareholders. The aggregate value of the transaction, including transaction costs, change in control payments and the fair value of Carbon employee stock options assumed by Evergreen was approximately $88.4 million. The net assets acquired included the assumption of Carbon's debt of approximately $20 million.

At the time of the acquisition, Carbon's net oil and gas reserves in the United States and Canada were estimated at approximately 59 Bcfe and 38 Bcfe, respectively, of which 45% and 73%, respectively, were classified as proved developed and the remaining amounts were classified as proved undeveloped. Independent petroleum engineering consultants Netherland Sewell & Associates, Inc. prepared the reserve estimates of Carbon. Average daily net production in the United States and Canada during the month of December 2003 was approximately 13.4 MMcfe. The gross acreage position acquired in connection with the Carbon acquisition was approximately 150,000 acres in the United States and 130,000 acres in Canada.

Kansas

During 2002 and 2003, Evergreen acquired in excess of 700,000 gross acres of prospective unconventional natural gas properties in the Forest City Basin in eastern Kansas. The Company drilled and completed 18 coal bed methane wells and three water disposal wells in the Forest City Basin in the fourth quarter of 2003. Evergreen holds a 100% working interest in the Kansas acreage. The acreage generally lies in the Forest City Basin and also contains shallow gas potential from coals, fractured shales and sands. Management has recently decided to pursue a more moderate exploration and development program in the Forest City Basin in 2004 than was earlier anticipated.

Alaska

Evergreen holds approximately 300,000 gross acres of prospective coal bed methane acreage in south-central Alaska. The acreage is located in the Cook Inlet-Susitna Basin approximately 30 miles north of Anchorage. Early in the second quarter of 2003, Evergreen completed five of its eight coal bed methane wells on the Pioneer Unit in Alaska's Cook Inlet-Susitna Basin. The initial production results indicate that the wells in these first two pilot projects are not capable of commercial production. In December 2003, the Company drilled the first of five planned stratigraphic core holes on various parts of its acreage base in Alaska to obtain additional petrophysical data, including information on coal quality and gas content. Based on the results of these core holes, the Company will determine potential locations in 2004 for additional core holes or multi-well pilots.

Customers and Markets

Gas Marketing and Transportation

Primero Gas Marketing Company ("Primero") is a wholly owned subsidiary of the Company that was formed to market and sell natural gas for the Company and third parties. To date, Primero has marketed and sold gas only on behalf of the Company and its royalty interest and working interest partners. Primero operates the Company's gas collection system in the Raton Basin and purchases all of the Company's production from its Raton Basin wells.

The Company sells its oil and natural gas on an index basis to creditworthy companies including utilities, other end users and energy marketing companies. Natural gas production from the Raton Basin is sold into the Mid-Continent markets by use of firm transportation contracts with Colorado Interstate Gas Company. Natural gas production from the Piceance and Uintah Basins is generally sold at prices based on the regional price set by the market place for natural gas deliveries to the interstate mainline transportation pipeline in the region, which is generally Northwest Pipeline Corp. Natural gas production from the Western Canada Sedimentary Basin is generally sold at prices based on the market price for natural gas deliveries to the Alberta Energy Company, Ltd. ("AECO") pipeline.

In the United States, oil and natural gas liquids are sold under contracts extending up to a year based upon monthly refiner price postings, which generally approximate the price of West Texas Intermediate for crude oil and Applicable Conway, Kansas posting for natural gas liquids, adjusted to reflect transportation costs and quality. In Canada, oil and natural gas liquids are sold under short-term contracts at refiner posted prices for Alberta and Saskatchewan, adjusted to reflect transportation costs and quality. The Company's oil and natural gas liquids are sold at spot market prices or under short-term contracts.

The Company also periodically enters into commodity derivative contracts to hedge its production when market conditions are deemed favorable in order to manage price fluctuations and achieve a more predictable cash flow.

Current gross gas sales from the Raton Basin total approximately 240 MMcf per day. Evergreen's gross sales represent approximately 64% of the Raton Basin total. Takeaway capacity on the Colorado Interstate Gas Company system from the Raton Basin is currently estimated at 290 MMcf per day. The Company expects that, based on Evergreen's projected production growth and other operators projected growth, Colorado Interstate Gas Company will have to expand the takeaway capacity in the future. Colorado Interstate Gas Company is expected to expand the takeaway capacity to 400 MMcf per day.

The Company's current firm transportation commitments are 127 MMcf of gross sales per day plus additional availability of firm transportation. The Company expects that it will be required to commit to additional firm transportation for Colorado Interstate Gas Company to expand takeaway capacity.

Major Customers

Evergreen has three customers that represented in excess of 10% of the Company's total sales during 2003 which purchased approximately 24%, 15% and 14% of the Company's natural gas production for the year ended December 31, 2003. Based on the general demand for oil and natural gas, the Company does not believe that a loss of any or all of these customers would have a material adverse effect on Evergreen's business.

Competition

The Company competes in virtually all facets of its business with numerous other companies, including many that have significantly greater resources. Such competitors may be able to pay more for desirable leases and to evaluate, bid for and purchase a greater number of properties than the financial or personnel resources of the Company permit. The ability of the Company to increase reserves in the future will be dependent on its ability to select and acquire suitable producing properties and prospects for future exploration and development. The availability of a market for oil and natural gas production depends upon numerous factors beyond the control of producers, including but not limited to the availability of other domestic or imported production, the locations and capacity of pipelines and the effect of federal, state, provincial and local regulation on such production.

Government Regulation of the Oil and Gas Industry

General

The Company's business is affected by numerous laws and regulations, including, among others, laws and regulations relating to energy, environment, conservation and tax. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and/or criminal penalties, the imposition of injunctive relief or both. Moreover, changes in any of these laws and regulations could have a material adverse effect on the Company's business. In view of the many uncertainties with respect to current and future laws and regulations, including their applicability to the Company, the Company cannot predict the overall effect of such laws and regulations on its future operations.

The Company believes that its operations comply in all material respects with applicable laws and regulations and that the existence and enforcement of such laws and regulations have no more restrictive effect on the Company's method of operations than on other similar companies in the energy industry.

The following discussion contains summaries of certain laws and regulations and is qualified in its entirety by the foregoing.

Federal Regulation of the Sale and Transportation of Oil and Gas

Various aspects of the Company's oil and natural gas operations are regulated by agencies of the federal government. The Federal Energy Regulatory Commission ("FERC") regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 ("NGA") and the Natural Gas Policy Act of 1978 ("NGPA"). In the past, the federal government has regulated the prices at which oil and gas could be sold. While "first sales" by producers of natural gas and all sales of crude oil, condensate and natural gas liquids can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead sales in the natural gas industry began with the enactment of the NGPA in 1978. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act (the "Decontrol Act"). The Decontrol Act removed all NGA and NGPA price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

Commencing in April 1992, the FERC issued Orders Nos. 636, 636-A, 636-B, 636-C and 636-D ("Order No. 636"), which require interstate pipelines to provide transportation services separate, or "unbundled," from the pipelines' sales of gas. Also, Order No. 636 requires pipelines to provide open access transportation on a nondiscriminatory basis that is equal for all natural gas shippers. Although Order No. 636 does not directly regulate the Company's production activities, the FERC has stated that it intends for Order No. 636 to foster increased competition within all phases of the natural gas industry. It is unclear what impact, if any, increased competition within the natural gas industry under Order No. 636 will have on the Company's activities.

The courts have largely affirmed the significant features of Order No. 636 and numerous related orders pertaining to the individual pipelines, although certain appeals remain pending and the FERC continues to review and modify its open access regulations. In particular, the FERC is conducting a broad review of its transportation regulations, including how they operate in conjunction with state proposals for retail gas marketing restructuring, whether to eliminate cost-of-service rates for short-term transportation, whether to allocate all short-term capacity on the basis of competitive auctions, and whether changes to long-term transportation policies may also be appropriate to avoid a market bias toward short-term contracts. In February 2000, the FERC issued Order No. 637 amending certain regulations governing interstate natural gas pipeline companies in response to the development of more competitive markets for natural gas and natural gas transportation. The goal of Order No. 637 is to "fine tune" the open access regulations implemented by Order No. 636 and to accommodate subsequent changes in the market. Key provisions of Order No. 637 include: (1) permitting value-oriented peak/off peak rates to better allocate revenue responsibility between short-term and long-term markets; (2) permitting term-differentiated rates, in order to better allocate risks between shippers and the pipeline; (3) revising the regulations related to scheduling procedures, capacity, segmentation, imbalance management, and penalties; (4) retaining the right of first refusal ("ROFR") and the five-year matching cap for long-term shippers at maximum rates, but significantly narrowing the ROFR for customers that the FERC does not deem to be captive; and (5) adopting new website reporting requirements that include daily transactional data on all firm and interruptible contracts and daily reporting of scheduled quantities at points or segments. Most major aspects of Order No. 637 were upheld on judicial review, though certain issues, such as capacity segmentation and rights of first refusal, were remanded to the FERC, which issued a remand order in October of 2002. In January of 2004, the FERC denied rehearing of its October 2002 remand order. The Company cannot predict whether judicial review will be sought of the FERC's remand order and, if so, whether and to what extent FERC's market reforms will survive such review and, if they do, whether the FERC's actions will achieve the goal of increasing competition in markets in which the Company's natural gas is sold. However, the Company does not believe that it will be affected by any action taken materially differently than other natural gas producers and marketers with which it competes.

Commencing in October 1993, the FERC issued a series of rules (Order Nos. 561 and 561-A) establishing an indexing system under which oil pipelines will be able to change their transportation rates, subject to prescribed ceiling levels. The indexing system, which allows pipelines to make rate changes to track changes in the Producer Price Index for Finished Goods, minus one percent, became effective January 1, 1995. The Company does not believe that these rules affect the Company any differently than other oil producers and marketers with which it competes.

The FERC has also issued numerous orders confirming the sale and abandonment of natural gas gathering facilities previously owned by interstate pipelines and acknowledging that if the FERC does not have jurisdiction over services provided thereon, then such facilities and services may be subject to regulation by state authorities in accordance with state law. A number of states have either enacted new laws or are considering the adequacy of existing laws affecting gathering rates and/or services.

Other state regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, nondiscriminatory take requirements, but does not generally entail rate regulation. Thus, natural gas gathering may receive greater regulatory scrutiny of state agencies in the future. The Company's gathering operations could be adversely affected should they be subject in the future to increased state regulation of rates or services, although the Company does not believe that it would be affected by such regulation any differently than other natural gas producers or gatherers. In addition, the FERC's approval of transfers of previously regulated gathering systems to independent or pipeline affiliated gathering companies that are not subject to FERC regulation may affect competition for gathering or natural gas marketing services in areas served by those systems and thus may affect both the costs and the nature of gathering services that may be available to interested producers or shippers in the future.

The Company owns certain natural gas pipeline facilities that it believes meet the traditional tests the FERC has used to establish a pipeline's status as a gatherer not subject to the FERC's jurisdiction. Whether on state or federal land, natural gas gathering may receive greater regulatory scrutiny in the post-Order No. 636 environment.

The Company conducts certain operations on federal oil and gas leases, which are administered by the Minerals Management Service ("MMS"). Federal leases contain relatively standard terms and require compliance with detailed MMS regulations and orders, which are subject to change. Among other restrictions, the MMS has regulations restricting the flaring or venting of natural gas, and the MMS has proposed to amend such regulations to prohibit the flaring of liquid hydrocarbons and oil without prior authorization. Under certain circumstances, the MMS may require any company operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect the Company's financial condition, cash flows and operations. The MMS issued a final rule that amended its regulations governing the valuation of crude oil produced from federal leases. This rule, which became effective June 1, 2000, provides that the MMS will collect royalties based on the market value of oil produced from federal leases. On August 20, 2003, the MMS issued a proposed rule that would change certain components of its valuation procedures for the calculation of royalties owed for crude oil sales. The proposed changes included changing the valuation basis for transactions not at arm's-length from spot to NYMEX prices adjusted for locality and quality differentials, and clarifying the treatment of transactions under a joint operating agreement. Final comments on the proposed rule were due on November 10, 2003. The Company has no way of knowing whether the MMS will implement the proposed changes in a final rule or what effect such changes, if implemented, will have on the Company's results of operations, However, the Company does not believe that this proposed rule would affect it any differently than other producers and marketers of crude oil.

Additional proposals and proceedings that might affect the oil and gas industry are pending before Congress, the FERC, the MMS, state commissions and the courts. The Company cannot predict when or whether any such proposals and proceedings may become effective. In the past, the natural gas industry has been heavily regulated. There is no assurance that the regulatory approach currently pursued by various agencies will continue indefinitely. Notwithstanding the foregoing, the Company does not anticipate that compliance with existing federal, state and local laws, rules and regulations will have a material or significantly adverse effect upon the capital expenditures, earnings or competitive position of the Company or its subsidiaries. No material portion of Evergreen's business is subject to re-negotiation of profits or termination of contracts or subcontracts at the election of the federal government.

Bureau of Land Management

Of the Company's Raton Basin acreage, approximately 138,000 gross acres are held within three federal units that the Company operates and that are administered by the Bureau of Land Management ("BLM"). See "Item 2. Properties—Raton Basin Properties and Operations." Of the

Company's Piceance and Uintah Basins acreage, approximately 20,000 gross acres are held within nine federal units that the Company operates. Inclusion of property within a unit simplifies lease maintenance for the Company and promotes orderly development.

The BLM controls isolated parcels of federally owned surface and/or minerals in the Raton Basin in southern Colorado. The BLM controls a larger portion of the acreage within the Piceance Basin in northwestern Colorado and the Uintah Basin in northeastern Utah. Drilling and development of federal minerals and construction activities on federal surface are subject to the National Environmental Policy Act ("NEPA"). BLM has completed an environmental assessment under NEPA. To date, 28 wells have been drilled on BLM minerals in the Raton Basin and 143 wells in the Piceance and Uintah Basins. In the Raton Basin, the BLM has completed an environmental assessment, and all future wells are expected to be approved based on the results of the environmental assessment. Development of adjacent fee lands and minerals within the Raton Basin has proceeded unhindered and access to fee lands has not been hindered by the presence of isolated parcels of federal surface. Future activities within the Piceance and Uintah Basins will be subject to NEPA. The scope and effect are not known at the present time. The number of proposed wells on BLM minerals represents approximately 3% of the total number of wells Evergreen has planned to drill in the Raton Basin and over 90% of the total number of wells Evergreen has planned to drill in the Piceance and Uintah Basins during 2004.

State Regulations

The Company's operations are also subject to regulation at the state level and, in some cases, county, municipal and local governmental levels. Such regulation includes (1) requiring permits for the drilling of wells, (2) maintaining bonding requirements in order to drill or operate wells and (3) regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used and produced in connection with operations. The Company's operations are also subject to various conservation laws and regulations. These include (1) proration units, (2) the density of wells that may be drilled, and (3) the unitization or pooling of oil and gas properties. In addition, state conservation laws establish maximum rates of production from oil and gas wells, which generally limit the venting or flaring of gas and impose certain requirements regarding the ratability of production. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, but (except as noted above) does not generally entail rate regulation. These regulatory burdens may affect profitability, and the Company is unable to predict the future cost or impact of complying with such regulations.

Canadian Regulations

The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. Federal authorities do not regulate the price of oil and gas in export trade but instead rely on market forces to establish these prices. Legislation exists that regulates the quantities of oil and natural gas which may be removed from the provinces and exported from Canada. The Company does not expect that any of these controls and regulations will affect the Company in a manner significantly different than other oil and natural gas companies of similar size.

The provinces in which the Company operates have legislation and regulation which govern land tenure, royalties, production rates and environmental protection. The royalty regime in the provinces in which the Company operates is a significant factor in the profitability of the Company's production. Crown royalties are determined by government regulation and are typically calculated as a percentage of the value of production. The value of the production and the rate of royalties payable depends on prescribed reference prices, well productivity, geographical location and the type or quality of the product produced.

In Alberta, the Company is entitled to a credit against Crown royalties on most of the properties in which the Company has an interest by virtue of the Alberta Royalty Tax Credit. The credit is determined by applying a rate to a maximum of CDN $2.0 million of Crown royalties payable in Alberta for each company or associated group of companies. The rate is a function of the royalty tax credit par prices which is determined quarterly by the Alberta Department of Energy. The rate ranges from 25% to 75% depending upon petroleum prices for the previous quarter.

Environmental Matters

The Company is subject to extensive federal, foreign, state, provincial and local environmental laws and regulations that, among other things, regulate the discharge or disposal of substances into the environment and otherwise are intended to protect the environment. Numerous governmental agencies issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial administrative, civil and/or criminal penalties and, in some cases, injunctive relief for failure to comply. Some laws and regulations relating to the protection of the environment may, in certain circumstances, impose "strict liability" for environmental contamination. Such laws and regulations render a person or company liable for environmental and natural resource damages, cleanup costs and, in the case of oil spills in certain states, consequential damages without regard to negligence or fault. Other laws and regulations may require the rate of oil and natural gas production to be below the economically optimal rate or may even restrict or prohibit exploration or production activities in environmentally sensitive areas. In addition, state laws often require some form of remedial action such as closure of inactive pits and plugging of abandoned wells to prevent pollution from former or suspended operations. Moreover, from time to time, legislation or other initiatives are proposed to Congress or to state and local governments that would place more onerous conditions on the treatment, storage, disposal or clean-up of certain oil and gas exploration and production wastes. If such legislation or other initiatives were to be enacted or adopted, it could have an adverse impact on the operating costs of the Company, as well as the oil and gas industry in general. The regulatory burden on the oil and natural gas industry increases the Company's cost and risk of doing business and consequently affects its profitability.

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

The Company currently owns or leases, and has in the past owned or leased, numerous properties that have long been used for oil and gas exploration and production. Although the Company has utilized operating and disposal practices that were standard for the industry at the time, substances in the past have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where such substances have been taken or placed for disposal. In addition, many of these properties have from time to time been operated by third parties whose management of substances was not under the Company's control. These properties and the substances disposed thereon may be subject to CERCLA, the Resource Conservation and Recovery Act, as amended, and analogous state laws and regulations. Under such laws and regulations, the Company could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or pit closure operations to prevent future contamination. The Company is currently planning to perform remedial closures on three pits formerly operated by it in Huerfano County, Colorado, as well as on 40 to 50 pits formerly operated by Carbon in the Piceance and Uintah Basins. The Company believes that only soils are impacted beneath these pits and that they may be closed at a collective cost of less than $300,000 over the next year.

In connection with the Company's coal bed methane gas production, the Company from time to time conducts production enhancement techniques, including various activities designed to induce hydraulic fracturing of the coal bed. While the Company performs its production enhancement techniques in substantial compliance with the requirements set forth by the State of Colorado, neither Colorado nor the federal Environmental Protection Agency ("EPA") regulates this coal bed formation hydraulic fracturing as a form of underground injection. It is possible that hydraulic fracturing of coal beds for methane gas production will become regulated within the United States as a form of underground injection, resulting in the imposition of stricter performance standards (which, if not met, could result in diminished opportunities for methane gas production enhancement) and increased administrative and operating costs for the Company. Evergreen's management cannot predict whether potential future regulation of hydraulic fracturing as a form of underground injection would have an adverse material effect on the Company's operations or financial position. However, such regulation is not expected to be any more burdensome to the Company than it would be to other similarly situated companies involved in coal bed methane gas production or tight gas sands production within the United States.

In the Company's coal bed methane gas production, the Company typically brings naturally occurring groundwater to the surface as a by-product of the production of methane gas. This "produced water" is either re-injected into the subsurface or stored or disposed of in evaporation ponds or permitted natural collection features located on the surface at or near the well-site in compliance with federal and state statutes and regulations. In some cases, the produced water is used for stock watering, agricultural or dust suppression purposes, also in substantial compliance with federal, state and local laws and regulations. Under the Federal Water Pollution Control Act (also referred to as the "Clean Water Act") and various other state requirements and regulations, the EPA and the State of Colorado's Department of Public Health and the Environment assert administrative and regulatory enforcement authority over the discharge of produced water. Where the Company can meet federal and state regulatory requirements and applicable water quality standards, disposal of produced water by discharge to surface water is an option.

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

The Company's operations involve the use of gas-fired compressors to transport collected gas; these compressors are subject to federal and state regulations for the control of air emissions. The Company has obtained construction permits for additional compression in excess of current needs in anticipation of increased production from the Raton Basin. However, in the future, additional facilities could become subject to additional monitoring and pollution control requirements as compressor facilities are expanded.

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

At this time, the Company is not required and otherwise has no plans to make any material capital expenditures to install pollution control devices at facilities. However, the Company is currently evaluating options for reducing the level of noise at two compressor stations in the Raton Basin. The estimated cost for addressing this matter could be as high as $500,000, depending on the work actually performed.

In Canada, the oil and natural gas industry is currently subject to environmental regulations pursuant to provincial and federal legislation. Environmental legislation provides for restrictions on releases or emissions of various substances produced or utilized in association with certain oil and gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such regulations may result in the imposition of fines and penalties, the suspension of operations and potential civil liability. The Alberta Environmental Protection and Enhancement Act imposes environmental standards and requires compliance with various legislative criteria in Alberta, including reporting and monitoring requirements. The Alberta Energy and Utility Board, pursuant to its governing legislation, also plays a role with respect to the regulation of environmental impacts of oil and gas activities.

Title to Properties

As is customary in the oil and gas industry, only a preliminary title examination is conducted at the time the Company acquires leases of properties believed to be suitable for drilling operations. Prior to the commencement of drilling operations, a thorough title examination of the drill site tract is conducted by independent attorneys. Once production from a given well is established, the Company prepares a division order title report indicating the proper parties and percentages for payment of production proceeds, including royalties. The Company believes that the titles to its leasehold properties are good and defensible in accordance with standards generally acceptable in the oil and gas industry.

Employees

At January 31, 2004, the Company had 354 full-time employees.

Certain Risks

Oil and gas prices are volatile, and an extended decline in prices would hurt the Company's profitability and financial condition.

Evergreen's management expects the markets for oil and gas to continue to be volatile. Any substantial or extended decline in the price of oil or gas would negatively affect the Company's financial condition and results of operations. Evergreen's revenues, operating results, profitability, future rate of growth and the carrying value of its oil and gas properties depend heavily on prevailing market prices for oil and gas. A material decline could reduce the Company's cash flow and borrowing capacity, as well as the value and the amount of its oil and gas reserves. Substantially all of Evergreen's proved reserves are natural gas. Therefore, the Company is more directly impacted by volatility in the price of natural gas. Various factors beyond the Company's control can affect prices of oil and gas. These factors include:

- worldwide and domestic supplies of oil and gas;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil or gas producing regions;
- the price and level of foreign imports;
- worldwide economic conditions;
- marketability of production;
- the level of consumer demand;
- the price, availability and acceptance of alternative fuels;
- the availability of pipeline capacity;
- weather conditions; and
- actions of federal, foreign, state, provincial and local authorities.

These external factors and the volatile nature of the energy markets make it difficult to estimate future commodity prices.

In addition, the Company may be required to write down or impair the carrying value of the Company's oil and gas properties when oil and gas prices are depressed or unusually volatile. If a write-down is required, it would result in a charge to earnings and book value. Once incurred, a write-down of oil and gas properties is not reversible at a later date. The Company reviews, on a quarterly basis, the carrying value of its oil and gas properties under the full cost accounting rules of the SEC. Under these rules, capitalized costs of proved oil and gas properties, as adjusted for estimated asset retirement obligations, may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10%. Application of the ceiling test generally requires pricing future revenue at the unescalated prices in effect as of the end of each fiscal quarter, after giving effect to the Company's cash flow hedge positions, and requires a write-down for accounting purposes if the ceiling is exceeded, even if prices were depressed for only a short period of time.

The Company's operations require large amounts of capital that may not be recovered.

If the Company's revenues were to decrease due to lower oil and natural gas prices, decreased production or other reasons, and if it could not obtain capital through its credit facilities or otherwise, the Company's ability to execute its development plans, replace its reserves or maintain its production levels could be greatly limited. Evergreen's current development plans will require it to make large capital expenditures for the exploration and development of its oil and natural gas properties.

Historically, Evergreen has funded its capital expenditures through a combination of funds generated internally from sales of production or properties, the issuance of equity, long-term debt financing and short-term financing arrangements. Additional financing may not be available to the Company on acceptable terms. Future cash flows and the availability of financing will be subject to a number of variables, such as:

- the success of the Company's projects in the Raton, Piceance, Uintah and Western Canada Sedimentary Basins;
- the Company's success in locating and producing new reserves;
- the level of production from existing wells; and
- the prices of oil and natural gas.

Issuing equity securities to satisfy the Company's financing requirements could cause substantial dilution to existing stockholders. In addition, debt financing could lead to a diversion of cash flow to satisfy debt servicing obligations and restrictions on the Company's operations.

Information concerning the Company's reserves and future net revenue estimates is uncertain.

Evergreen's SEC filings contain estimates of its proved oil and gas reserves and the estimated future net revenues from such reserves. Actual results will likely vary from amounts estimated, and any significant variance could have a material adverse effect on the Company's future results of operations.

Reserve estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Furthermore, different reserve engineers may make different estimates of reserves and cash flow based on the same available data. Therefore, these estimates are not precise.

Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves disclosed by the Company. In addition, the Company may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond the Company's control.

At December 31, 2003, approximately 38% of the Company's estimated proved reserves were proved undeveloped. Estimation of proved undeveloped reserves and proved developed non-producing reserves is nearly always based on volumetric calculations rather than the performance data used to estimate producing reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Production revenues from proved developed non-producing reserves will not be realized until some time in the future. The reserve data assumes that Evergreen will make significant capital expenditures to develop its reserves. Although the Company has prepared estimates of its reserves and the costs associated with these reserves in accordance with industry standards, these estimated costs may not be accurate, development may not occur as scheduled and actual results may not be as estimated.

Analysts and investors should not construe the present value of future net reserves, or PV-10, as the current market value of the estimated oil and natural gas reserves attributable to the Company's properties. The Company's management has based the estimated discounted future net cash flows from proved reserves on prices and costs as of the date of the estimate, in accordance with applicable regulations, whereas actual future prices and costs may be materially higher or lower. Many factors will affect actual future net cash flows, including:

- the amount and timing of actual production;
- the supply and demand for oil and natural gas;

- curtailments or increases in consumption by natural gas purchasers; and
- changes in governmental regulations or taxation.

The timing of the production of oil and natural gas properties and of the related expenses affect the timing of actual future net cash flows from proved reserves and, thus, their actual present value. In addition, the 10% discount factor, which the Company is required to use to calculate PV-10 for reporting purposes, is not necessarily the most appropriate discount factor given actual interest rates and risks to which the Company's business or the oil and natural gas industry in general are subject.

The Company's exploratory and development drilling activities may not be successful.

The Company's future drilling activities may not be successful, and the Company's management cannot be sure that the Company's overall drilling success rate or the Company's drilling success rate for activity within a particular area will not decline. In addition, the wells that the Company drills may not recover all or any portion of the Company's capital investment in the wells, infrastructure or the underlying leaseholds. The Company is currently in the early stages of various exploration projects throughout the United States and Canada and the Company can offer no assurance that the development of these projects will occur as scheduled or that actual results will be in line with the Company's initial estimates. Unsuccessful drilling activities could negatively affect the Company's results of operations and financial condition. The cost of drilling, completing and operating wells is often uncertain, and a number of factors can delay or prevent drilling operations, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- ability to hire and train personnel for drilling and completion services;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment.

In addition, Evergreen may not be able to obtain any options or lease rights in potential drilling locations that it identifies. There is no guarantee that the potential drilling locations that the Company has identified will ever produce oil or natural gas.

The Company's acquisition activities may not be successful.

As part of the Company's growth strategy, the Company may make additional acquisitions of businesses and properties. However, suitable acquisition candidates may not be available on terms and conditions it finds acceptable, and acquisitions pose substantial risks to the Company's business, financial condition and results of operations. In pursuing acquisitions, the Company competes with other companies, many of which have greater financial and other resources to acquire attractive companies and properties. Even if future acquisitions are completed, the following are some of the risks associated with acquisitions:

- the acquired businesses or properties may not produce revenues, earnings or cash flow at anticipated levels;
- the Company may assume liabilities that were not disclosed or that exceed the Company's estimates;
- the Company may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems;
- acquisitions could disrupt the Company's ongoing business, distract management, divert resources and make it difficult to maintain the Company's current business standards, controls and procedures;
- the Company may finance future acquisitions by issuing common stock for some or all of the purchase price, which could dilute the ownership interests of the Company's stockholders; and
- the Company may incur additional debt related to future acquisitions.

The Company faces risks inherent in expanding its operations into Canada.

As a result of the Company's acquisition of Carbon in 2003, it acquired Carbon's working interests in Alberta, Canada. These international operations may be adversely affected by currency fluctuations. The revenues and expenses of such operations are denominated in Canadian dollars. As a result, the Company's Canadian operations are subject to risk of fluctuations in the relative value of the Canadian and United States dollars.

The Company may be affected by the gas prices in the Rocky Mountain region.

As a result of the acquisition of Carbon in 2003, the Company acquired Carbon's working interests in the Piceance Basin in Colorado and the Uintah Basin in Utah. The prices to be received by the Company for the natural gas production from these properties will be determined mainly by factors affecting the regional supply of and demand for natural gas. Based on recent experience, regional differences could cause a negative basis differential between the published indices generally used to establish the price received for regional natural gas production and the actual price received by the Company for its natural gas production.

The Company faces strong competition in the oil and gas industry, and many of its competitors have greater resources than Evergreen.

The Company operates in a highly competitive industry. The Company competes with major oil companies, independent producers and institutional and individual investors, which are actively seeking oil and gas properties throughout the world, along with the equipment, labor and materials required to operate properties. Many of the Company's competitors have financial and technological resources vastly exceeding those available to Evergreen. Many oil and gas properties are sold in a competitive bidding process in which the Company may lack the technological information or expertise available to other bidders. The Company can offer no assurance that it will be successful in acquiring and developing profitable properties in the face of this competition.

The Company's operations are subject to the business and financial risk of oil and gas exploration.

The business of exploring for and, to a lesser extent, developing oil and gas properties is an activity that involves a high degree of business and financial risk. Property acquisition decisions generally are based on various assumptions and subjective judgments that are speculative. It is impossible to predict accurately the ultimate production potential, if any, of a particular property or well. Moreover, the successful completion of an oil or gas well does not ensure a profit on investment. A variety of factors, both geological and market-related, can cause a well to become uneconomic or marginally economic.

The Company's business is subject to operating hazards that could result in substantial losses.

The oil and natural gas business involves operating hazards such as well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, formations with abnormal pressures, pipeline ruptures or spills, pollution, releases of toxic gas and other environmental hazards and risks, any of which could cause the Company a substantial loss. In addition, the Company may be held liable for environmental damage caused by previous owners of property it owns or leases. As a result, the Company may face substantial liabilities to third parties or governmental entities, which could reduce or eliminate funds available for exploration, development or acquisitions or cause Evergreen to incur losses. An event that is not fully covered by insurance—for example, losses resulting from pollution and environmental risks, which are not fully insurable—could have a material adverse effect on the Company's financial condition and results of operations.

Hedging transactions may limit the Company's potential gains or expose the Company to loss.

To manage Evergreen's exposure to price risks in the marketing of its natural gas, the Company enters into natural gas fixed-price physical delivery contracts as well as derivative contracts from time to time with respect to a portion of its current or future production. These transactions may limit the Company's potential gains if natural gas prices were to rise substantially over the price established by the contracts. In addition, such transactions may expose Evergreen to the risk of financial loss in certain circumstances, including instances in which:

- the Company's production is less than expected;
- there is a widening of price differentials between delivery points for the Company's production and the delivery point assumed in the hedge arrangements;
- the counterparties to the Company's futures contracts fail to perform the contracts; and
- a sudden, unexpected event materially impacts natural gas prices.

The Company may face unanticipated water disposal costs.

Where groundwater produced from Evergreen's coal bed methane projects fails to meet the quality requirements of applicable regulatory agencies or Evergreen's wells produce water in excess of the applicable volumetric permit limit, the Company may have to drill additional disposal wells to re-inject the produced water back into deep underground rock formations. The costs to dispose of this produced water may increase if any of the following occur:

- Evergreen cannot obtain future permits from applicable regulatory agencies;
- water of lesser quality is produced;
- Evergreen's wells produce excess water; or
- new laws or regulations require water to be disposed of in a different manner.

The Company has limited protection for its technology and depends on technology owned by others.

The Company uses operating practices that management believes are of significant value in developing coal bed methane resources. In most cases, patent or other intellectual property protection is unavailable for this technology. The Company's use of independent contractors in most aspects of its drilling and some completion operations makes the protection of such technology more difficult. Moreover, the Company relies on the technological expertise of the independent contractors that it retains for its oil and gas operations. The Company has no long-term agreements with these contractors, and management cannot be sure that the Company will continue to have access to this expertise.

The Company must comply with complex federal, foreign, state, provincial and local laws and regulations.

Federal, foreign, state, provincial and local authorities extensively regulate the oil and gas industry. Noncompliance with these statutes and regulations may lead to substantial penalties, and the overall regulatory burden on the industry increases the cost of doing business and, in turn, decreases profitability. Regulations affect various aspects of oil and gas drilling and production activities, including the pricing and marketing of oil and gas production, the drilling of wells (through permit and bonding requirements), the positioning of wells, the unitization or pooling of oil and gas properties, environmental matters, safety standards, the sharing of markets, production limitations, plugging and abandonment and restoration. These laws and regulations are under constant review for amendment or expansion.

The Company may incur substantial costs to comply with stringent environmental regulations.

The Company's operations are subject to stringent and constantly changing environmental laws and regulations adopted by federal, foreign, state, provincial and local governmental authorities. The Company could be forced to expend significant resources to comply with new laws or regulations, or changes to current requirements. Governmental environmental agencies have relatively little experience with the regulation of coal bed methane operations, which are technologically different from conventional oil and gas operations. This inexperience has created uncertainty regarding how these agencies will interpret air, water and waste laws and regulations and other requirements to coal bed methane drilling, fracture stimulation methods, production and water disposal operations. The Company will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between governmental environmental agencies. The Company could face significant liabilities to the government and third parties for discharges of oil, natural gas or other pollutants into the air, soil or water, and the Company could have to spend substantial amounts on investigations, litigation and remediation. Moreover, failure by the Company to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of investigatory and remedial obligations and the issuance of injunctions that restrict or prohibit the performance of operations. See "—Government Regulation of the Oil and Gas Industry—Environmental Matters."

The Company's business depends on transportation facilities owned by others.

The marketability of the Company's gas production depends in part on the availability, proximity and capacity of pipeline systems owned by third parties, and changes in the Company's contracts with these third parties could materially affect the Company's operations. The Company, through its subsidiaries, has entered into a series of firm transportation service agreements with Colorado Interstate Gas Company providing for the transportation of the Company's natural gas production from the Raton Basin to the Mid-Continent markets. See "—Customers and Markets—Gas Marketing and Transportation."

In addition, federal, foreign, state, provincial and local regulation of gas and oil production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, and general economic conditions could adversely affect the Company's ability to transport its natural gas.

Market conditions could cause the Company to incur losses on its transportation contracts.

The Company has gas transportation contracts that require it to transport minimum volumes of natural gas. If the Company ships smaller volumes, it may be liable for the shortfall. Unforeseen events, including production problems or substantial decreases in the price for natural gas, could cause the Company to ship less than the required volumes, resulting in losses on these contracts. See Note 13 to the Consolidated Financial Statements.

The Company depends on key personnel and does not have employment agreements with its executive officers.

The Company's success depends on the continued services of its executive officers and a limited number of other senior management and technical personnel, and the Company does not have employment agreements with these employees. The Company's key personnel include Mark S. Sexton, President and Chief Executive Officer, Dennis R. Carlton, Executive Vice President—Exploration and Chief Operating Officer, Kevin R. Collins, Executive Vice President—Finance, Chief Financial Officer, Treasurer and Secretary and J. Scott Zimmerman, Vice President—Operations and Engineering. Loss of the services of any of these people could result in financial losses and interruptions in operations.

The Company does not pay dividends.

The Company has never declared nor paid any cash dividends on its common stock and management has no intention to do so in the near future.

The Company's articles of incorporation and bylaws have provisions that discourage corporate takeovers and could prevent shareholders from realizing a premium on their investment.

The Company's articles of incorporation and bylaws contain provisions that may have the effect of delaying or preventing transactions involving actual or potential changes in control, including transactions that otherwise could involve payment of a premium over prevailing market prices to shareholders for their common stock. These provisions, among other things, provide for a staggered board of directors and noncumulative voting in the election of the board and impose procedural requirements on shareholders who wish to make nominations for the election of directors or propose other actions at shareholders' meetings. Also, the Company's articles of incorporation authorize the board to issue up to 24,900,000 shares of preferred stock without shareholder approval and to set the rights, preferences and other designations, including voting rights, of those shares as the board may determine.

On July 7, 1997, Evergreen's board of directors adopted a shareholder rights agreement, pursuant to which uncertificated stock purchase rights were distributed to shareholders of the Company at a rate of one right for each share of common stock held of record. The rights plan may impede a takeover of Evergreen not supported by the board, including a takeover that may be desired by a majority of the Company's shareholders or involving a premium over the prevailing stock price.

The Company's stock price has been and is likely to continue to be volatile.

The market price of Evergreen's common stock has been volatile and is likely to continue to fluctuate. During 2002, the price of the common stock on the NYSE ranged from a low of $15.45 per share to a high of $23.50 per share (as adjusted to reflect the Company's two-for-one stock split on September 16, 2003). During 2003, the price ranged from a low of $20.65 to a high of $33.75 (as adjusted to reflect the Company's two-for-one stock split on September 16, 2003). The market price of Evergreen's common stock is subject to many factors, including:

- prices for oil and natural gas;
- general stock market conditions;
- conditions in the Company's industry;
- changes in the Company's revenues and earnings; and
- changes in analyst recommendations and projections.

ITEM 2. PROPERTIES

Evergreen's principal estimated proved reserves and producing properties are located in the Raton Basin in southern Colorado, substantially all of which are operated by the Company. Evergreen also has estimated proved reserves and producing properties in the Piceance Basin in western Colorado, the Uintah Basin in eastern Utah, and the Western Canada Sedimentary Basin. In addition, Evergreen holds undeveloped acreage in the Forest City Basin in eastern Kansas and in the Cook Inlet-Susitna Basin in Alaska. The following table sets forth the Company's estimated proved reserves and the associated pre-tax net present value of estimated proved reserves discounted at 10%.

	As of December 31, 2003					
	Proved Reserve Quantities				Net Present Value(1)	
Location	Natural Gas (MMcf)	Oil (Mbbl)	Total (MMcfe)	Percent of Total	Value (millions)	Percent of Total
Raton Basin	1,392,763	—	1,392,763	93.2%	$2,542	93.7%
Piceance and Uintah Basins	61,199	690	65,339	4.4%	98	3.6%
Western Canada Sedimentary Basin	32,258	735	36,668	2.4%	73	2.7%
Total	1,486,220	1,425	1,494,770	100.0%	$2,713	100.0%

(1) Before future income taxes; assumes weighted average year-end spot price of $5.49 per Mcfe.

Raton Basin Operations

The Raton Basin covers an area that is approximately 80 miles long, north to south, and about 50 miles wide, east to west, encompassing southeastern Colorado and northeastern New Mexico. The Raton Basin contains two coal-bearing formations, the Vermejo formation coals located at depths of between 450 and 4,000 feet and the shallower Raton formation coals, located at the surface to approximately 3,000 feet in depth. Production from the Vermejo coals represents approximately 79% of the total production from the Raton Basin and approximately 78% of the total proved reserves in the Raton Basin. To date, the majority of Evergreen's production has been from the Vermejo formation coals; however, the Company is now successfully developing Raton formation coal seams and interbedded sandstones as well.

Development History

Exploration for coal bed methane in the Raton Basin began in the late 1970s and continued through the late 1980s, with several companies drilling and testing more than 100 wells during this period. The absence of a pipeline to transport gas from the Raton Basin prevented full-scale development until January 1995, when Colorado Interstate Gas Company completed the construction of the Picketwire Lateral.

Since December 1991, the Company has acquired oil and gas leases covering approximately 385,000 gross acres in the Raton Basin. The initial 70,000 acres were acquired in 1991, and additional acreage was purchased from individual owners under various lease terms. The Company has also increased its acreage positions and production through several acquisitions beginning in 1998 through 2001.

Evergreen has a 100% working interest in three federal units, the Spanish Peaks Unit, the Cottontail Pass Unit and the Sangre de Cristo Unit. The total gross acreage in the federal units is approximately 138,000 acres. The Company is the named operator for all of these units. Formation of a unit simplifies lease maintenance so that the Company, as the operator, can base development decisions within the unit on technical, geologic and geophysical data and operational and cultural considerations rather than on the fulfillment of lease term obligations.

Because of the inclusion of federal leases in the unit, administration within a federal unit is governed by federal rules. Production from any well in the unit area will maintain all of the leases beyond their primary terms. In October 1997, the first "participating area" was designated by the Bureau of Land Management under the Unit Agreement. Gas production in the participating area is pooled and shared by the royalty owners, overriding royalty owners and working interest owners in that area in proportion to their acreage ownership of the mineral estate in the area. The participating area is adjusted annually to encompass additional acreage as additional wells are completed.

Evergreen also has working interests of between 75% and 100% in areas adjacent to the federal units, which comprise approximately 247,000 gross acres.

Raton Basin Geology

Evergreen produces coal bed methane from the high quality bituminous coal resource of the Raton Basin. The basin is a large asymmetric sedimentary trough that developed along the western margin of an ancient Rocky Mountain seaway during the Cretaceous and Tertiary period between 65 to 45 million years ago. Today, the geologic history of what was once a lush tropical coastline and alluvial plain cut by meandering rivers, which subsequently underwent deep burial, tectonism, igneous intrusion, and uplift, is recorded in the rocks of the region; the continued exploration of the basin by Company geologists is increasing the understanding of the coal bed methane resource base and identifying new hydrocarbon systems and additional unconventional reservoir types.

The Company's current acreage sits squarely in the middle of the basin and contains some of the thickest documented net coal packages in the region. The coal-bearing strata are located primarily in two major groups, the Vermejo and Raton formations, and represent coal development in two slightly contrasting environments. The Vermejo coals represent peat accumulation on an expansive flat-lying flood-plain which was partially protected from erosion by sandy coastal barriers of the underlying Trinidad Sandstone, while the Raton coals represent peat development on a broad, open, humid alluvial fan. Collectively, both formations reflect the development of substantial peat swamps and thick boggy mires, which covered most of the region during Cretaceous and Tertiary times. Subsequent burial under high pressures and temperatures has caused the original peat accumulation to convert into coal, which has high rank and consequentially high gas storage capacity. During burial, small fractured surfaces (cleats) developed throughout the coal, which, coupled with the tectonic forces acting on the region during the building of the Rocky Mountains, has provided significant permeability within the coals, allowing for the extraction of coal bed methane gas and associated water.

The Company produces methane from wells that are generally completed in the laterally continuous Vermejo coals. Individual Vermejo coal seams can be readily traced over several miles, commonly from well to well. Total net Vermejo coal thickness can locally approach 35 feet in five to 15 individual seams, which may vary in thickness from one to 10 feet.

The shallower Raton formation coals are generally less continuous from well to well, but increasingly represent a very significant resource throughout the basin. Total net Raton coal thickness locally approaches 90 feet in 10 to 25 individual seams, which may vary in thickness from one to 15 feet. Commonly interbedded with the Raton coals are large sandstone channel complexes, which are increasingly identified as additional potential tight-gas and unconventional sand reservoirs.

Coal Bed Methane Versus Traditional Natural Gas

Methane is the primary commercial component of the natural gas stream produced from traditional gas wells. Methane also exists in its natural state in coal seams. Natural gas produced from traditional wells also contains, in varying amounts, other hydrocarbons. However, the natural gas produced from coal beds generally contains only methane and, after simple dehydration, becomes pipeline-quality gas.

Coal bed methane production is similar to traditional natural gas production in terms of the physical producing facilities and the product produced. However, the subsurface mechanisms that allow the gas to move to the wellbore and the producing characteristics of coal bed methane wells differ greatly from traditional natural gas production. Unlike conventional gas wells, which require a porous and permeable reservoir, hydrocarbon migration and a natural structural and/or stratigraphic trap, coal bed methane gas is trapped in the molecular structure of the coal itself until released by pressure changes resulting from the removal of in situ water or natural gas in the micropore system.

Methane is created as part of the coalification process, though coals vary in their methane content per ton. In addition to residing in open spaces in the coal structure, methane is absorbed onto the inner coal surfaces. When the coal is hydraulically fracture stimulated and exposed to lower pressures through the de-watering process, the gas is released from (desorbs from) the coal. Whether a coal bed will produce commercial quantities of methane gas depends on the coal quality, its original content of gas per ton of coal, the thickness of the coal beds, the reservoir pressure, the rate at which gas is released from the coal (diffusivity) and the existence of natural fractures and cleating (permeability) through which the released gas can flow to the wellbore. Frequently, coal beds are partly or completely saturated with water. As the water is produced, internal pressures on the coal are decreased, allowing the gas to desorb from the coal and flow to the wellbore. Unlike traditional gas wells, new coal bed methane wells often produce water for several months and then, as the water production decreases, natural gas production increases as the coal seams de-water.

In order to establish commercial gas production rates, a permanent conduit between the individual coal seams and the wellbore must be created. This is accomplished by hydraulically creating, and propping open with special quality sand, artificial fractures within the coal seams (known as "fracing" in the industry) so the pathway for water and gas migration to the wellbore is enhanced. These fractures are filled (propped) with uniform sized sand and become the enhanced conduits for water and methane to reach the well. The rate at which the gas is released from the coal and the ability of gas to move through the coal to the wellbore are the key determinants of the rate at which a well will produce.

Deep Fractured Shales, Raton Conglomerate and Sandstone Reservoirs

In 2002, the Company embarked on a series of detailed geological studies and drilled exploratory wells aimed at evaluating additional unconventional reservoir systems throughout the Raton Basin. These ongoing studies have focused efforts on gas-charged sandstones and conglomerates interbedded within the currently producing Vermejo and Raton formation coals and deeper gas-bearing shales, which underlie the entire region.

The conglomerate and sandstones currently being identified (and actively produced in several parts of the Company's acreage), reflect stacked large scale meandering river channel complexes and regional sandy braided alluvial fans that at one time crosscut the Cretaceous-Tertiary peat swamps. During burial, excess gas generated during the coalification process locally became trapped within the pore spaces of these sandstones and now form "Tight-Gas Sand" reservoirs. The increasing recognition of the orientation in the subsurface of such ancient drainage system is allowing the strategic sighting of wells in specific sand prone areas, which may ultimately increase the region's total resource base.

The Raton Basin shales, termed the Niobrara and Pierre Shale formations, are approximately 3,000-feet thick and underlie the currently producing intervals. The shales collectively reflect deposits of blanket-like organic rich mudstones, which accumulated in quiet water condition on the sea floor. Deeper exploratory test wells (2,000 to 6,000 feet) aimed at identifying areas of enhanced fracture permeability may ultimately lead to the development of a significant "Shale Gas" resource.

Coal Bed Methane Technology

Thin multi-layer coal bed methane and unconventional tight-gas reservoirs create a multitude of challenges for drilling, reservoir and production engineers, including the challenge of minimizing formation damage and then isolating and completing individual zones in order to maximize recovery of the resource in place. Management believes that the Company has developed highly effective procedures for drilling and completing such reservoirs.

Damage to the Raton Basin coals from conventional drilling mud systems invading the cleat fracture surfaces and reducing their permeability has been mitigated by utilizing specialized air-drilling techniques using percussion air-hammers.

All coals in the Raton Basin require hydraulic fracture stimulation to attain economic production rates. Through its wholly owned subsidiary, Evergreen Well Service Company, the Company has developed technology that the Company believes is at the leading edge of coal bed methane well completions. The new technology uses proprietary high quality nitrogen foamed fluids as the fracturing media and the industry's first "built-for-purpose" 2⅞-inch diameter coiled tubing fracturing units to selectively place proppant in individual seams. The Company believes that this fracturing technology demonstrates its commitment to the continued role that technology innovation will play in developing some of the region's resources.

Water Production and Disposal

Based on the Company's experience in coal bed methane production in the Raton Basin and extensive laboratory analysis of water samples taken from its coal bed methane wells, management believes that the groundwater produced from the Raton Basin coal seams will not exceed permit levels and will be suitable for discharge into arroyos, surface water, well-site pits or evaporation ponds pursuant to permits obtained from the State of Colorado. Recent gas analyses confirm that the gas stream is 99% pure methane and lacks other hydrocarbon sources of contamination. In some cases the water is of such quality that it can be discharged to arroyos and surface water under general water discharge permits issued to the Company by the State of Colorado. These permits give Evergreen the flexibility to add water discharge points on an as-needed basis with minimal administrative paperwork and within 30 days or less of application. Evergreen has in excess of 300 approved discharge points and has received an increase in the total volume of water permitted for surface discharge. Approval of these requests is uncertain and is dependent upon completion of additional study by the State of Colorado. Additionally, the Company contracts with an independent water sampling company that collects the water samples and monitors all the Company's water management program. These monitoring costs are directly related to the number of well-site pits, evaporation ponds and discharge points. Because it originates in a natural groundwater system, there is some uncertainty whether water currently being discharged to streams and arroyos will continue to meet permit standards for total iron and suspended solids. Water not meeting these discharge standards can be disposed of in well-site pits and evaporation ponds. When water of lesser quality is discovered or Evergreen's wells produce water in excess of the applicable permit limits, the Company may have to drill additional disposal wells to re-inject the produced water into deeper sandstone horizons. Such drilling and disposal would require the Company to obtain permits, similar to those obtained in the past.

Raton Basin Production

Evergreen's natural gas sales from the Raton Basin did not commence until the completion of a pipeline system in January 1995, which connected its Raton Basin wells to the Colorado Interstate Gas Company pipelines. From January 1995 through December 2003, the Company sold an aggregate of approximately 167 Bcf of coal bed methane gas from the Raton Basin. Because of the importance of removing water from the coal seams to enhance gas production, the Company expects to continue production from more modest wells because of the beneficial ambient effect of pressure reduction in adjacent, more productive wells. Each well creates its own "cone of depression" around the wellbore. Evergreen believes that some of its Raton Basin wells on adjacent 160-acre sites have already created overlapping cones of depression, enhancing gas production in each well within this pattern. In some cases this pattern of interference can be enhanced by drilling a fifth and sixth well in the 640-acre section.

Raton Basin gas contains insignificant amounts of contaminants, such as hydrogen sulfide, carbon dioxide or nitrogen, that are sometimes present in conventional natural gas production. Therefore, the properties of Raton Basin gas, such as heat content per unit volume (British Thermal units, or "Btu"), are close to the average properties of pipeline gas from conventional gas wells.

Piceance and Uintah Basin Operations

Evergreen established its position in the Piceance and Uintah Basins through an acquisition in October 2003. Evergreen holds approximately 171,000 net acres in the aggregate in the two basins. At December 31, 2003, Evergreen had estimated net proved reserves of 65 Bcfe in these basins, 51% of which were classified as proved developed. Evergreen's current production in these basins is from reserves in tight sand and shale formations. Evergreen's net daily sales for December 2003 were averaging approximately 5 MMcfe from a total of 106 net producing wells. Evergreen operates 98% of its production in these basins and holds an average working interest of 84% across its producing properties.

Western Canada Sedimentary Basin Operations

Evergreen's position in the Western Canada Sedimentary Basin was established in connection with the October 2003 acquisition. Evergreen holds approximately 101,000 net acres in this basin. At December 31, 2003, Evergreen had estimated net proved reserves of 37 Bcfe in Canada, 72% of which were classified as proved developed. Evergreen's current production in this basin is from reserves in tight sand and shale formations. Evergreen's net daily sales for December 2003 were averaging approximately 9 MMcfe from a total of 78 net producing wells. Evergreen operates 80% of its production in this basin and holds an average working interest of 63% across its producing properties.

Oil and Natural Gas Reserves

The table below sets forth Evergreen's quantities of estimated proved reserves, as audited or prepared as of December 31, 2003, 2002 and 2001 by independent petroleum engineering consultants Netherland, Sewell & Associates, Inc. All estimated proved reserves are located in North America, and the present value of estimated future net revenues from these reserves was calculated on a non-escalated price basis discounted at 10% per year as of the periods indicated. There has been no major discovery or other favorable or adverse event that is believed to have caused a significant change in estimated proved reserves subsequent to December 31, 2003.

	December 31,		
	2003	2002	2001
Proved Developed Oil and Gas Reserves (MMcfe)	921,779	795,874	684,167
Proved Undeveloped Oil and Gas Reserves (MMcfe)	572,991	442,928	366,476
Total Proved Oil and Gas Reserves (MMcfe)	1,494,770	1,238,802	1,050,643
Future Net Revenues (before future income tax expenses) (in thousands) (1)	$6,095,611	$3,648,926	$1,336,302
Present Value of Future Net Revenues (before future income tax expenses) (in thousands) (1)	$2,712,603	$1,634,741	$ 598,462

(1) The weighted average year-end spot prices for the purpose of estimating Evergreen's future net revenues were $5.49, $4.22 and $2.32 per Mcfe at December 31, 2003, 2002 and 2001, respectively.

Reference should be made to Note 16 to the Consolidated Financial Statements for additional information pertaining to the Company's proved oil and gas reserves. During the year ended December 31, 2003, the Company did not file any reports that included estimates of total proved net oil or gas reserves with any federal agency other than the SEC and the Department of Energy.

Production

The following table sets forth the Company's net oil and natural gas sales for the periods indicated. The Company had no oil or liquids production during 2002 and 2001.

	2003		2002	2001
	Natural Gas (MMcf)	Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas (MMcf)
Raton Basin	45,443	—	38,988	30,807
Piceance and Uintah Basins(1)	260	6	—	—
Western Canada Sedimentary Basin(1)	470	10	—	—
Total	46,173	16	38,988	30,807
Average sales price(2) (per Mcf for gas and Bbl for oil)	$ 4.66	$25.94	$ 2.86	$ 3.89

(1) Includes production volumes from the date of acquisition of Carbon for the period from October 29, 2003 through December 31, 2003.

(2) Includes the effects of hedging.

Production Costs

The following table sets forth lease operating expenses, transportation costs and production and property taxes per Mcfe, for the periods indicated.

	Year Ended December 31,		
	2003	2002	2001
Lease operating expenses	$0.45	$0.41	$0.40
Transportation costs	$0.31	$0.31	$0.31
Production and property taxes	$0.24	$0.15	$0.18

Productive Wells

The following table sets forth the number of gross and net producing wells the Company had as of December 31, 2003.

	Gas Wells		Oil Wells	
Location	Gross	Net	Gross	Net
United States:				
Raton Basin	1,014	973	—	—
Piceance and Uintah Basins and other	127	106	1	1
Total—United States	1,141	1,079	1	1
Western Canada Sedimentary Basin	126	73	13	5
United States and Canada	1,267	1,152	14	6

The following table reflects the number of gross and net producing wells the Company had in the Raton Basin for each of the prior five fiscal years ended December 31.

	Raton Basin Producing Gas Wells	
	Gross	Net
2003	1,014	973
2002	878	837
2001	713	681
2000	520	491
1999	258	252

Acreage

At December 31, 2003, Evergreen held developed and undeveloped acreage as set forth below:

Location	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Raton Basin	186,728	169,050	198,695	173,139	385,423	342,189
Piceance and Uintah Basins	47,914	42,341	145,621	128,984	193,535	171,325
Western Canada Sedimentary Basin	86,080	40,568	71,313	60,106	157,393	100,674
Kansas	—	—	714,739	667,492	714,739	667,492
Alaska	—	—	294,890	293,851	294,890	293,851
Other	1,740	798	28,771	20,778	30,511	21,576
Total	322,462	252,757	1,454,029	1,344,350	1,776,491	1,597,107

The following table sets forth the expiration dates of the gross and net acres subject to North American leases summarized in the table of undeveloped acreage.

Twelve Months Ended:	Acres Expiring	
	Gross	Net
December 31, 2004	136,136	123,674
December 31, 2005	135,120	124,424
December 31, 2006	354,003	343,124
December 31, 2007	85,294	74,947
December 31, 2008	69,603	66,345

Drilling Activities

The Company's drilling activities for the periods indicated are set forth below:

	Year Ended December 31,					
	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Domestic						
Exploratory Wells						
Productive	29	29	16	12	1	1
Water Disposal	3	3				
Dry	—	—	—	—	—	—
Total	32	32	16	12	1	1
Development Wells						
Productive	149	141	150	142	145	137
Water Disposal	—	—	3	3	—	—
Dry	—	—	—	—	—	—
Total	149	141	153	145	145	137
International						
Exploratory Wells						
Productive	2	1	2	2	5	5
Dry	—	—	2	2	1	1
Total	2	1	4	4	6	6

Office and Operations Facilities

The Company leases its corporate offices in Denver, Colorado. The lease covers approximately forty thousand square feet and expires in 2008. The Company also leases other office facilities in Calgary, Alberta, Canada; Ottawa, Kansas; Wasilla, Alaska; and Price, Utah. The Company believes its office space will be sufficient for the foreseeable future.

ITEM 3. LEGAL PROCEEDINGS

Except as provided below, Evergreen is not engaged in any material legal proceedings to which the Company or its subsidiaries are a party or to which any of its property is subject.

Evergreen was named as a defendant in a class action lawsuit filed in the Denver District Court on December 26, 2002. The plaintiffs, Mountain West Exploration, Inc., Joel Nelson and Synergy Operations Company, LLC, are royalty owners and overriding royalty owners with respect to Evergreen's Raton Basin properties who alleged in the lawsuit that amounts paid for production attributable to the royalty owners violated the terms of the applicable leases and laws in various respects, including the value of production sold, permissibility of deductions and accuracy of quantities upon which royalties are calculated. The plaintiffs sought to recover damages and injunctive relief.

As a result of a preliminary settlement between the parties, Evergreen recorded a $3.3 million pre-tax charge to earnings in 2003. This total includes the settlement, legal fees and other associated costs. The court recently approved the preliminary settlement agreement. Final approval of the settlement is expected in April 2004.

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

During the quarter ended December 31, 2003, a proposal to amend the Company's Amended and Restated Articles of Incorporation to increase the number of authorized shares of common stock from 50,000,000 to 100,000,000 shares was submitted to the security holders. At the Special Meeting of Shareholders held on November 20, 2003, 33,027,521 votes were cast for the proposal, 1,910,105 votes were cast against the proposal and 23,912 votes abstained.

PART II

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

Principal Market and Price Range of Common Stock

The Company's common stock is listed on the New York Stock Exchange (its principal market). The following table sets forth the range of high and low sales prices per share of common stock for the periods indicated. The sales prices per share give effect to the two-for-one split of Evergreen's common stock effective September 16, 2003 for all periods presented.

	High	Low
Year Ended December 31, 2002		
First Quarter	$21.83	$16.51
Second Quarter	22.70	19.63
Third Quarter	21.26	15.45
Fourth Quarter	23.50	18.88
Year Ended December 31, 2003		
First Quarter	23.25	20.65
Second Quarter	28.50	22.30
Third Quarter	28.35	24.49
Fourth Quarter	33.75	26.60

As of February 26, 2004, there were approximately 1,400 holders of record of the common stock.

On November 25, 2003, the Company filed Articles of Amendment to its Amended and Restated Articles of Incorporation with the Department of State of the State of Colorado to increase the number of authorized shares of the Company's common stock from 50,000,000 shares to 100,000,000 shares. The amendment was duly approved by both the Company's board of directors and the Company's shareholders.

Dividend Policy

The Company has not declared nor paid and does not anticipate declaring or paying any dividends on its common stock in the near future. Any future determination as to the declaration and payment of dividends will be at the discretion of the Company's board of directors and will depend on then-existing conditions, including the Company's financial condition, results of operations, contractual restrictions, capital requirements, business prospects and such other factors as the board deems relevant. The Company's $200.0 million revolving credit facility has various restrictions on the declaration and payment of dividends, including a limitation equal to 50% of the Company's net income for the prior fiscal year.

ITEM 6. SELECTED FINANCIAL DATA

The selected consolidated financial information presented below for the years ended December 31, 1999 through 2003 is derived from the Consolidated Financial Statements of the Company.

This information should be read in conjunction with the Consolidated Financial Statements and Notes thereto and Management's Discussion and Analysis of Financial Condition and Results of Operations. Effective October 29, 2003, the Company completed its acquisition of Carbon (see Note 3 to the Consolidated Financial Statements). Carbon's results of operations from October 29, 2003 through December 31, 2003 are included in Evergreen's consolidated statement of operations. In 2002, the Company impaired approximately $51.5 million of international oil and gas properties, net of a foreign currency exchange gain of approximately $1.0 million (see Note 4 to the Consolidated Financial Statements). The Company acquired certain properties in September 2000 and included the operations of these properties in its consolidated operations beginning September 1, 2000. On February 18, 1999, Evergreen sold its 49% interest in Maverick Stimulation Company and recorded a gain net of tax of approximately $0.5 million or $0.02 per diluted share. This transaction was accounted for as a discontinued operation and the results of operations have been excluded from continuing operations in the consolidated statements of operations for all periods presented. Certain reclassifications have been made to prior financial statements to conform with the current presentation. The table gives effect to the two-for-one split of Evergreen's common stock effective September 16, 2003 for all periods presented. See also Note 5 to the Consolidated Financial Statements for a discussion of the cumulative effect of change in accounting principle related to asset retirement obligations recognized in 2003.

	As of or for the Years Ended December 31,				
	2003	2002	2001	2000	1999
	(in thousands, except per share amounts)				
Statement of Operations Data					
Revenues:					
Oil and natural gas revenues	$ 215,460	$ 111,550	$ 119,745	$ 59,128	$ 26,722
Interest and other	980	576	1,025	565	207
Total revenues	216,440	112,126	120,770	59,693	26,929
Expenses:					
Lease operating expenses	20,970	16,161	12,228	7,475	4,245
Transportation costs	14,486	12,233	9,524	5,902	4,001
Production and property taxes	11,096	5,960	5,472	2,567	1,146
Depreciation, depletion and amortization	26,913	20,916	16,212	8,190	4,757
Impairment of international properties	1,712	51,546	—	—	—
General and administrative expenses	14,619	9,226	6,985	4,364	3,024
Interest expense	8,251	8,345	8,331	3,330	1,927
Other, net	2,874	645	653	178	175
Total expenses	100,921	125,032	59,405	32,006	19,275
Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principle	115,519	(12,906)	61,365	27,687	7,654
Income tax provision (benefit)	42,178	(4,582)	22,838	10,695	2,979
Income (loss) from continuing operations before cumulative effect of change in accounting principle	73,341	(8,324)	38,527	16,992	4,675
Discontinued operations					
Gain on disposal of discontinued operations, net	—	—	—	—	452
Net income (loss) before cumulative effect of change in accounting principle	73,341	(8,324)	38,527	16,992	5,127
Cumulative effect of change in accounting principle, net	713	—	—	—	—
Net income (loss)	72,628	(8,324)	38,527	16,992	5,127
Preferred stock dividends	—	—	—	(2,929)	—
Net income (loss) attributable to common stockholders	$ 72,628	$ (8,324)	$ 38,527	$ 14,063	$ 5,127
Basic income (loss) per common share					
From continuing operations, before cumulative effect of change in accounting principle	$ 1.86	$ (0.22)	$ 1.04	$ 0.46	$ 0.18
From discontinued operations	—	—	—	—	0.02
Cumulative effect of change in accounting principle, net of tax	(0.02)	—	—	—	—
Basic income (loss) per common share	$ 1.84	$ (0.22)	$ 1.04	$ 0.46	$ 0.20
Diluted income (loss) per common share					
From continuing operations, before cumulative effect of change in accounting principle	$ 1.79	$ (0.22)	$ 0.99	$ 0.43	$ 0.17
From discontinued operations	—	—	—	—	0.02
Cumulative effect of change in accounting principle, net of tax	(0.02)	—	—	—	—
Diluted income (loss) per common share	$ 1.77	$ (0.22)	$ 0.99	$ 0.43	$ 0.19
Statement of Cash Flows Data					
Net cash provided by (used in):					
Operating activities	$ 149,951	$ 55,394	$ 91,605	$ 33,033	$ 11,208
Investing activities	(150,571)	(114,766)	(122,547)	(144,196)	(43,864)
Financing activities	3,569	57,198	29,965	114,510	31,994
Balance Sheet Data					
Cash and cash equivalents	$ 3,820	$ 871	$ 3,024	$ 4,034	$ 651
Net property and equipment	862,638	580,416	532,589	411,949	174,334
Total assets	905,086	606,761	556,025	450,745	184,369
Total long-term indebtedness	249,373	236,000	181,000	149,748	15,500
Total stockholders' equity	482,928	312,428	314,940	266,852	153,510

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

The following information should be read in conjunction with the Consolidated Financial Statements and Notes presented elsewhere in this Form 10-K. The Company follows the full-cost method of accounting for oil and gas properties. See "Summary of Accounting Policies," included in Note 1 to the Consolidated Financial Statements.

Overview

Evergreen is an independent energy company primarily engaged in the operation, development, production, exploration, and acquisition of North American unconventional natural gas properties. Evergreen is one of the leading developers of coal bed methane reserves in the United States. Evergreen's operations are principally focused on developing and expanding its coal bed methane project located in the Raton Basin in southern Colorado. Evergreen recently acquired producing properties in the Piceance Basin in western Colorado, the Uintah Basin in eastern Utah and the Western Canada Sedimentary Basin (see Note 3 to the Consolidated Financial Statements). Evergreen has natural gas production from tight sands and shales in these newly acquired areas that it intends to enhance. Evergreen is also evaluating the additional coal bed methane and other gas resource potential within each of these basins. In addition, Evergreen has initiated coal bed methane projects in the Forest City Basin in eastern Kansas and the Cook Inlet-Susitna Basin in Alaska.

In 2003, Evergreen achieved several milestones and performance benchmarks in financial and operational areas. The following are highlights established in 2003:

- Production volumes increased to 46.3 Bcfe in 2003 from 39.0 Bcfe in 2002, or an increase of 19%.
- Oil and natural gas revenues increased to $215.5 million in 2003 from $111.6 million in 2002, or an increase of 93%, due primarily to increased production in the Raton Basin and an increase in natural gas prices.
- Net income increased to $72.6 million in 2003 from a loss of $8.3 million in 2002.
- In October 2003, Evergreen completed an $88.4 million acquisition that added 97 Bcfe in total estimated proved reserves and established new areas of development in the Piceance Basin in western Colorado, the Uintah Basin in eastern Utah and the Western Canada Sedimentary Basin.
- Gross producing wells exceeded 1,000 in the Raton Basin.
- Evergreen increased estimated proved reserves to 1.495 Tcfe in 2003 from 1.239 Tcfe in 2002, or an increase of 21%.
- Evergreen replaced 653% of its 2003 production at a finding and development cost of $0.88 per Mcfe.
- The abandonment of the properties in the United Kingdom, Northern Ireland and Republic of Ireland, Falkland Islands and Chile was completed. Evergreen's focus is primarily on North American unconventional natural gas plays, which include coal bed methane, tight sands and fractured shales development.
- Evergreen has accumulated over 700,000 gross acres in the Forest City Basin in Kansas and drilled over 20 wells in 2003. The Company had scheduled an aggressive drilling program in Kansas in 2004, but has decided that it is prudent to proceed with a more moderate development pace in Kansas this year in order to better assess the technical aspects of the development.

2004 Operational and Financial Objectives

Evergreen expects that 2004 will be a year for accelerated development and expansion into newly acquired areas. Evergreen's capital budget for 2004 is $220 million. Of this total, approximately half is expected to be directed to Evergreen's coal bed methane operations in the Raton Basin. Evergreen intends to increase its drilling program from 183 wells in 2003 to approximately 380 wells in 2004. Evergreen plans to continue to focus on its core area in the Raton Basin by increasing the drilling program from 160 wells in 2003 to up to 200 wells in 2004. Evergreen's plans for the recently acquired areas in the Piceance and Uintah Basins include a drilling program of 55 gross wells in the aggregate. Plans for the Western Canada Sedimentary Basin include a drilling program of 65 gross wells. Evergreen's acquisition of these properties was consistent with its focus on North American unconventional natural gas properties, providing diversification in terms of both current production volumes and long-term growth opportunities.

Evergreen's ability to increase its drilling program in 2004 is dependent on the following:

- Evergreen's ability to hire and train additional personnel for drilling and completion services. Evergreen business strategy has been to maintain control of operations through vertical integration. As expansion in other geographic areas occurs, vertical integration is dependent on hiring qualified new personnel. Evergreen is currently hiring new personnel and anticipates that it can fill its needs for all areas.
- Availability of third party contractors for drilling rigs, completion services and gathering system construction. Evergreen is in the process of acquiring additional drilling rigs, completion rigs and pipeline construction crews for the Raton, Piceance and Uintah Basins to reduce the Company's reliance on third party contractors.
- Obtaining federal drilling permits from the Bureau of Land Management in the Piceance and Uintah Basins. Evergreen anticipates that it will be able to obtain the necessary permits to complete the 2004 drilling plans.
- Acquisition of proprietary 2D and 3D seismic data. A 3D seismic crew has been contracted for the Uintah Basin and a 2D seismic crew has been contracted for the Western Canada Sedimentary Basin. Evergreen anticipates that the necessary permits will be obtained and the acquisition, processing and interpretation of the proprietary seismic data will confirm several 2004 drilling locations.

Evergreen expects that it will increase production in 2004 as compared to 2003 due to continued development of the Raton Basin and a full year of production and additional drilling in the Piceance, Uintah and Western Canada Sedimentary Basins. Evergreen's revenues and results of operations depend upon many factors, but are largely dependent on the market price of oil and natural gas. The volatility of natural gas prices in North America could continue as a result of supply and demand fundamentals. Due to the volatility of natural gas prices, Evergreen intends to hedge future natural gas production in accordance with its hedging policy. Evergreen has hedged approximately 42 Bcfe of its estimated 2004 natural gas production at a net realized price of $4.67 per Mcf.

Evergreen anticipates that lease operating expenses on a per-Mcfe basis will be higher in 2004 than in 2003 as a result of higher operating costs in the newly acquired Piceance, Uintah and Western Canada Sedimentary Basin properties. The higher per-Mcfe costs in the new areas are due to higher non-operated costs. In addition, as these areas are beginning to be more fully developed, there are few economies of scale that have been established.

Depreciation, depletion and amortization expense on a per-Mcfe basis is expected to increase in 2004 over prior years, primarily due to the acquisition of the oil and natural gas properties in the Piceance, Uintah and Western Canada Sedimentary Basins. The Company's finding and development costs for the last five years have averaged $0.65 per Mcfe, which is substantially lower than the industry average.

Results of Operations

The following table sets forth certain operating data for the periods presented. On October 29, 2003, Evergreen completed its acquisition of Carbon. Evergreen's consolidated results of operations for the year ended December 31, 2003 include Carbon's results of operations from the date of acquisition through December 31, 2003.

	Years Ended December 31,				
	2003	2002	2001	2000	1999
Oil and natural gas sales (MMcfe)	46,268	38,988	30,807	19,521	13,656
Average daily sales (MMcfe)	126.8	106.8	84.4	53.3	37.4
Average realized sales price per Mcfe (1)	$ 4.66	$ 2.86	$ 3.89	$ 3.03	$ 1.96
Cost Per Mcfe:					
Lease operating expenses	$ 0.45	$ 0.41	$ 0.40	$ 0.38	$ 0.31
Transportation costs	0.31	0.31	0.31	0.30	0.29
Production and property taxes	0.24	0.15	0.18	0.13	0.08
Depreciation, depletion and amortization	0.58	0.54	0.53	0.42	0.35
General and administrative expenses	0.32	0.24	0.23	0.22	0.22
Interest expense	0.18	0.21	0.27	0.17	0.14

(1) Includes effects of hedging

Year ended December 31, 2003 compared to year ended December 31, 2002

Evergreen recorded net income of $72.6 million or $1.77 per diluted share for the year ended December 31, 2003, compared to a net loss of $8.3 million or $0.22 per diluted share for the year ended December 31, 2002.

Oil and natural gas revenues increased to $215.5 million in 2003 from $111.6 million in 2002. This increase was primarily due to a 63% increase in the average realized oil and natural gas price from $2.86 per Mcfe in 2002 to $4.66 per Mcfe in 2003. In addition, oil and natural gas production volumes increased 19% in 2003. Approximately 72% of Evergreen's net production during the year ended December 31, 2003 was hedged using financial instruments (commodity swaps and collars), which resulted in a loss of $11.8 million in 2003 compared to a loss of $6.5 million in 2002. These losses are included in oil and natural gas sales for each period. See "Liquidity and Capital Resources—Hedging Transactions" for more information regarding the Company's hedging activities, including information on hedges currently in place during the year ending December 31, 2004.

Net oil and natural gas production in 2003 increased to 46.3 Bcfe or an average of 126.8 MMcfe per day from 39.0 Bcfe or an average of 106.8 MMcfe per day in 2002. The Piceance, Uintah and Western Canada Sedimentary Basin properties accounted for approximately 0.8 Bcfe of the 2003 production and $3.8 million of gross revenues in 2003. The number of net producing wells increased to 1,158 at December 31, 2003 from 837 at December 31, 2002. Of the Company's total 1,158 net producing wells at December 31, 2003, 185 net wells were acquired in connection with the Carbon acquisition.

Lease operating expenses for 2003 were $21.0 million compared to $16.2 million for 2002. Lease operating expenses from the Piceance, Uintah and Western Canada Sedimentary Basin properties accounted for $0.8 million of the increase. On a per-Mcfe basis, lease operating expenses increased 10% to $0.45 per Mcfe in 2003 from $0.41 per Mcfe in 2002. The increase was primarily due to an increase in well repairs and supplies in the Raton Basin as a result of an increasing number of older wells and surface systems, as well as a higher lease operating expense per Mcfe from the Piceance, Uintah and Western Canada Sedimentary Basin properties.

For the year ended December 31, 2003, production and property taxes were $11.1 million as compared to $6.0 million in 2002. Evergreen pays production taxes on the value of its oil and natural gas physically sold. Accordingly, any financial hedging gains and losses realized by Evergreen, which are recorded as a component of oil and natural gas revenues, are not subject to production taxes. Excluding hedging losses of $11.8 million and $6.5 million for the years ended December 31, 2003 and 2002, respectively, production and property taxes as a percentage of oil and natural gas sales were approximately 4.9% and 5.0%, respectively.

Depreciation, depletion and amortization expense in 2003 was $26.9 million compared to $20.9 million in 2002. On an equivalent Mcfe basis, depreciation, depletion and amortization expense increased to $0.58 per Mcfe in 2003 as compared to $0.54 per Mcfe in 2002. The increase is primarily attributable to the Piceance, Uintah and Western Canada Sedimentary Basin properties, which accounted for approximately $1.8 million of additional depreciation, depletion and amortization expense in 2003.

In 2002, Evergreen recorded an impairment of approximately $51.5 million ($33.2 million net of tax) of certain international oil and gas properties, net of a related foreign currency exchange gain of approximately $1.0 million. Of this amount, approximately $33.1 million was related to the coal bed methane project in the United Kingdom, $13.7 million, net of a foreign currency exchange gain of approximately of $1.0 million, was related to wells drilled in Northern Ireland and the Republic of Ireland and $4.7 million was related to undeveloped acreage held in the Falkland Islands and Chile. The impairment charges of $1.7 million (net of a related foreign currency gain of approximately $1.0 million) incurred in 2003 relate to plugging and abandonment operations done for the United Kingdom and Ireland properties, which were completed as of December 31, 2003.

General and administrative expenses were $14.6 million in 2003, as compared to $9.2 million in 2002. The increase was primarily attributable to a $3.0 million increase in general and administrative compensation, a $0.7 million increase in professional services and a $0.5 million increase in general office expenses, which includes rent, insurance and supplies. General and administrative expenses on a per-Mcfe basis were $0.32 per Mcfe for the year ended December 31, 2003 compared to $0.24 per Mcfe for the year ended December 31, 2002.

Other expense, net of $2.9 million in 2003 included a charge for the settlement of a class action lawsuit and related legal costs of $3.3 million, minority interest in income of $1.3 million and losses on derivative contracts not accounted for as cash flow hedges of $1.2 million, which were partially offset by realized gains on the sale of common stock held in other companies of $3.9 million. See Note 15 to the Consolidated Financial Statements for a table of the components of other expense, net incurred during 2003.

Effective January 1, 2003, Evergreen adopted Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires the fair value of a liability for an asset retirement obligation to be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The adoption of SFAS No. 143 required Evergreen to record a non-cash expense, net of tax, of approximately $0.7 million as a cumulative effect of change in accounting principle in the first quarter of 2003. In addition, Evergreen recorded a non-current liability of approximately $4.6 million and an addition to oil and gas properties and the gas collection system of approximately $3.9 million. See Note 5 to the Consolidated Financial Statements.

Evergreen provided for deferred and current income taxes in 2003 at a rate of 36.5% versus a 35.5% rate in 2002. The increase in the effective tax rate was primarily due to an anticipated increase in Evergreen's federal tax rate. In conjunction with the acquisition of Carbon, Evergreen will be required to pay current income taxes in Canada, which are estimated to be approximately $0.2 million for the two month period ended December 31, 2003.

On a quarterly basis Evergreen is required to review the carrying value of its oil and gas properties under the full-cost accounting rules of the SEC. Under these rules, capitalized costs of proved oil and gas properties, as adjusted for asset retirement obligations, may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10%. Application of the ceiling test generally requires pricing future revenue at the unescalated prices in effect as of the last day of the quarter, with effect given to Evergreen's cash flow hedge positions, and requires a write-down for accounting purposes if the ceiling is exceeded. At December 31, 2003, the spot price that Evergreen would have realized for its oil and natural gas sales was $5.49 per Mcfe. At this price level, Evergreen did not have a write-down because the present value of Evergreen's future net revenues, discounted at 10%, exceeded Evergreen's capitalized costs. If oil and natural gas prices were to drop to lower levels during future periods, Evergreen could be required to record a write-down of its capitalized costs.

Year ended December 31, 2002 compared to year ended December 31, 2001

The Company recorded a net loss of $8.3 million or $0.22 per diluted share for the year ended December 31, 2002, compared to net income of $38.5 million or $0.99 per diluted share for the year ended December 31, 2001. The decrease in net income was due primarily to a non-cash after-tax impairment charge, net of a foreign currency gain, of $33.2 million related to the Company's international properties as discussed below.

Natural gas revenues decreased to $111.6 million in the year ended December 31, 2002 from $119.7 million in the year ended December 31, 2001. This decrease was due to a 26% decline in the average realized oil and natural gas prices of $3.89 per Mcfe in 2001 to $2.86 per Mcfe in 2002. The decrease in the average realized oil and natural gas price was partially offset by a 27% increase in natural gas production. The Company recognized $6.5 million of hedging losses for the year ended December 31, 2002 compared to gains of $13.9 million in 2001. These transactions are included in oil and natural gas sales.

Net gas production for the year ended December 31, 2002 increased to 39.0 Bcfe, or an average of 106.8 MMcfe per day, from 30.8 Bcfe, or an average of 84.4 MMcfe per day, in 2001. The number of net producing wells increased to 837 at December 31, 2002 from 681 at December 31, 2001.

Lease operating expenses in 2002 were $16.2 million compared to $12.2 million in 2001. While overall lease operating expenses increased by $4.0 million in 2002, lease operating expenses on a per-Mcfe basis remained generally consistent at $0.41 per Mcfe in 2002 compared to $0.40 per Mcfe in 2001. The increase was due primarily to an increase in well repairs and compressor maintenance, which was partially offset by a decrease in water disposal costs.

For the year ended December 31, 2002, the Company recorded an impairment of approximately $51.5 million ($33.2 million net of tax), net of a foreign currency exchange gain of approximately $1.0 million, related to property interests in the United Kingdom, Northern Ireland, the Republic of Ireland, the Falkland Islands and Chile as discussed below.

United Kingdom: The Company completed production testing on substantially all of its wells in the United Kingdom by the end of the third quarter of 2002. Because the results of the production testing indicated that the wells, except for the two coal mine methane wells, were not capable of commercial production, the Company recorded a partial impairment of $15.9 million to the asset value of the U.K. properties in the third quarter of 2002. However, at September 30, 2002, the Company believed that there was sufficient value and interest by other entities in the Company's two coal mine methane gas wells and the potential for the application of a "horizontal breach lateral well" concept on its acreage that a value of $15 million to $16 million could be realized through a corporate or asset transaction. However, by year-end 2002, a transaction could not be completed to allow Evergreen to exit the United Kingdom without extensive ongoing involvement from Evergreen's technical personnel. Therefore, due to an unfavorable regulatory environment, high capital costs, the lack of infrastructure for oil and gas development and delays in approval processes, the Company determined to redirect its efforts to North America, and as such the Company decided not to invest any additional funds for the development of a horizontal lateral well concept or the drilling of additional coal mine methane wells. As a result, the Company recorded an impairment charge of approximately $17.2 million in the fourth quarter of 2002, representing the remaining carrying value of the U.K. properties as of December 31, 2002.

Northern Ireland and the Republic of Ireland: During the third quarter of 2002, Evergreen completed its evaluation of the five wells drilled in Northern Ireland and the Republic of Ireland. In the first and second quarters of 2002, the wells were hydraulic fracture stimulated. The Company completed its production testing and determined that estimated gas production from the Mullaghmore and Dowra sandstone were not at a level that would provide an adequate return to the Company. Therefore, the Company recorded an impairment charge against the carrying value of $13.7 million, net of a foreign currency exchange gain of approximately $1.0 million.

Other international: Evergreen recorded an impairment charge against the carrying value of its Falkland Islands and Chile prospects as the Company was unable to determine when these projects would be drilled or monetized. As a result, an impairment charge of $4.7 million was taken in the third quarter of 2002 to eliminate the carrying value of these assets.

General and administrative expenses were $9.2 million in 2002 as compared to $7.0 million in 2001. The increase was primarily due to a $1.2 million increase in general and administrative salaries, bonuses and related benefits. General and administrative expense on a per-Mcfe basis was $0.24 per Mcfe for the year ended December 31, 2002 compared to $0.23 per Mcfe for the year ended December 31, 2001.

Interest expense, net of capitalized amounts, was $8.3 million during each of the years ended December 31, 2002 and 2001. Although average debt balances were higher during 2002, interest expense remained consistent due to a reduction in average interest rates from approximately 6.1% in 2001 to 4.4% in 2002. The increase in average borrowings was due to the funds used for the Company's exploration and development activities in 2002.

The Company provided for deferred income taxes at a rate equal to 35.5% of net loss before taxes for the year ended December 31, 2002. For the first six months of 2001, the Company provided for deferred income taxes at an effective rate of 38% and reduced the percentage to 35.5% in the third quarter of 2001 primarily due to Colorado income tax credits that the Company expected to be able to utilize on a prospective basis. The tax credits relate to the Company's development activities in the Raton Basin.

Liquidity and Capital Resources

Sources and Uses

The Company's primary sources of liquidity are cash provided by operations and debt financing. Capital markets have also been utilized in order to maintain the Company's indebtedness at moderate levels in order to provide sufficient financial flexibility to react to future opportunities. The Company's primary needs for cash are for the operation, development, production, exploration and acquisition of oil and gas properties and working capital obligations.

The Company currently has a $200 million revolving credit facility with a bank group. The credit facility is available through July 1, 2005. Advances pursuant to this credit facility are limited to a borrowing base, which is presently $200 million. The Company may elect to use either LIBOR plus a margin of 1.125% to 1.50% or the prime rate plus a margin of 0% to 0.25%, with margins on both rates determined on the average outstanding borrowings under the credit facility. The borrowing base is redetermined semi-annually by the bank group based upon reserve evaluations of Evergreen's oil and gas properties. An annual commitment fee of 0.375% is charged quarterly for any unused portion of the credit line. The agreement is collateralized by substantially all domestic oil and gas properties and guaranteed by substantially all of the Company's subsidiaries. The credit agreement also contains certain net worth, leverage and ratio requirements. At December 31, 2003, Evergreen had $135.5 million of outstanding borrowings under this credit facility, with a current average interest rate of approximately 2.6%. The Company was in compliance with all loan covenants for all periods presented.

In connection with the purchase of Carbon, the Company assumed a credit facility with Canadian Imperial Bank of Commerce ("CIBC"). At December 31, 2003 outstanding borrowings were $13.9 million. This facility is secured by the Canadian oil and gas properties of the Company. The revolving phase of the Canadian facility expires on March 31, 2004. The facility with CIBC bears interest at a rate equal to banker's acceptance rates plus 1.25% or at the CIBC Prime rate plus 0.5%. The Company's current average interest rate on this credit facility was 5.0% at December 31, 2003. The Company was also in compliance with all debt covenants pursuant to the CIBC credit facility at December 31, 2003. The agreement with CIBC also provides for $5.0 million of credit which can be utilized for financial derivative instruments used to hedge a portion of the Company's oil and gas production, currency exchange contracts and fixed price gas sales transactions with CIBC. No such credit was being utilized as of December 31, 2003.

The Company has $100 million outstanding in senior unsecured convertible notes which are due in 2021 and bear interest at a fixed annual rate of 4.75%, which is paid in cash on June 15 and December 15 of each year. In addition to the fixed interest, the Company will pay contingent interest to the holders of the notes if the average trading price of the notes for an established number of days equals 120% or more of the principal amount of the notes. The rate of contingent interest payable in respect to any six-month period will equal the greater of (1) a per annum rate equal to 5% of the Company's estimated per annum borrowing rate for senior non-convertible fixed-rate debt with a maturity date comparable to the notes or (2) 0.30% per annum. In no event may the contingent interest rate exceed 0.40% per annum. The Company paid contingent interest of $0.2 million on the notes during 2003 and will be required to pay an additional $0.2 million in contingent interest on June 15, 2004.

The senior unsecured convertible notes are general unsecured obligations, ranking on a parity in right of payment with all of Evergreen's existing and future senior indebtedness, and senior in right of payment with all of Evergreen's future subordinated indebtedness. The notes are due on December 15, 2021 but are redeemable at either the Company's option or the holder's option on other specified dates. The Company may redeem the notes at its option in whole or in part beginning on December 20, 2006 at 100% of their principal amount plus accrued and unpaid interest (including contingent interest). Holders of the notes may require the Company to repurchase the notes if a change in control of the Company occurs. Holders may also require the Company to repurchase all or part of the notes on December 20, 2006, December 15, 2011 and December 15, 2016 at a repurchase price of 100% of the principal amount of the notes plus accrued and unpaid interest (including contingent interest). On December 20, 2006, the Company may pay the repurchase price in cash, in shares of common stock, or in any combination of cash and common stock. On December 15, 2011 and December 15, 2016, the Company must pay the repurchase price in cash.

The senior unsecured convertible notes are convertible into shares of common stock of Evergreen under certain circumstances as discussed below at a conversion price of $25 per share, subject to certain adjustments. The notes can be converted at the option of the holder if for a specified period of time, the closing price of the Company's common stock exceeds 110% of the conversion price or if the average trading price of the notes for a specified period of time is less than 105% of an average conversion value as defined by the indenture governing the notes. Pursuant to this provision, at December 31, 2003 and through the date of this report, the notes were eligible to be converted into shares of common stock and as such, are currently considered potential common shares in the computation of fully diluted shares. No such conversions have occurred as of February 26, 2004. The notes may also be converted into shares of common stock of the Company at the election of the holder upon notice of redemption, or at any time the notes are rated by either Moody's Investors Service, Inc. or Standard & Poor's Rating Group and the credit rating initially assigned to the notes by either such rating agency is reduced by two or more ratings levels, or upon the occurrence of certain corporate transactions including a change in control or the distribution to current holders of the Company's common stock certain purchase rights or any other asset that has a value exceeding 10% of the sale price of the common stock on the day preceding the declaration date of the distribution of such assets.

The Company intends to refinance its revolving credit facilty prior to July 1, 2004, and increase the borrowing base from $200 million to $300 million. The Company has already received preliminary indications that a $300 million borrowing base is achievable. Additionally, the Company has announced that it intends to offer, subject to market and other conditions (including but not limited to obtaining a debt rating from rating agencies), $200 million of senior subordinated notes due 2012 in a private placement. The Company also has filed a shelf registration statement with the SEC for the issuance of debt securities, common or preferred stock, or other securities with an aggregate offering amount of up to $300 million. The Company also has available a shelf registration statement providing for the offering of common stock in connection with acquisitions of other businesses and assets, under which the aggregate offering amount available is $40 million.

The Company is well positioned to finance its cash requirements as needed through cash flow from operations, current credit facilities or equity offerings.

As of February 26, 2004, the Company had a total of $73.4 million available under its two lines of credit. Future cash flows will be influenced, among other factors, by the market price of natural gas as well as the number of producing properties on line. To the extent that gas prices decline, the Company's revenues, cash flows and earnings could be adversely affected, which could require the Company to rely more heavily on its revolving credit facility or other sources to fund its 2004 capital budget. The Company's management believes that if gas prices were to decline to a level that would have a material adverse effect on cash flows, the Company would continue to meet its working capital obligations and its 2004 capital budget (as discussed below) through its capacity under the revolving credit facilities. The Company has reduced its exposure to declines in natural gas prices throughout 2004 by hedging a portion of its natural gas production. See "—Hedging Transactions" below for more information.

Evergreen's capital budget for 2004 is estimated at $220 million. Of this total, approximately half is expected to be directed to Evergreen's coal bed methane operations in the Raton Basin, which includes approximately $34 million for infrastructure, approximately $47 million for the drilling and completion of 200 gross wells, approximately $27 million for recompletions and well equipment and approximately $1 million for leases and well service equipment. Evergreen plans to invest approximately $34 million in the Piceance and Uintah Basins, primarily for the drilling and completion of 55 gross wells, and approximately $34 million in the Western Canada Sedimentary Basin, primarily for the drilling and completion of 65 gross wells and associated infrastructure. Approximately $33 million will be directed to the Forest City Basin exploration project and approximately $2 million will be invested in Alaska.

Cash Flows and Capital Expenditures

Net cash flows provided by operating activities were $150.0 million for the year ended December 31, 2003 as compared to $55.4 million for the year ended December 31, 2002, an increase of $94.6 million or 171%. This increase was primarily attributable to a $127.5 million increase in net income before deferred taxes offset by a $49.8 million reduction in non-cash impairment charges. The year-over-year change in operating assets and liabilities from December 31, 2002 to December 31, 2003 also accounted for approximately $10.6 million of the increase in net cash flows provided by operating activities.

Net cash flows used in investing activities were $150.6 million for the year ended December 31, 2003, as compared to $114.8 million for the year ended December 31, 2002. The increase was primarily due to a larger investment in property and equipment.

Total capital expenditures for the year ended December 31, 2003 were $247.3 million. These capital costs included: $39.3 million to drill and complete 160 Raton Basin wells; $21.0 million for other Raton Basin projects, including remediation work; $35.4 million for the Raton Basin gas collection facilities; $45.6 million for exploration projects, consisting of $38.6 million for the Forest City Basin and $7.0 million for the Cook Inlet-Susitna Basin in Alaska; and $88.4 million for the Carbon acquisition, of which $82.2 million was from the issuance of Evergreen common stock and stock options. Of the remaining 2003 capital expenditures, approximately $6.5 million was for exploration and development operations in the Piceance, Uintah and Western Canada Sedimentary Basins and $11.1 million was used for other property acquisitions and equipment.

Net cash flows provided by financing activities were $3.6 million for the year ended December 31, 2003, as compared to $57.2 million for the year ended December 31, 2002. Due to the significant increase in net cash flows provided by operating activities, the Company was able to pay down outstanding indebtedness under its credit facilities by a net $6.4 million during 2003 even with an increase in capital expenditures. During 2002, the Company borrowed a net amount of $55.0 million, primarily to fund its capital expenditures in excess of the net cash flows provided by operating activities.

Contractual Obligations

The Company's contractual obligations include long-term debt, operating leases, transportation commitments, purchase commitments and other long-term liabilities. The following table lists the Company's significant contractual obligations at December 31, 2003.

	Payments Due By Period				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
			(in thousands)		
Revolving credit facilities	$149,373	$13,873	$135,500	$ —	$ —
Senior convertible notes	100,000	—	—	—	100,000
Operating leases	14,870	3,641	6,603	4,296	330
Transportation commitments	118,417	14,039	27,998	26,756	49,624
Other long-term liabilities	19,097	—	6,221	—	12,876
Product purchase agreements	6,929	6,929	—	—	—
Total contractual obligations	$408,686	$38,482	$176,322	$31,052	$162,830

See "—Source and Uses" above for discussion of the Company's revolving credit facilities and 4.75% senior convertible notes due 2021. For purposes of this table, the Company is assuming that the holders of the 4.75% senior convertible notes due 2021 will not exercise the conversion feature. In addition, periodic interest payments required under the revolving credit facilities and the 4.75% senior convertible notes due 2021 are not reflected in the table.

The Company leases its corporate offices in Denver, Colorado and leases other facilities in Calgary, Alberta, Canada; Ottawa, Kansas; Wasilla, Alaska and Price, Utah under the terms of operating leases, which expire beginning in 2004 and run through 2009. These office leases account for approximately $6.3 million of the $14.9 million reflected in the table above. The remaining operating lease commitments primarily represent vehicle and well service equipment leases, which expire beginning in 2004 and run through 2009.

Evergreen's firm transportation commitments in the Raton Basin are 127 MMcf of gross gas sales per day. The transportation commitments expire beginning in 2007 through 2014. The Company is also a party to various natural gas transportation contracts in Canada.

Other long-term liabilities include asset retirement obligations and non-current production and property taxes payable. For purposes of this table, the asset retirement obligation is reflected at its net present value. Neither the ultimate settlement amounts for the asset retirement obligations nor the timing of the settlements can be precisely determined. See Note 5 to the Consolidated Financial Statements.

At December 31, 2003, the Company had entered into agreements with various vendors to construct well and well service equipment valued at approximately $6.9 million.

Hedging Transactions

The Company may use derivative instruments to manage exposures to commodity prices, foreign currency and interest rate risks. The Company's objectives for holding derivatives are to achieve a consistent level of cash flow to support its capital budgeting and expenditure plans and to maximize internal rates of return for capital projects, including property acquisition investments. These transactions limit Evergreen's exposure to declines in prices, but also limit the benefits Evergreen would realize if prices increase. The Company does not enter into derivative instruments for trading purposes.

At December 31, 2003, the Company had the following natural gas commodity swaps in place (the instruments are denoted in MMBtu, which convert on an approximate 1-for-1 basis into Mcf). The weighted average prices of the commodity contracts have been adjusted for anticipated fuel use and regional price differentials.

Contract Period	Market	Volume in MMBtu/ day	Weighted Average Net Price/ MMBtu	Unrealized Losses at December 31, 2003 (in thousands)
Jan 04—Oct 04	Midcontinent	65,000	$4.86	$ 2,044
Jan 04—Dec 04	Midcontinent	50,000	$4.20	14,065
Jan 04—Dec 04	Northwest Pipeline—Rockies	3,000	$4.33	786
Jan 04—Dec 04	AECO—Canada	4,739	$4.63	587
				$17,482

Based on the calculated fair values at December 31, 2003, the Company expects to reclassify net losses of approximately $17.5 million into the statement of operations related to the above derivative contracts during the next 12 months.

The following table provides a reconciliation of the fair values of the Company's derivative commodity contracts at December 31, 2002 to the fair values at December 31, 2003.

	Fair Value of Commodity Contracts (in thousands)
Unrealized losses on contracts as of December 31, 2002	$ (2,733)
Net changes in contract fair value	(26,571)
Net contract losses recognized	11,822
Unrealized losses on contracts as of December 31, 2003	$(17,482)

Subsequent to December 31, 2003, the Company entered into the following commodity swap agreements:

Contract Period	Market	Volume in MMBtu/ day	Net Price per MMBtu
Feb 04—Mar 04	Midcontinent	10,000	$6.35

Income Taxes, Net Operating Losses and Tax Credits

As of December 31, 2003, the Company had net operating loss carryforwards for tax purposes of approximately $121.6 million, which expire beginning in 2009 through 2023. Additionally, the Company had tax credit carryforwards of approximately $8.8 million, of which $8.6 million relate to state tax credits that will expire beginning in 2003 through 2015.

The state tax credits are subject to limitation, and the Company has concluded that, based upon expected future results, the future reversals of taxable temporary differences and the tax benefits derived from the exercise of employee stock options, there is no reasonable assurance that the entire benefit of the tax credits can be used. Accordingly, a valuation allowance has been established. See Note 8 to the Consolidated Financial Statements for categories of book and tax timing differences.

Recent Accounting Pronouncements

In June 2001, the FASB issued SFAS No. 141, "Business Combinations" and SFAS No. 142, "Goodwill and Other Intangible Assets." SFAS No. 141 addresses accounting and reporting for business combinations and is effective for all business combinations initiated after June 30, 2001. SFAS No. 142 addresses the accounting and reporting for goodwill subsequent to acquisition and other intangible assets. The new standard eliminates the requirement to amortize acquired goodwill; instead, such goodwill is required to be reviewed at least annually for impairment. The new standard also requires that, at a minimum, all intangible assets be aggregated and presented as a separate line item in the balance sheet. The adoption of SFAS No. 141 and SFAS No. 142 had no impact on Evergreen's consolidated financial statements.

A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141 and SFAS No. 142 to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights held under lease or other contractual arrangements associated with extracting oil and gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, Evergreen has included the costs of such mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights held under lease or other contractual arrangements associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, Evergreen would be required to reclassify approximately $189 million at December 31, 2003 and $6.5 million at December 31, 2002 out of oil and gas properties and into a separate intangible assets line item. Evergreen's cash flows and results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with full-cost accounting rules.

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires the fair value of a liability for an asset retirement obligation to be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. SFAS No. 143 was effective for the Company on January 1, 2003. The adoption of this statement required the Company to record a non-cash expense, net of tax, of approximately $0.7 million as a cumulative effect of change in accounting principle in the first quarter of 2003. In addition, the Company recorded a non-current liability of approximately $4.6 million and an addition to oil and gas properties and the gas collection system of approximately $3.9 million in connection with the adoption of this statement effective January 1, 2003.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB No. 4, 44 and 64, Amendment of FASB No. 13, and Technical Corrections." SFAS No. 145 rescinds FASB No. 4 "Reporting Gains and Losses from Extinguishments of Debt Made to Satisfy Sinking-Fund Requirements." This statement also rescinds SFAS No. 44, "Accounting for Intangible Assets of Motor Carriers" and amends SFAS No. 13, "Accounting for Leases." This statement also amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. The Company adopted this statement on January 1, 2003. The adoption of this statement did not have a material effect on the Company's consolidated financial statements.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." SFAS No. 146 addresses accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (Including Certain Costs Incurred in a Restructuring)." SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized and measured initially at fair value when the liability is incurred. SFAS No. 146 was effective for exit or disposal activities that are initiated after December 31, 2002. The adoption of this statement did not have a material effect on the Company's consolidated financial statements.

During December 2003, the FASB issued Interpretation No. 46R, "Consolidation of Variable Interest Entities" ("FIN 46"), which requires the consolidation of certain entities that are determined to be variable interest entities ("VIE's"). An entity is considered to be a VIE when either (i) the entity lacks sufficient equity to carry on its principal operations, (ii) the equity owners of the entity cannot make decisions about the entity's activities or (iii) the entity's equity neither absorbs losses or benefits from gains. Evergreen owns no interests in variable interest entities, and therefore this new interpretation will not affect the Company's consolidated financial statements.

In May 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS No. 149 amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 149 is generally effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. The adoption of this statement did not have a material effect on the Company's consolidated financial statements.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity." SFAS No. 150 establishes standards for how an issuer measures certain financial instruments with characteristics of both liabilities and equity and requires that an issuer classify a financial instrument within its scope as a liability (or asset in some circumstances). SFAS No. 150 was effective for financial instruments entered into or modified after May 31, 2003 and otherwise was effective and adopted by the Company on July 1, 2003. As the Company has no such instruments, the adoption of this statement did not have an impact on the Company's consolidated financial statements.

Critical Accounting Policies and Estimates

The Company believes the following critical accounting policies affect its more significant judgments and estimates used in the preparation of its Consolidated Financial Statements.

Reserve Estimates: The Company's estimates of oil and natural gas reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future oil and natural gas prices, future operating costs, severance, ad valorem and excise taxes, development costs and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected there from may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Company's oil and gas properties and the rate of depletion of the oil and gas properties. Actual production, revenues and expenditures with respect to the Company's reserves will likely vary from estimates, and such variances may be material.

The Company's estimated proved reserves at December 31, 2003, 2002 and 2001 were either audited or prepared by independent petroleum engineering consultants Netherland, Sewell & Associates, Inc. Raton Basin reserve and present value estimates have been audited by Netherland, Sewell & Associates, Inc. for the years ended December 31, 2003, 2002 and 2001. Reserve and present value estimates for the Piceance, Uintah and Western Canada Sedimentary Basins have been prepared by Netherland, Sewell & Associates, Inc. for the year ended December 31, 2003, the only period for which those estimates were included.

Property, Equipment and Depreciation: The Company follows the full-cost method of accounting for oil and gas properties. Under this method, all productive and nonproductive costs incurred in connection with the exploration for and development of oil and gas reserves are capitalized. Such capitalized costs include lease acquisition, geological and geophysical work, delay rentals, drilling, completing and equipping oil and gas wells, and salaries, benefits and other internal salary-related costs directly attributable to these activities. Costs associated with production and general corporate activities are expensed in the period incurred. Interest costs related to unproved properties and properties under development are also capitalized to oil and gas properties. Normal dispositions of oil and gas properties are accounted for as adjustments of capitalized costs, with no gain or loss recognized.

Gas collection and support equipment are stated at cost. Depreciation and amortization for the gas collection systems, with the exception of the gas compressor facilities, is computed on the units-of-production method based upon total reserves of the field. Gas compressor facilities and other support equipment are depreciated using the straight-line method over the estimated useful lives of the assets of three to 30 years.

The Company is required to review the carrying value of its oil and gas properties each quarter under the full cost accounting rules of the SEC. Under these rules, capitalized costs of proved oil and gas properties, as adjusted for asset retirement obligations, may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10%. Application of the ceiling test generally requires pricing future revenue at the unescalated prices in effect as of the last day of the quarter, with effect given to the Company's cash flow hedge positions, and requires a write-down for accounting purposes if the ceiling is exceeded. Unproved oil and gas properties are not amortized, but are assessed for impairment either individually or on an aggregated basis using a comparison of the carrying values of the unproved properties to net future cash flows.

Derivative Financial Instruments: Effective January 2001, derivative financial instruments utilized to manage or reduce commodity price risk related to the Company's production are accounted for under the provisions of SFAS No. 133, "Accounting for Derivative Instruments and for Hedging Activities." Under this statement, all derivatives are carried on the balance sheet at fair value.

The estimated fair values of the Company's derivative instruments require substantial judgment. The Company estimates the fair values of its commodity swaps using a discounted future cash flow technique and estimates the fair values of its commodity costless collars using the Black Scholes option-pricing model. The pricing and discounting variables used in the Company's valuations are sensitive to market volatility as well as changes in future price forecasts, regional price differentials and interest rates. Actual gains or losses recognized may be materially different than what the Company has estimated at December 31, 2003 and will depend solely on the regional price indexes of the commodities on the specified settlement dates provided by the derivative contracts.

Valuation of Deferred Tax Assets: The Company uses the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are determined based on differences between the financial statement carrying values and their respective income tax bases (temporary differences). Future income tax assets and liabilities are measured using the tax rates expected to be in effect when the temporary differences are likely to reverse. The effect on future income tax assets and liabilities of a change in tax rates is included in operations in the period in which the change is enacted. The amount of future income tax assets recognized is limited to the amount of the benefit that is more likely than not to be realized.

In assessing the future realization of deferred tax assets, the Company considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. In order to fully realize its net deferred tax asset at December 31, 2003, the Company will need to generate future taxable income of approximately $121.6 million prior to the expiration of the net operating loss carryforwards beginning in 2009 to 2023. Based upon the level of historical taxable income and projections for future taxable income over the periods which the deferred tax assets are deductible, management believes it is more likely than not that it will realize the benefits of these deductible differences, net of the existing valuation allowances at December 31, 2003. The amount of the deferred tax asset considered realizable, however, could be reduced in the near term if estimates of future taxable income during the carryforward periods are reduced.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

The Company measures its exposure to market risk at any point in time by comparing its open positions to a market risk of fair value. The market prices the Company uses to determine fair value are based on management's best estimates, which consider various factors including closing exchange prices, volatility factors and the time value of money. At December 31, 2003, the Company was exposed to some market risk with respect to natural gas prices, long-term debt and foreign currency; however, management did not believe such risk to be material.

Commodity Risk. The Company's major market risk exposure is in the pricing applicable to its natural gas production. Realized pricing is primarily driven by the prevailing price for crude oil and spot prices applicable to Evergreen's oil and natural gas production. Historically, prices received for gas production have been volatile and unpredictable. Pricing volatility is expected to continue.

The Company periodically enters into agreements to hedge its natural gas production when market conditions are deemed favorable in order to manage price fluctuations and achieve a more predictable cash flow. The Company may use fixed-price physical delivery contracts and derivative instruments to manage exposures to commodity prices. The Company does not enter into derivative instruments for trading purposes.

Assuming production, the percent of oil and gas hedged and the average realized market price of the unhedged oil and gas sold remained unchanged from the year ended December 31, 2003, a hypothetical 10% decline in the average market price the Company realized during the year ended December 31, 2003 on unhedged production would reduce the Company's oil and natural gas revenues by approximately $5.6 million on an annual basis.

Interest Rate Risk. At December 31, 2003, Evergreen had long-term debt outstanding of $249.4 million. The weighted average interest rate of 2.82% on the Company's revolving credit facilities, under which $149.4 million in indebtedness was outstanding at December 31, 2003 are variable. A 10% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2003 would equal approximately 28 basis points. Such an increase in interest rates would impact Evergreen's annual interest expense by approximately $0.4 million, assuming borrowed amounts under the credit facilities remained at $149.4 million.

The $100 million convertible notes due 2021 have a fixed interest rate of 4.75%; however, up to an additional 0.40% may be paid as contingent interest if certain conditions are met. Accordingly, the Company's annual interest payment on the $100 million 4.75% convertible notes due 2021 will be a minimum of $4.75 million and a maximum of $5.15 million.

Foreign Currency Risk. Evergreen completed the acquisition of Carbon effective October 29, 2003 and now conducts business in Canada through its Canadian subsidiary where the Canadian dollar has been designated as the functional currency. As such, the Company is now subject to foreign currency exchange risk on cash flows relating to sales, expenses, financing and investing transactions. Evergreen's net assets, revenue and expense accounts from its foreign operations in Canada are based on the U.S. dollar equivalent of such amounts measured in the Canadian dollar. Assets and liabilities of these foreign operations are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rates during the reporting period.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements

	Page
Report of Independent Certified Public Accountants	F-1
Consolidated Balance Sheets as of December 31, 2003 and 2002	F-2
Consolidated Statements of Operations for the Years Ended December 31, 2003, 2002 and 2001	F-3
Consolidated Statements of Stockholders' Equity for the Years Ended December 31, 2003, 2002, and 2001	F-4
Consolidated Statements of Cash Flows for the Years Ended December 31, 2003, 2002, and 2001	F-5
Consolidated Statements of Comprehensive Income (Loss) for the Years Ended December 31, 2003, 2002, and 2001	F-6
Notes to Consolidated Financial Statements	F-7 to F-39

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

Not Applicable.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Evaluation of disclosure controls and procedures

The Company's Chief Executive Officer and the Chief Financial Officer evaluated the effectiveness of the Company's disclosure controls and procedures as of December 31, 2003 in accordance with Rule 13a-15 under the Exchange Act. Based on their evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that the Company's disclosure controls and procedures enable the Company to:

- record, process, summarize and report within the time periods specified in the Security and Exchange Commission's rules and forms, information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act; and
- accumulate and communicate to management, as appropriate to allow timely decisions regarding required disclosure, information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act.

(b) Changes in internal control over financial reporting

There were no changes in the Company's internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the quarter ended December 31, 2003 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART III

The information required by Items 10, 11, 12, 13 and 14 under Part III of Form 10-K is incorporated herein by reference to Evergreen's definitive Proxy Statement to be filed in connection with the Annual Meeting of Stockholders to be held May 7, 2004.

PART IV

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

(a)(1) See Index to Consolidated Financial Statements at Item 8.

(a)(2) All other schedules have been omitted because the required information is inapplicable or is shown in the Notes to the Consolidated Financial Statements.

(a)(3) Exhibits:

2.1	Agreement and Plan of Reorganization dated as of March 31, 2003 between the Company and Carbon Energy Corporation: Incorporated by reference to Exhibit 99.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2003.
3.1	Articles of Incorporation, as amended: Incorporated by reference to Exhibit 3.1 to the Company's Registration Statement on Form S-1, Commission File No. 33-273035, by reference to Exhibit I to the Company's Current Report on Form 8-K dated December 9, 1994 and by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed June 8, 1998.
3.2	Articles of Amendment to Articles of Incorporation stating terms of redeemable preferred stock: Incorporated by reference to Exhibit 3.2 to the Company's Annual Report on Form 10-K for the year ended December 31, 2000.
3.3	Articles of Amendment to Articles of Incorporation increasing the number of authorized shares of Company common stock.
3.4	Bylaws: Incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed June 8, 1998.
3.5	Amendment to Section 2.13 of the Bylaws (Notice of Shareholder Nominations).
4.1	Shareholders' Rights Agreement: Incorporated by reference to Exhibit 2 to the Company's Current Report on Form 8-K dated July 7, 1997.
4.2	Form of Global Note for 4.75% Senior Convertible Notes due December 15, 2021 (included in Exhibit 4.3).
4.3	Indenture, dated December 18, 2001: Incorporated by reference to Exhibit 4.4 to the Company's Annual Report on Form 10-K for the year ended December 31, 2001.
4.4	Registration Rights Agreement, dated December 18, 2001: Incorporated by reference to Exhibit 4.3 to the Company's Annual Report on Form 10-K for the year ended December 31, 2001.
10.1	Financing Commitment, dated as of May 14, 2003, among Evergreen Resources Canada, Ltd. (successor to Carbon Energy Canada Corporation) and Canadian Imperial Bank of Commerce.
10.2	Second Amended and Restated Credit Agreement by and among Evergreen Resources, Inc. and Hibernia National Bank, BNP Paribas, Wells Fargo Bank, NA, BankOne, NA, Fleet National Bank, Bank of Scotland, and Wachovia National Bank Association dated May 31, 2002: Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002.
10.3	Firm Transportation Service Agreement Rate Schedule TF-1 between Colorado Interstate Gas Company and Primero Gas Marketing Company, dated August 22, 1997: Incorporated by reference to Exhibit 10.2 to the Company's Registration Statement on Form S-3 filed on November 21, 1997, Commission File No. 333-40817.
10.4	Deeds of Variation between The Secretary of State for Trade and Industry and Evergreen Resources (UK) Limited dated January 9, 1997: Incorporated by reference to Exhibit 10.6 of the Company's Registration Statement on Form S-3 filed on November 21, 1997, Commission File No. 333-40817.
10.5	Evergreen Resources, Inc. Initial Stock Option Plan: Incorporated by reference to the exhibit accompanying the Company's Definitive Proxy Statement on Schedule 14A filed on April 20, 1998.*

10.6 Firm Transportation Service Agreement Rate Schedule TF-1 between Colorado Interstate Gas Company and Consolidated Industrial Services, Inc., dated March 20, 1997: Incorporated by reference to Exhibit 10.5 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1998.

10.7 Firm Transportation Service Agreement Rate Schedule TF-1 between Colorado Interstate Gas Company and Amoco Energy Trading Corporation, dated November 1, 1997: Incorporated by reference to Exhibit 10.6 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1998.

10.8 2000 Stock Incentive Plan of Evergreen Resources, Inc.: Incorporated by reference to Exhibit A to the Company's definitive proxy materials on Schedule 14A filed on May 1, 2000.*

10.9 Agreement for Purchase and Sale dated September 19, 2000, by and between Apache Canyon Gas, L.L.C., as Seller and Evergreen Resources, Inc. as Buyer: Incorporated by reference to Exhibit 2.1 to the Company's Form 8-K filed on October 5, 2000.

10.10 Agreement for Purchase and Sale dated September 19, 2000, by and between Apache Canyon Gas, L.L.C., as Seller and Evergreen Resources, Inc. as Buyer: Incorporated by reference to Exhibit 2.2 to the Company's Form 8-K filed on October 5, 2000.

10.11 Change in Control Agreement dated March 1, 2002 by and between Evergreen Resources, Inc. and Mark S. Sexton: Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2002.*

10.12 Change in Control Agreement dated March 1, 2002 by and between Evergreen Resources, Inc. and Dennis R. Carlton: Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2002.*

10.13 Change in Control Agreement dated March 1, 2002 by and between Evergreen Resources, Inc. and Kevin R. Collins: Incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2002.*

21.1 Subsidiaries of registrant.

22.1 Reserve Audit Report (Raton Basin) audited by Netherland, Sewell & Associates, Inc.

22.2 Reserve Report (ERI Piceance/Uintah Basins) prepared by Netherland, Sewell & Associates, Inc.

22.3 Reserve Report (Evergreen Resources Canada, Ltd.) prepared by Netherland, Sewell & Associates, Inc.

23.1 Consent of Independent Certified Public Accountants.

23.2 Consent of Netherland, Sewell & Associates, Inc., independent petroleum engineering consultants.

24.1 Power of Attorney: contained on signature page.

31.1 Certification Pursuant to Rule 13a-14(a) or 15d-14(a) of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification Pursuant to Rule 13a-14(a) or 15d-14(a) of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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* Compensatory plan or arrangement

(b) Reports on Form 8-K.

On October 29, 2003, Evergreen Resources Inc. furnished a Form 8-K under Item 12 to report its financial results for its third quarter ended September 30, 2003.

On November 12, 2003, Evergreen Resources, Inc. filed a Form 8-K under Item 5 to announce that Evergreen Resources, Inc.'s $100 million principal amount of 4.75% Senior Convertible Notes due 2021 became convertible into Evergreen's common stock on November 11, 2003 and will remain convertible through February 12, 2004, as a result of the trading price of Evergreen's common stock exceeding certain thresholds set forth in the indenture governing the notes.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

EVERGREEN RESOURCES, INC.

Date: February 27, 2004

By: /s/ MARK S. SEXTON

Mark S. Sexton
President and Chief Executive Officer
(Principal Executive Officer)

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Mark S. Sexton and Kevin R. Collins, and each of them, as true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all which said attorneys-in-fact and agents or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Date: February 27, 2004

/s/ MARK S. SEXTON

Mark S. Sexton
President, Chief Executive Officer and Director
(Principal Executive Officer)

Date: February 27, 2004

/s/ KEVIN R. COLLINS

Kevin R. Collins, Executive Vice President—Finance, Chief Financial Officer, Secretary and Treasurer
(Principal Financial and Accounting Officer)

Date: February 27, 2004

/s/ ALAIN G. BLANCHARD

Alain G. Blanchard, Director

Date: February 27, 2004

/s/ DENNIS R. CARLTON

Dennis R. Carlton, Director

Date: February 27, 2004	/s/ ROBERT J. CLARK Robert J. Clark, Director
Date: February 27, 2004	/s/ LARRY D. ESTRIDGE Larry D. Estridge, Director
Date: February 27, 2004	/s/ ANDREW D. LUNDQUIST Andrew D. Lundquist, Director
Date: February 27, 2004	/s/ JOHN J. RYAN III John J. Ryan III, Director
Date: February 27, 2004	/s/ SCOTT D. SHEFFIELD Scott D. Sheffield, Director
Date: February 27, 2004	/s/ ARTHUR L. SMITH Arthur L. Smith, Director

Report of Independent Certified Public Accountants

To the Stockholders and Board of Directors
Evergreen Resources, Inc.
Denver, Colorado

We have audited the accompanying consolidated balance sheets of Evergreen Resources, Inc. and subsidiaries as of December 31, 2003 and 2002 and the related consolidated statements of operations, stockholders' equity, cash flows, and comprehensive income (loss) for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Evergreen Resources, Inc. and subsidiaries at December 31, 2003 and 2002 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 5 to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations. As discussed in Note 1 to the consolidated financial statements, effective January 1, 2001, the Company changed its method of accounting for derivative instruments.

/s/ BDO SEIDMAN, LLP

Houston, Texas
February 13, 2004

Evergreen Resources, Inc.

Consolidated Balance Sheets

	December 31, 2003	December 31, 2002
	(in thousands)	
ASSETS		
Current:		
Cash and cash equivalents	$ 3,820	$ 871
Accounts receivable	25,708	17,684
Other current assets	2,817	1,384
Total current assets	32,345	19,939
Property and equipment, at cost:		
Oil and gas properties, full cost method of accounting:		
Proved, net of accumulated depletion of $74,671 and $54,061	575,026	384,232
Unproved	85,841	29,163
Net oil and gas properties	660,867	413,395
Other property and equipment, net of accumulated depreciation, and amortization of $28,448 and $20,370	201,771	167,021
Net property and equipment	862,638	580,416
Other assets	10,103	6,406
	$905,086	$606,761
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 4,697	$ 4,109
Amounts payable to oil and gas property owners	10,557	5,871
Production and property taxes payable	9,407	5,731
Derivative instruments	17,821	1,454
Accrued liabilities and other	14,214	7,912
Total current liabilities	56,696	25,077
Notes payable	149,373	136,000
Senior convertible notes	100,000	100,000
Deferred income taxes	92,355	27,666
Asset retirement obligation	12,876	—
Production taxes payable and other	6,221	4,328
Total liabilities	417,521	293,071
Minority interest in subsidiaries	4,637	1,262
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $1.00 par value; shares authorized, 24,900; none outstanding	—	—
Common stock, $0.005 stated value; shares authorized, 100,000; shares issued and outstanding 42,937 and 38,105	215	190
Additional paid-in capital	370,352	262,083
Retained earnings	123,099	50,471
Accumulated other comprehensive loss	(10,738)	(316)
Total stockholders' equity	482,928	312,428
	$905,086	$606,761

See accompanying Notes to Consolidated Financial Statements.

Evergreen Resources, Inc.

Consolidated Statements of Operations

	Years Ended December 31,		
	2003	2002	2001
	(in thousands, except per share data)		
Revenues:			
Oil and natural gas revenues	$215,460	$111,550	$119,745
Interest and other	980	576	1,025
Total revenues	216,440	112,126	120,770
Expenses:			
Lease operating expense	20,970	16,161	12,228
Transportation costs	14,486	12,233	9,524
Production and property taxes	11,096	5,960	5,472
Depreciation, depletion and amortization	26,913	20,916	16,212
Impairment of international properties	1,712	51,546	—
General and administrative expenses	14,619	9,226	6,985
Interest expense	8,251	8,345	8,331
Other, net	2,874	645	653
Total expenses	100,921	125,032	59,405
Income (loss) before income taxes and cumulative effect of change in accounting principle	115,519	(12,906)	61,365
Income tax provision:			
Current	221	—	—
Deferred	41,957	(4,582)	22,838
Total income tax provision	42,178	(4,582)	22,838
Income (loss) before cumulative effect of change in accounting principle	73,341	(8,324)	38,527
Cumulative effect of change in accounting principle, net of tax	713	—	—
Net income (loss)	$ 72,628	$ (8,324)	$ 38,527
Basic income (loss) per common share:			
Income (loss) before cumulative effect of change in accounting principle	$ 1.86	$ (0.22)	$ 1.04
Cumulative effect of change in accounting principle, net of tax	0.02	—	—
Net income (loss)	$ 1.84	$ (0.22)	$ 1.04
Diluted income (loss) per common share:			
Income (loss) before cumulative effect of change in accounting principle	$ 1.79	$ (0.22)	$ 0.99
Cumulative effect of change in accounting principle, net of tax	0.02	—	—
Net income (loss)	$ 1.77	$ (0.22)	$ 0.99

See accompanying Notes to Consolidated Financial Statements.

Evergreen Resources, Inc.

Consolidated Statements of Stockholders' Equity

Years Ended December 31, 2003, 2002 and 2001

	Common Stock $0.005 Stated Value		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholders' Equity
	Shares	Amount				
			(in thousands)			
Balance, January 1, 2001	36,656	$183	$247,377	$ 20,268	$ (976)	$266,852
Issuance of common stock for services	60	—	898	—	—	898
Exercise of stock options and purchase warrants, net	1,007	5	3,956	—	—	3,961
Common stock exchanged as payment for exercise of stock purchase options	(88)	—	(1,653)	—	—	(1,653)
Tax benefit from exercise of stock options and warrants	—	—	5,534	—	—	5,534
Issuance of common stock for property interests	79	1	1,219	—	—	1,220
Common stock repurchase	(20)	(1)	(353)	—	—	(354)
Other comprehensive loss	—	—	—	—	(45)	(45)
Net income	—	—	—	38,527	—	38,527
Balance, December 31, 2001	37,694	188	256,978	58,795	(1,021)	314,940
Issuance of common stock for services	28	—	488	—	—	488
Exercise of stock options and purchase warrants, net	413	2	3,702	—	—	3,704
Common stock exchanged as payment for exercise of stock purchase options	(30)	—	(636)	—	—	(636)
Deferred stock compensation and other, net	—	—	105	—	—	105
Tax benefit from exercise of stock options and warrants	—	—	1,446	—	—	1,446
Other comprehensive income	—	—	—	—	705	705
Net loss	—	—	—	(8,324)	—	(8,324)
Balance, December 31, 2002	38,105	190	262,083	50,471	(316)	312,428
Carbon Energy Corporation acquisition:						
Issuance of common stock	3,465	18	78,702	—	—	78,720
Exchanged stock options	—	—	3,487	—	—	3,487
Issuance of common stock for property interests	498	3	12,397	—	—	12,400
Issuance of common stock for services	41	—	14	—	—	14
Exercise of stock options and purchase warrants, net	831	4	7,484	—	—	7,488
Common stock exchanged as payment for exercise of stock purchase options	(3)	—	(100)	—	—	(100)
Deferred stock compensation and other, net	—	—	1,656	—	—	1,656
Tax benefit from exercise of stock options and warrants	—	—	4,629	—	—	4,629
Other comprehensive loss	—	—	—	—	(10,422)	(10,422)
Net income	—	—	—	72,628	—	72,628
Balance, December 31, 2003	42,937	$215	$370,352	$123,099	$(10,738)	$482,928

See accompanying Notes to Consolidated Financial Statements.

Evergreen Resources, Inc.

Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2003	2002	2001
	(in thousands)		
Increase (Decrease) in Cash and Cash Equivalents			
Operating activities:			
Net income (loss)	$ 72,628	$ (8,324)	$ 38,527
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	26,913	20,916	16,212
Impairment of international properties	1,712	51,546	—
Deferred income taxes	41,957	(4,582)	22,838
Gain on sale of stock in affiliated company	(2,627)	—	—
Other	3,879	964	479
Changes in operating assets and liabilities, net of effects of acquisitions:			
Accounts receivable	(5,141)	(6,680)	5,370
Other current assets	(1,003)	154	(443)
Change in designated cash	—	—	2,376
Accounts payable	(3,050)	(1,898)	(141)
Amounts payable to oil and gas property owners	3,139	1,792	1,492
Production and property taxes payable	6,177	662	191
Accrued liabilities and other	5,367	844	4,704
Net cash provided by operating activities	149,951	55,394	91,605
Investing activities:			
Investment in property and equipment	(143,981)	(126,617)	(120,681)
Proceeds from sale of equipment	1,181	10,003	—
Carbon acquisition transaction costs	(6,151)	—	—
Exercise of stock purchase warrants in affiliated company	(2,250)	—	—
Proceeds from sale (purchase) of investments in affiliated company	4,877	2,000	(1,515)
Proceeds from sale of investment in common stock	2,780	—	—
Deposits on property and equipment	(5,904)	—	—
Other	(1,123)	(152)	(351)
Net cash used in investing activities	(150,571)	(114,766)	(122,547)
Financing activities:			
Net (payments on) proceeds from notes payable	(6,384)	55,000	(68,748)
Proceeds from issuance of common stock, net	7,371	2,936	2,308
Net proceeds from minority interest owners	2,582	—	—
Debt issue costs	—	(738)	(3,241)
Proceeds from senior convertible notes	—	—	100,000
Common stock repurchase	—	—	(354)
Net cash provided by financing activities	3,569	57,198	29,965
Effect of exchange rate changes on cash and cash equivalents	—	21	(33)
Increase (decrease) in cash and cash equivalents	2,949	(2,153)	(1,010)
Cash and cash equivalents, beginning of year	871	3,024	4,034
Cash and cash equivalents, end of year	$ 3,820	$ 871	$ 3,024

See accompanying Notes to Consolidated Financial Statements.

EVERGREEN RESOURCES, INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Years Ended December 31,		
	2003	2002	2001
	(in thousands)		
Net income (loss)	$ 72,628	$(8,324)	$ 38,527
Cumulative effect of change in accounting principle, net of tax of $273	—	—	(446)
Derivative instruments:			
Change in fair value	(26,571)	(9,268)	14,177
Reclassification adjustment for losses (gains) included in operations	11,822	6,738	(13,662)
Derivative instruments, before taxes	(14,749)	(2,530)	515
Related income tax effect	5,411	898	(198)
Derivative instruments, net of tax	(9,338)	(1,632)	317
Available-for-sale securities:			
Change in fair value	594	(319)	1,046
Reclassification adjustment for realized gains included in operations	(1,321)	—	—
Available-for-sale securities before taxes	(727)	(319)	1,046
Related income tax effect	276	113	(389)
Available-for-sale instruments, net of tax	(451)	(206)	657
Foreign currency translation adjustments:			
Unrealized gain (loss)	363	3,534	(573)
Reclassification adjustment for gains included in operations	(996)	(991)	—
	(633)	2,543	(573)
Comprehensive income (loss)	$ 62,206	$(7,619)	$ 38,482

See accompanying Notes to Consolidated Financial Statements.

Evergreen Resources, Inc.

Notes to Consolidated Financial Statements

Years ended December 31, 2003, 2002 and 2001

(1) SUMMARY OF ACCOUNTING POLICIES

Business

Evergreen Resources, Inc. ("Evergreen" or "the Company") is a Colorado corporation organized on January 14, 1981. Evergreen is an independent energy company primarily engaged in the operation, development, production, exploration and acquisition of unconventional natural gas properties. Evergreen is one of the leading developers of coal bed methane reserves in the United States. Its current operations are principally focused on developing and expanding its coal bed methane project located in the Raton Basin in southern Colorado. Evergreen has initiated coal bed methane projects in the Cook Inlet-Susitna Basin in Alaska and in the Forest City Basin in eastern Kansas. Effective October 29, 2003, Evergreen completed its acquisition of Carbon Energy Corporation ("Carbon"). Carbon's properties are located in the Piceance Basin in western Colorado, the Uintah Basin in eastern Utah, and the Western Canada Sedimentary Basin in south-central Alberta. See Note 3.

Consolidation

The financial statements include the accounts of Evergreen and its wholly-owned subsidiaries. The financial statements also include the accounts of Evergreen's majority owned subsidiaries consisting of an 85% ownership interest in Lorencito Gas Gathering, LLC and an approximate 75% ownership interest in Long Canyon Gas Company, LLC (see Note 3). All significant intercompany balances and transactions have been eliminated in consolidation.

The Company also has a 40% ownership in Argos Evergreen Limited, a Falkland Islands company, which owns offshore drilling rights in the North Falklands Basin. This investment is accounted for by the equity method of accounting. The Company has no interests in any other unconsolidated entities, nor does it have any off-balance sheet financing arrangements (other than operating leases) or any unconsolidated special purpose entities.

Use of Estimates

The preparation of these consolidated financial statements requires the use of certain estimates by management in determining the Company's assets, liabilities, revenues and expenses. Actual results could differ from such estimates. Depreciation, depletion and amortization of oil and gas properties and the impairment of oil and gas properties are determined using estimates of oil and gas reserves. There are numerous uncertainties in estimating the quantity of reserves and in projecting the future rates of production and timing of development expenditures, including future costs to dismantle, dispose, and restore the Company's properties. Oil and gas reserve engineering must be recognized as a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way. Proved reserves of oil and natural gas are estimated quantities that geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known reservoirs under existing conditions.

Property and Equipment

The Company follows the full-cost method of accounting for oil and gas properties. Under this method, all productive and nonproductive costs incurred in connection with the exploration for and development of oil and gas reserves are capitalized. Such capitalized costs include lease acquisition,

(1) SUMMARY OF ACCOUNTING POLICIES (Continued)

geological and geophysical work, delay rentals, drilling, completing and equipping oil and gas wells, including salaries, benefits and other internal salary-related costs directly attributable to these activities. Evergreen, through its various subsidiaries, performs its own fracture stimulation treatments and constructs the majority of its gas collection systems. For the years ended December 31, 2003, 2002 and 2001, Evergreen capitalized $5.3 million, $3.4 million and $1.9 million of general and administrative costs, respectively. Costs associated with production and general corporate activities are expensed in the period incurred. Interest costs related to unproved properties and properties under development are also capitalized to oil and gas properties (see Note 16). Approximately $1.3 million, $1.4 million and $1.2 million of interest was capitalized during the years ended December 31, 2003, 2002 and 2001, respectively.

If the net investment in oil and gas properties in a cost center, as adjusted for asset retirement obligations, exceeds an amount equal to the sum of (1) the standardized measure of discounted future net cash flows from estimated proved reserves (see Note 16) and (2) the lower of cost or fair market value of properties in process of development and unexplored acreage, the excess is charged to expense as additional depletion. The standardized measure is calculated using a 10% discount rate and is based on unescalated prices in effect at year-end with effect given to the Company's cash flow hedge positions. Normal dispositions of oil and gas properties are accounted for as adjustments of capitalized costs, with no gain or loss recognized.

Depreciation and depletion of proved oil and gas properties is computed on the units-of-production method based upon estimates of proved reserves with oil and gas being converted to a common unit of measure based on their relative energy content.

Unproved oil and gas properties, including any related capitalized interest expense, are not amortized, but are assessed for impairment either individually or on an aggregated basis. The costs of certain unevaluated leasehold acreage and wells drilled are not being amortized. Costs not being amortized are periodically assessed for possible impairments or reductions in value. If a reduction in value has occurred, costs being amortized are increased or a charge is made against earnings for those operations where a reserve base is not yet established.

Gas collection and support equipment are stated at cost. Depreciation and amortization for the gas collection system, with the exception of the gas compressor facilities, is computed on the units-of-production method based upon total reserves of the field. Gas compressor facilities and other support equipment are depreciated using the straight-line method over the estimated useful lives of the assets of three to 30 years.

Segment Information

In accordance with Statement of Financial Accounting Standards ("SFAS") No. 131, "Disclosures about Segments of an Enterprise and Related Information," the Company determined, through a review of its geographic locations, organizational structure and business activities from which it earns revenues, that it has one industry segment, the exploration and production of oil and gas. Geographically, the Company has operations in the United States and in Canada. Of the Company's total revenues, approximately $2.3 million were from the Company's Canadian operations during the

(1) SUMMARY OF ACCOUNTING POLICIES (Continued)

year ended December 31, 2003. At December 31, 2003, approximately $82.8 million of the Company's net oil and gas properties and gas collection assets were located in Canada.

Long-Lived Assets

The Company applies SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets", to long-lived assets not included in oil and gas properties. Under SFAS No. 144, all long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying value may not be recoverable. The carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. An impairment loss is recognized when the carrying value of a long-lived asset is not recoverable and exceeds its fair value.

Amounts Payable to Oil and Gas Property Owners

Amounts payable to oil and gas property owners represent production revenue that the Company, as operator, is collecting and distributing to revenue interest owners.

Minority Interest

The minority interest of $4.6 million on the Company's consolidated balance sheet at December 31, 2003 represents a 15% outside ownership interest in Lorencito Gas Gathering, LLC and an approximate 25% outside ownership interest in Long Canyon Gas Company, LLC (see Note 3). The minority interest in these subsidiaries' net income for the years ended December 31, 2003 and 2002 of approximately $1.3 million and $4,000, respectively, is included in other expense in the Company's consolidated statements of operations.

Income Taxes

The Company follows the liability method of accounting for income taxes under which deferred tax assets and liabilities are recognized for future tax consequences. Accordingly, deferred tax assets and liabilities are determined based on the temporary differences between the financial statement and tax bases of assets and liabilities, using enacted tax rates in effect for the year in which the differences are expected to reverse.

Environmental Matters

Environmental costs are expensed or capitalized depending on their future economic benefit. Costs that relate to an existing condition caused by past operations with no future economic benefit are expensed. Liabilities for future expenditures of a non-capital nature are recorded when future environmental expenditures and/or remediation is deemed probable and the costs can be reasonably estimated. Costs of future expenditures for environmental remediation obligations are not discounted to their present value.

(1) SUMMARY OF ACCOUNTING POLICIES (Continued)

Net Income (Loss) Per Share

The Company applies the provisions of SFAS No. 128, "Earnings Per Share", for the calculation of "Basic" and "Diluted" earnings (loss) per share. Basic earnings (loss) per share includes no dilution and is computed by dividing income (loss) available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted earnings (loss) per share reflects the potential dilution of securities that could share in the earnings of the Company.

Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Designated Cash

Through September 30, 2001, the Company recorded designated cash equal to the production taxes its operating subsidiary, Evergreen Operating Corporation ("EOC"), had withheld from Evergreen, third party working interest owners and royalty owners. Effective in the fourth quarter of 2001, the Company maintains a separate cash account with a balance approximating the production taxes EOC has withheld from third party working interest owners and royalty owners that has not been remitted to the taxing authorities.

Revenue Recognition

Oil and natural gas revenues are recorded using the sales method, whereby the Company recognizes oil and natural gas revenue based on the amount of oil and gas sold to purchasers.

Debt Issue Costs

The Company had approximately $5.3 million of debt issue costs at December 31, 2003 and 2002, net of accumulated amortization of $1.8 million and $1.4 million, respectively, which are included in other assets in the Company's consolidated balance sheet. The debt issue costs are being amortized using the interest method over the term of the associated long-term debt.

Accumulated Other Comprehensive Income (Loss)

The Company has elected to report comprehensive income (loss) in a consolidated statement of comprehensive income (loss). Comprehensive income (loss) is composed of net income (loss) and all changes to stockholders' equity, except those due to investments by stockholders, changes in paid-in

(1) SUMMARY OF ACCOUNTING POLICIES (*Continued*)

capital and distributions to stockholders. The following table identifies the components of accumulated other comprehensive loss for each of the periods presented:

	December 31, 2003	December 31, 2002
	(in thousands)	
Accumulated foreign currency translation gain	$ 363	$ 994
Unrealized loss on derivatives, net of tax	(11,101)	(1,761)
Unrealized gain on available-for-sale instrument, net of tax	—	451
	$(10,738)	$ (316)

Stock Awards

Under the Company's 2000 Stock Incentive Plan, shares of common stock may be granted to key employees under terms and conditions determined by management. These stock grants generally vest over a period of four to six years and are distributed to the employees as the shares vest. The Company determines employee compensation based on the market price of its common stock on the date of grant. Unearned compensation arising from the stock grants is shown as a reduction in stockholders' equity in the consolidated balance sheets and is amortized using the straight-line method as additional compensation expense over the vesting period.

Stock Options

The Company applies APB Opinion 25, "Accounting for Stock Issued to Employees," and related interpretations in accounting for all stock option plans. No stock-based compensation cost has been recognized in the consolidated statements of operations for stock options granted to employees because the option exercise price was equal to or exceeded the market price of the underlying common stock on the date of grant.

SFAS No. 123, "Accounting for Stock-Based Compensation," requires the Company to provide pro forma information regarding net income (loss) as if the compensation cost for the Company's stock option plans had been determined in accordance with the fair value based method prescribed in SFAS No. 123. To provide the required pro forma information, the Company estimates the fair value of each stock option at the grant date by using the Black-Scholes option-pricing model. The following table represents the pro forma effect on net income (loss) and income (loss) per share as if the Company

(1) SUMMARY OF ACCOUNTING POLICIES (Continued)

had applied the fair value based method and recognition provisions of SFAS No. 123 to stock-based employee compensation:

	Years Ended December 31,		
	2003	2002	2001
	(in thousands, except per share data)		
Net income (loss) attributable to common stockholders, as reported	$72,628	$(8,324)	$38,527
Add: Stock-based employee compensation included in reported net income (loss), net of tax	924	130	220
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of tax	(2,750)	(1,428)	(2,957)
Pro forma net income (loss)	$70,802	$(9,622)	$35,790
Income (loss) per share:			
Basic income (loss) per common share:			
As reported	$ 1.84	$ (0.22)	$ 1.04
Pro forma	$ 1.79	$ (0.25)	$ 0.97
Diluted income (loss) per common share:			
As reported	$ 1.77	$ (0.22)	$ 0.99
Pro forma	$ 1.72	$ (0.25)	$ 0.92

See Notes 9 and 10 for further discussion of the Company's stock-based employee compensation.

Foreign Currency Translation

The functional currency for the Company's foreign operations is the applicable foreign currency. The translation of the applicable foreign currency into U.S. dollars is performed for balance sheet accounts using current exchange rates in effect at the balance sheet date and for revenue and expense accounts using a weighted average exchange rate during the period. The gains or losses resulting from such translation are generally included in the consolidated statements of stockholders' equity and comprehensive income (loss).

In each the years ended December 31, 2003 and 2002, the Company recognized a $1.0 million foreign currency gain in its consolidated statement of operations which was previously recorded in the consolidated statements of stockholders' equity as accumulated other comprehensive income (loss). The recognition of these gains was associated with the Company's exit of its United Kingdom, Northern Ireland and Republic of Ireland operations. See Note 4 for further information.

(1) SUMMARY OF ACCOUNTING POLICIES (Continued)

Financial Instruments

The following table presents the carrying amounts and estimated fair values of certain of the Company's financial instruments:

	December 31,			
	2003		2002	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(in thousands)			
Investment in common stock in unaffiliated company	$ —	$ —	$ 2,186	$ 2,186
Derivative instruments	(17,482)	(17,482)	(2,733)	(2,733)
Notes payable	(149,373)	(149,373)	(136,000)	(136,000)
Senior convertible notes	(100,000)	(143,625)	(100,000)	(115,625)

The following methods and assumptions were used to estimate the fair value of the financial instruments summarized in the table above. The carrying values of cash, accounts receivable, other assets, payables, accrued liabilities and asset retirement obligations approximate their fair values at December 31, 2003 and 2002 either due to their short term nature of the instrument or rates used to measure the instrument are reflective of current market rates.

Investment in common stock of unaffiliated company: The fair value of the investment in the common stock of an unaffiliated company, which was liquidated during 2003, was based on the quoted market price of such common stock at December 31, 2002. The Company's investment in an unaffiliated company was classified as available-for-sale. Available-for-sale securities are carried at fair value, with the unrealized gains and losses reported in the consolidated statements of stockholders' equity as accumulated other comprehensive income (loss).

Derivative Instruments: The fair values of the costless collar contracts were calculated using the Black-Scholes option-pricing model which factors in such variables as the term of the derivative contracts, the volatility of the gas market and the current risk-free rates of return on similar-termed investments. The values of the natural gas swaps were determined using expected discounted future cash flows. See "Hedging Activities" for more information.

Debt: The carrying amount of notes payable approximated fair value because the interest rates on the notes payable are variable. The fair value of the senior convertible notes was based on the quoted market prices of the convertible debt.

The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of cash equivalents and accounts receivable. The Company's cash equivalents are cash investment funds which are placed with a major financial institution. The Company manages and controls market and credit risk through established formal internal control procedures, which are reviewed on an ongoing basis. The Company attempts to minimize credit risk exposure to purchasers of the Company's oil and natural gas through formal credit policies, monitoring procedures and letters of credit. See Note 11 for concentrations of accounts receivable at December 31, 2003.

(1) SUMMARY OF ACCOUNTING POLICIES (Continued)

Hedging Activities

Derivative financial instruments, utilized to manage or reduce commodity price risk related to the Company's production, are accounted for under the provisions of SFAS No. 133, "Accounting for Derivative Instruments and for Hedging Activities", and related interpretations. Under this statement, all derivatives are carried on the balance sheet at fair value. If the derivative is designated as a fair value hedge, the changes in the fair value of the derivative and of the hedged item attributable to the hedged risk are recognized in earnings. If the derivative is designated as a cash flow hedge, the effective portions of changes in the fair value of the derivative are recorded in other comprehensive income ("OCI") and are recognized in the statement of operations when the hedged item affects earnings. If the derivative is not designated as a hedge, changes in the fair value are recognized in the statement of operations. Ineffective portions of changes in the fair value of cash flow hedges are recognized in earnings. The adoption of SFAS No. 133 in January 2001 resulted in an after-tax reduction to OCI of approximately $0.4 million as a cumulative effect of change in accounting principle.

The Company may use derivative instruments to manage exposures to commodity prices, foreign currency and interest rate risks. The Company's objectives for holding derivatives are to achieve a consistent level of cash flow to support its capital budgeting and expenditure plans and to maximize internal rates of return for capital projects including property acquisition investments.

The Company periodically enters into fixed-price physical delivery contracts and commodity derivative contracts to manage price risk with regard to a portion of its natural gas production. The table below summarizes the open derivative contracts the Company had in place as of December 31, 2003 by contract period. ("MMBtu" means million British thermal units and convert on an approximate one-for-one basis into Mcf.) The weighted average prices of the commodity contacts have been adjusted for anticipated fuel use and regional price differentials.

Contract Period	Market	Volume in MMBtu/ day	Weighted Average $/MMBtu	Unrealized Losses at December 31, 2003 (in thousands)
Jan 04—Oct 04	Midcontinent	65,000	$4.86	$ 2,044
Jan 04—Dec 04	Midcontinent	50,000	4.20	14,065
Jan 04—Dec 04	Northwest Pipeline—Rockies	3,000	4.33	786
Jan 04—Dec 04	AECO—Canada	4,739	4.63	587
				$17,482

As of December 31, 2003, the Company had recorded net unrealized losses of $17.5 million related to its derivative instruments, which represented the estimated aggregate fair values of the Company's open derivative contracts as of that date. These unrealized losses are presented on the Consolidated Balance Sheet as a current liability of $17.8 million and a current asset of $0.3 million. Based on the calculated fair values at December 31, 2003, the Company expects to reclassify net losses of $17.5 million into earnings related to the derivative contracts during the next 12 months. Actual gains or losses recognized may be materially different than what was estimated at December 31, 2003 and

(1) SUMMARY OF ACCOUNTING POLICIES (Continued)

will depend solely on the regional price indices of the commodities on the specified settlement dates provided by the derivative contracts.

The Company's commodity derivative contracts are generally designated as cash flow hedges. To qualify as a cash flow hedge, these derivative contracts must be designated as cash flow hedges and changes in their fair value must correlate with changes in the price of anticipated future production such that the Company's exposure to the effects of commodity price changes is reduced. When cash flow hedge accounting is applied, the effective portion of changes in the fair values of the derivative instrument is recorded in other comprehensive income. No hedge ineffectiveness was recognized during the years ended December 31, 2003, 2002 and 2001. For the years ended December 31, 2003, 2002 and 2001, the Company recognized $11.8 million of net losses, $6.5 million of net losses and $13.9 million of net gains related to its natural gas hedging activities, respectively. These losses and gains are included in oil and natural gas revenues in the Consolidated Statements of Operations and are included in cash flows from operations in the Consolidated Statements of Cash Flows.

During 2003, the Company entered into various derivative instruments in order to hedge several forecasted transactions associated with the anticipated acquisition of Carbon that did not qualify for hedge accounting. In connection therewith, the Company recognized approximately $1.2 million of losses during 2003 which are included in other expenses in the Consolidated Statements of Operations and are included in cash flows used in investing activities in the Consolidated Statements of Cash Flows.

The Company also had an interest rate swap in place from April 2001 through April 2002 having a notional amount of $25 million at a LIBO rate of 4.4%. The Company recognized losses of $0.2 million during each of the years ended December 31, 2002 and 2001 related to this interest rate swap.

The Company is exposed to credit risk in the event of nonperformance by the counterparties in the derivative contracts discussed above; however, the Company does not anticipate nonperformance by the counterparties.

Subsequent to December 31, 2003, the Company entered into the following commodity swap agreement:

Contract Period	Market	Volume in MMBtu/ day	Net Price per MMBtu
Feb 04—Mar 04	Midcontinent	10,000	$6.35

Reclassifications

Certain items included in prior years' consolidated financial statements have been reclassified to conform to current year presentation.

Recent Accounting Pronouncements

In June 2001, the FASB issued SFAS No. 141, "Business Combinations" and SFAS No. 142, "Goodwill and Other Intangible Assets." SFAS No. 141 addresses accounting and reporting for business combinations and is effective for all business combinations initiated after June 30, 2001. SFAS No. 142

(1) SUMMARY OF ACCOUNTING POLICIES (Continued)

addresses the accounting and reporting for goodwill subsequent to acquisition and other intangible assets. The new standard eliminates the requirement to amortize acquired goodwill; instead, such goodwill is required to be reviewed at least annually for impairment. The new standard also requires that, at a minimum, all intangible assets be aggregated and presented as a separate line item in the balance sheet. The adoption of SFAS No. 141 and SFAS No. 142 had no impact on Evergreen's financial position or results of operations.

A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141 and SFAS No. 142 to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights held under lease or other contractual arrangement associated with extracting oil and gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, Evergreen has included the costs of such mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights held under lease or other contractual arrangement associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, Evergreen would be required to reclassify approximately $189 million at December 31, 2003 and $6.5 million at December 31, 2002 out of oil and gas properties and into a separate intangible assets line item. Evergreen's cash flows and results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with full-cost accounting rules.

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires the fair value of a liability for an asset retirement obligation to be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. SFAS No. 143 was effective for the Company on January 1, 2003. See Note 5 for discussion of the impact on the Company's consolidated financial statements.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB No. 4, 44 and 64, Amendment of FASB No. 13, and Technical Corrections." SFAS No. 145 rescinds FASB No. 4 "Reporting Gains and Losses from Extinguishments of Debt Made to Satisfy Sinking-Fund Requirements." This statement also rescinds SFAS No. 44, "Accounting for Intangible Assets of Motor Carriers" and amends SFAS No. 13, "Accounting for Leases." This statement also amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. The Company adopted this statement on January 1, 2003. The adoption of this statement did not have a material effect on the Company's financial statements.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." SFAS No. 146 addresses accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (Including Certain Costs Incurred in a Restructuring)." SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized and measured initially at fair value when the liability is incurred. SFAS No. 146 was effective for exit or disposal activities that are initiated after December 31, 2002. The adoption of this statement did not have a material effect on the Company's financial statements.

(1) SUMMARY OF ACCOUNTING POLICIES (Continued)

During December 2003, the FASB issued Interpretation No. 46R, "Consolidation of Variable Interest Entities" ("FIN 46"), which requires the consolidation of certain entities that are determined to be variable interest entities ("VIE's"). An entity is considered to be a VIE when either (i) the entity lacks sufficient equity to carry on its principal operations, (ii) the equity owners of the entity cannot make decisions about the entity's activities or (iii) the entity's equity neither absorbs losses or benefits from gains. Evergreen owns no interests in variable interest entities, and therefore this new interpretation has not affected the Company's consolidated financial statements.

In May 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS No. 149 amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 149 is generally effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. The adoption of this statement did not have a material effect on the Company's financial statements.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity." SFAS No. 150 establishes standards for how an issuer measures certain financial instruments with characteristics of both liabilities and equity and requires that an issuer classify a financial instrument within its scope as a liability (or asset in some circumstances). SFAS No. 150 was effective for financial instruments entered into or modified after May 31, 2003 and otherwise was effective and adopted by the Company on July 1, 2003. As the Company has no such instruments, the adoption of this statement did not have an impact on the Company's financial condition or results of operations.

(2) ACCOUNTS RECEIVABLE

The components of accounts receivable include the following:

	December 31,	
	2003	2002
	(in thousands)	
Oil and natural gas sales	$23,982	$15,949
Joint interest billings and other	1,689	1,732
Employees	37	3
	$25,708	$17,684

(3) ACQUISITIONS AND DIVESTITURES

Carbon Energy Corporation

Evergreen completed the acquisition of Carbon on October 29, 2003. Carbon was an independent oil and gas company engaged in the exploration, development and production of oil and natural gas in the United States and Canada. Carbon's areas of operations in the United States were in the Piceance Basin in Colorado and the Uintah Basin in Utah. Carbon's area of operations in Canada was the Western Canada Sedimentary Basin. The reasons for the Carbon acquisition were numerous, including,

(3) ACQUISITIONS AND DIVESTITURES (Continued)

but not limited to the potential for increased production, reserves and undeveloped acreage as well as diversification in terms of both current production and long-term growth opportunities.

The acquired Carbon properties were estimated by independent petroleum engineering consultants to contain at least 97 billion cubic feet equivalent ("Bcfe") of estimated proved reserves, substantially all of which are natural gas. Carbon operated substantially all of its properties in the United States and Canada. At the time of acquisition, net oil and gas reserves in the United States and Canada were estimated at approximately 59 Bcfe and 38 Bcfe, respectively, of which 45% and 73% were classified as proved developed and the remaining amounts were classified as proved undeveloped. Average daily net production in the United States and Canada from the acquired properties during the month of December 31, 2003 was 13.4 million cubic feet of gas equivalent. The gross acreage position acquired was approximately 150,000 acres in the United States and 130,000 acres in Canada.

Under the terms of the acquisition agreement, Carbon's shareholders received 0.55 shares of Evergreen common stock for each common share of Carbon in exchange for all the outstanding common shares of Carbon. As a result, Evergreen issued approximately 3.5 million new shares of Evergreen common stock to Carbon's shareholders. The aggregate value of the transaction, including the value of the common stock issued, transaction costs, change in control payments and the fair value of Carbon employee stock options assumed by Evergreen was approximately $88.4 million. The shares of common stock issued to Carbon shareholders were valued at $22.72 per share which was the average value of the Company's common stock for several days before and after the agreement was announced. The fair value of the outstanding Carbon stock options were valued using the Black Scholes option pricing model. The total purchase price of $88.4 million was allocated to the assets acquired and the liabilities assumed based on the estimated fair values as set forth in the table below. The purchase price allocation is preliminary and will be finalized after management's final review of the relative fair values of the net assets acquired.

	Purchase Price Allocation
	(in thousands)
Working capital	$ (3,048)
Oil and gas properties—proved	135,454
Oil and gas properties—unproved	9,399
Gathering assets and support equipment	5,136
Deferred income taxes	(33,359)
Notes payable	(19,757)
Asset retirement obligation	(5,467)
Total purchase price	$ 88,358

(3) ACQUISITIONS AND DIVESTITURES (Continued)

The purchase price of $88.4 million consisted of the following:

	Purchase Price Components
	(in thousands)
Fair value of common stock issued	$78,720
Fair value of Carbon stock options assumed by Evergreen	3,487
Acquisition costs	6,151
Total purchase price	$88,358

In connection with the Carbon acquisition, the Company recorded a deferred income tax liability of $33.4 million to recognize the difference between the historical tax basis of Carbon and the net acquisition cost recorded for book purposes.

The results of Carbon's operations were included in the consolidated operations from the date of the acquisition. The following table reflects unaudited pro forma results of operations for the twelve months ended December 31, 2003 and 2002 as though the Carbon acquisition had occurred on January 1 of each year presented. The pro forma results are not necessarily indicative of the results that would have been obtained had the acquisition occurred as of an earlier date or results which may be reported in the future.

	Years Ended December 31,	
	2003	2002
	(in thousands, except per share amounts)	
Net revenue	$234,203	$125,734
Net income (loss) before cumulative effect of change in accounting principle	72,498	(26,878)
Net income (loss)	72,121	(26,878)
Income (loss) per common share before cumulative effect of change in accounting principle:		
Basic	$ 1.71	$ (0.65)
Diluted	$ 1.64	$ (0.65)
Income (loss) per common share:		
Basic	$ 1.70	$ (0.65)
Diluted	$ 1.63	$ (0.65)

The pro forma results of operations above do not give effect to the direct operating revenues and expenses of certain producing properties sold by Carbon during 2003 prior to Evergreen's acquisition.

(3) ACQUISITIONS AND DIVESTITURES (Continued)

Other

In December 2003, the Company acquired an additional 41,000 gross acres of prospective and producing properties in Utah for approximately $5.9 million in cash. The acreage currently has 18 producing wells with an estimated 6.9 Bcf of reserves.

On March 26, 2003, Evergreen entered into a settlement agreement with certain working interest owners in the Raton Basin, under which Evergreen agreed to sell certain mineral interests held by the Company and an approximate 25% membership interest in Long Canyon Gas Company, LLC for $3.75 million. On April 16, 2003, the transaction closed with an effective date of January 1, 2003. Net revenues of approximately $0.7 million from the effective date through the closing date were recorded as a sales price adjustment.

(4) PROPERTY AND EQUIPMENT

Property and equipment include the following:

	December 31,	
	2003	2002
	(in thousands)	
Oil and gas properties:		
Proved oil and gas properties	$649,697	$438,293
Unproved properties not subject to amortization	85,841	29,163
Accumulated depletion	(74,671)	(54,061)
Net oil and gas properties	660,867	413,395
Other:		
Gas collection system	199,359	157,740
Construction in progress	3,393	4,097
Support equipment	27,467	25,554
Accumulated depreciation and amortization	(28,448)	(20,370)
Net other property and equipment	201,771	167,021
Property and equipment, net of accumulated depreciation, depletion and amortization	$862,638	$580,416

Included in construction in progress at December 31, 2003 are costs associated with compressor facilities and inventories. Oil and gas property costs of $85.8 million and $29.2 million were not being amortized at December 31, 2003 and December 31, 2002. The Company's unproved properties consist of domestic properties and Canadian properties. The Company expects to classify the unproved costs as proved costs over the next three to five years when future development of the properties determines the viability of the underlying reserves.

In 2002, the Company impaired approximately $51.5 million of international oil and gas properties net of a foreign currency effect of approximately $1.0 million, which was related to the operation in Northern Ireland and the Republic of Ireland. Of this amount, approximately $33.1 million related to a

(4) PROPERTY AND EQUIPMENT (Continued)

coal bed methane project in the United Kingdom, $13.7 million related to wells drilled in Northern Ireland and the Republic of Ireland and $4.7 million related to undeveloped acreage held in the Falkland Islands and Chile. During 2003, the Company completed its plugging and abandonment obligations in the United Kingdom and Ireland for a total cost of approximately $1.7 million, net of a foreign currency effect of $1.0 million.

The Company is a vertically integrated oil and gas producer, meaning that a significant portion of the Company's fracture stimulation and pipeline construction is performed by certain of its wholly owned subsidiaries. During the years ended December 31, 2003, 2002 and 2001, the Company capitalized to oil and gas properties $6.6 million, $4.5 million and $2.6 million, respectively, of salary-related costs incurred by its subsidiaries in performing these functions.

(5) ASSET RETIREMENT OBLIGATION

Effective January 1, 2003, the Company adopted the provisions of SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires the fair value of a liability for an asset retirement obligation to be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the related oil and gas properties and gas collection systems. The adoption of this statement required the Company to record a non-cash expense, net of tax, of approximately $0.7 million as a cumulative effect of change in accounting principle in the first quarter of 2003, as well as a non-current liability of approximately $4.6 million and an addition to oil and gas properties and the gas collection system of approximately $3.9 million.

The schedule below is a reconciliation of the Company's liability for year ended December 31, 2003:

	Asset Retirement Obligation
	(in thousands)
Upon adoption at January 1, 2003	$ 4,631
Acquisitions	5,467
Liabilities incurred	1,141
Liabilities settled	(7)
Accretion	465
Revisions to estimate	1,146
Foreign currency exchange rate effect	33
Liability at December 31, 2003	$12,876

(5) ASSET RETIREMENT OBLIGATION (Continued)

The schedule below reflects, on a pro forma basis, the net (loss) income, net (loss) income per share amounts as if the provisions of SFAS No. 143 had been applied during all the periods presented.

	Years Ended December 31,		
	2003	2002	2001
Net income (loss), as reported	$72,628	$(8,324)	$38,527
Pro forma adjustments, net of tax	713	(251)	(187)
Pro forma net income (loss)	$73,341	$(8,575)	$38,340
Basic net income (loss) per share, as reported	$ 1.84	$ (0.22)	$ 1.04
Basic net income (loss) per share, pro forma	$ 1.86	$ (0.23)	$ 1.03
Diluted net income (loss) per share, as reported	$ 1.77	$ (0.22)	$ 0.99
Diluted net income (loss) per share, pro forma	$ 1.79	$ (0.23)	$ 0.99

(6) NOTES PAYABLE

The Company currently has a $200 million revolving credit facility with a bank group. The credit facility is available through July 1, 2005. Advances pursuant to this credit facility are limited to a borrowing base, as defined by the credit facility, which was $200 million at December 31, 2003. The Company may elect to use either the LIBO rate plus a margin of 1.125% to 1.50% or the prime rate plus a margin of 0% to 0.25%, with margins on both rates determined on the average outstanding borrowings under the credit facility. The borrowing base is redetermined semi-annually by the bank group based upon reserve evaluations of Evergreen's oil and gas properties. An annual commitment fee of 0.375% is charged quarterly for any unused portion of the credit line. The agreement is collateralized by substantially all domestic oil and gas properties and guaranteed by substantially all of the Company's subsidiaries. The credit agreement also contains certain net worth, leverage and ratio requirements and limits the payment of dividends. At December 31, 2003, Evergreen had $135.5 million of outstanding borrowings under this credit facility, with a current average interest rate of approximately 2.6%. The Company was in compliance with all loan covenants at December 31, 2003.

In connection with the purchase of Carbon, the Company assumed a credit facility with Canadian Imperial Bank of Commerce ("CIBC"). At December 31, 2003 outstanding borrowings were $13.9 million. This facility is secured by the Canadian oil and gas properties of the Company. The revolving phase of the Canadian facility expires on March 31, 2004. The facility with CIBC bears interest at a rate equal to banker's acceptance rates plus 1.25% or at the CIBC Prime rate plus 0.5%. The Company's current average interest rate on this credit facility was 5.0% at December 31, 2003. The CIBC credit facility contains various covenants with which the Company was in compliance at December 31, 2003. The agreement with CIBC also provides for $5.0 million of credit which can be utilized for financial derivative instruments used to hedge a portion of the Company's oil and gas production, currency exchange contracts and fixed price gas sales transactions with CIBC. No such credit was being utilized as of December 31, 2003. Should the Company be unable to extend the term of the CIBC credit facility, it has the ability and intent to repay amounts owed on the facility with

(6) NOTES PAYABLE (Continued)

advances on its $200 million revolving credit facility described above. Accordingly, the Company has classified the amounts due under the CIBC credit facility as non-current at December 31, 2003.

(7) SENIOR CONVERTIBLE NOTES

In December 2001, the Company issued $100 million in senior unsecured convertible notes. The notes are due in 2021 and bear interest at a fixed annual rate of 4.75%, which is to be paid in cash on June 15 and December 15 of each year. In addition to the fixed interest, the Company is required to pay contingent interest to the holders of the notes if the average trading price of the notes for an established number of days exceeds 120% or more of the principal amount of the notes. The rate of contingent interest payable in respect to any six-month period will equal the greater of (1) a per annum rate equal to 5% of the Company's estimated per annum borrowing rate for senior non-convertible fixed-rate debt with a maturity date comparable to the notes or (2) 0.30% per annum. In no event may the contingent interest rate exceed 0.40% per annum. The Company paid contingent interest of $0.2 million on the notes during 2003 and will be required to pay an additional $0.2 million in contingent interest on June 15, 2004.

The notes are general unsecured obligations, ranking on a parity in right of payment with all of Evergreen's existing and future senior indebtedness, and senior in right of payment with all of Evergreen's future subordinated indebtedness. The notes are due on December 15, 2021 but are redeemable at either the Company's option or the holder's option on other specified dates. The Company may redeem the notes at its option in whole or in part beginning on December 20, 2006, at 100% of their principal amount plus accrued and unpaid interest (including contingent interest). Holders of the notes may require the Company to repurchase the notes if a change in control of the Company occurs. Holders may also require the Company to repurchase all or part of the notes on December 20, 2006, December 15, 2011 and December 15, 2016 at a repurchase price of 100% of the principal amount of the notes plus accrued and unpaid interest (including contingent interest). On December 20, 2006, the Company may pay the repurchase price in cash, in shares of common stock, or in any combination of cash and common stock. On December 15, 2011 and December 15, 2016, the Company must pay the repurchase price in cash.

The notes are convertible into shares of common stock of Evergreen under certain circumstances as discussed below at a conversion price of $25 per share, subject to certain adjustments. The notes can be converted at the option of the holder if for a specified period of time, the closing price of the Company's common stock exceeds 110% of the $25 conversion price, which occurred in November 2003, or if the average trading value of the notes for a specified period of time is less than 105% of an average conversion value as defined by the indenture governing the notes. Given that the notes are eligible for conversion, they are currently considered potential common shares in the computation of fully diluted shares. The notes may also be converted into shares of common stock of the Company at the election of the holder upon notice of redemption, or at any time the notes are rated by either Moody's Investors Service, Inc. or Standard & Poor's Rating Group and the credit rating initially assigned to the notes by either such rating agency is reduced by two or more ratings levels, or upon the occurrence of certain corporate transactions including a change in control or the distribution to current holders of the Company's common stock certain purchase rights or any other

(7) SENIOR CONVERTIBLE NOTES (Continued)

asset that has a value exceeding 10% of the sale price of the common stock on the day preceding the declaration date of the distribution of such assets.

(8) INCOME TAXES

The provision for income taxes consists of the following:

	Years Ended December 31,		
	2003	2002	2001
	(in thousands)		
Current—Foreign	$ 221	$ —	$ —
Deferred:			
Federal	39,948	(4,517)	21,478
Foreign	(85)	—	—
State, net	1,684	(65)	1,360
Total deferred	41,547	(4,582)	22,838
Total income tax provision	$41,768	$(4,582)	$22,838

The Company's income tax provision is attributable to the following items:

	Years Ended December 31,		
	2003	2002	2001
Income tax provision	$42,178	$(4,582)	$22,838
Income tax provision for cumulative change in accounting principle	(410)	—	—
Total income tax provision	$41,768	$(4,582)	$22,838

The deferred income tax provision shown above excludes amounts related to the tax benefit of stock options exercised in 2003, 2002 and 2001 for which the benefit was credited directly to stockholders' equity.

A reconciliation of income tax computed at the federal and state statutory tax rates and the Company's effective tax rate is as follows:

	Years Ended December 31,		
	2003	2002	2001
Federal income tax provision at statutory rate	35.0%	(35.0)%	35.0%
State income tax provision at statutory rate, net of federal income tax effect	3.1	(3.0)	3.0
Rate differential of foreign operations	—	—	—
State tax credits, net of valuation allowance and other	(1.6)	2.5	(0.8)
Total income tax provision	36.5%	(35.5)%	37.2%

(8) INCOME TAXES (Continued)

The components of the net deferred tax liability at December 31, 2003 and 2002 are shown below:

	December 31, 2003		
	United States	Canada	Total
		(in thousands)	
Net operating loss carryforwards	$ 46,269	$ —	$ 46,269
Percentage depletion carryforwards	1,329	—	1,329
Tax credits, net of valuation allowance of $4,512	4,261	—	4,261
Asset retirement obligation	3,964	1,015	4,979
Unrealized losses on derivative instruments	6,381	—	6,381
Other	2,797	—	2,797
Total deferred tax assets, net	65,001	1,015	66,016
Net property and equipment	(131,651)	(23,160)	(154,811)
Original issue discount—senior convertible notes	(3,549)	—	(3,549)
Other	(11)	—	(11)
Total deferred tax liabilities	(135,211)	(23,160)	(158,371)
Net deferred tax liability	$ (70,210)	$(22,145)	$ (92,355)

	December 31, 2002		
	United States	Canada	Total
		(in thousands)	
Net operating loss carryforwards	$ 25,383	$ —	$ 25,383
Percentage depletion carryforwards	1,328	—	1,328
Tax credits, net of valuation allowance of $5,264	2,055	—	2,055
Other	1,731	—	1,731
Total deferred tax assets, net	30,497	—	30,497
Net property and equipment	(56,143)	—	(56,143)
Original issue discount—senior convertible notes	(1,733)	—	(1,733)
Other	(287)	—	(287)
Total deferred tax liabilities	(58,163)	—	(58,163)
Net deferred tax liability	$ (27,666)	$ —	$ (27,666)

As of December 31, 2003, the Company had net operating loss carryforwards for tax purposes of approximately $121.6 million, which expire beginning in 2009 through 2023. Additionally, the Company had tax credit carryforwards for tax purposes of approximately $8.8 million of which $8.6 million relate to state credits that will expire beginning in 2003 through 2015.

Due to the Company's acquisition of Carbon, approximately $14.7 million of the U.S. net operating loss carryforwards reported above is subject to limitation under Section 382 of the Internal Revenue Code. The annual limitation of this net operating loss is approximately $2.1 million.

(8) INCOME TAXES (Continued)

The state tax credits are subject to limitation, and the Company has concluded that, based upon expected future results, the future reversal of taxable temporary differences and the tax benefits derived from the exercise of stock options, there is no reasonable assurance that the entire benefit of the tax credits can be used. Accordingly, a valuation allowance has been established.

Included in deferred income taxes payable at December 31, 2003 and 2002, are the tax effects of unrealized gains on the Company's available for sale investments of $0.0 million and $0.3 million and unrealized losses on derivative instruments of $6.4 million and $1.0 million.

(9) STOCKHOLDERS' EQUITY

Earnings (Loss) per Share

The following table sets forth the computation of basic and diluted earnings (loss) per share:

	Years Ended December 31,		
	2003	2002	2001
	(in thousands, except per share data)		
Numerator:			
Net income (loss) and numerator for basic earnings (loss) per share	$72,628	$(8,324)	$38,527
Interest on senior convertible notes, net of tax	445	—	—
Numerator for dilutive earnings (loss) per share	$73,073	$(8,324)	$38,527
Denominator:			
Denominator for basic earnings (loss) per share—weighted average shares	39,446	37,912	37,067
Effect of dilutive securities:			
Stock options and unvested restricted stock grants	1,318	—	1,754
Assumed conversion of senior convertible notes	548	—	—
Dilutive potential common shares	1,866	—	1,754
Denominator for diluted earnings (loss) per share	41,312	37,912	38,821

For the year ended December 31, 2002, options to purchase 2,810,056 shares of common stock were excluded from the computation of diluted earnings (loss) per share as their inclusion would have had an antidilutive effect. For the years ended December 31, 2003 and 2001, all potential common shares were included in the computation of diluted earnings per share. As discussed in Note 7, the Company issued $100 million in senior unsecured convertible notes in December 2001 that are convertible into shares of common stock under certain circumstances. During the fourth quarter of 2003, the Company's $100 million senior unsecured convertible notes became convertible into four million shares of Evergreen common stock at $25 per share due to the average market price of the Company's common stock surpassing certain levels for a certain period of time as prescribed by the indenture agreement. As such, these notes were considered convertible for a period of fifty days during the fourth quarter of 2003. At December 31, 2002 and 2001, no potential common shares were included

(9) STOCKHOLDERS' EQUITY (Continued)

in the computation of diluted earnings (loss) per share related to these senior unsecured convertible notes as no circumstances had occurred during those periods that would allow the notes to be converted into Evergreen common stock.

Stock Issued for Services

During the years ended December 31, 2002 and 2001, the Company issued common stock valued at $0.5 million and $0.9 million as compensation to employees, directors and consultants. During 2003 and 2002, the Company granted 304,800 and 73,000 shares of common stock, respectively, to certain employees that vest over four to six years. These shares were valued at approximately $7.0 million and $1.4 million at the grant dates, respectively, (representing a weighted average fair value of $23.00 and $18.66 per share, respectively) and recorded as deferred compensation in stockholders' equity. The Company amortized deferred compensation of $1.7 million and $0.2 million during the years ended December 31, 2003 and 2002 related to these stock grants.

Stock Issued for Property Interests

During the year ended December 31, 2001, the Company issued 79,380 shares of stock for property interests and right of ways valued at $1.2 million, which included 46,400 shares valued at $0.8 million as partial consideration for a 100% working interest in 1,085,000 acres in Northern Ireland and the Republic of Ireland.

As discussed in Note 3, the Company acquired Carbon during 2003 in exchange for approximately 3.5 million shares of Evergreen common stock valued at approximately $78.7 million as part of the purchase consideration. The Company also acquired certain property interests in Kansas during 2003 in exchange for approximately 0.5 million shares of common stock valued at approximately $12.4 million.

Shareholder Rights Plan

On July 7, 1997, the Board of Directors adopted a Shareholder Rights Plan ("Rights Plan"), pursuant to which stock purchase rights (the "Rights") were distributed as a dividend to the Company's common stockholders at a rate of one Right for each share of common stock held of record as of July 22, 1997 and for each share of stock issued thereafter. The Rights Plan is designed to enhance the Board's ability to prevent an acquirer from depriving stockholders of the long-term value of their investment and to protect shareholders against attempts to acquire the Company by means of unfair or abusive takeover tactics that have been prevalent in many unsolicited takeover attempts.

(9) STOCKHOLDERS' EQUITY (Continued)

Under the Rights Plan, the Rights will become exercisable only if a person or a group (except for 20% shareholders existing at the time the Rights Plan was adopted) acquires or commences a tender offer for 20% or more of the Company's common stock. Until they become exercisable, the Rights attach to and trade with the Company's common stock. The Rights will expire July 22, 2007. The Rights may be redeemed by the continuing members of the Board at $0.001 per Right prior to the day after a person or group has accumulated 20% or more of the Company's common stock.

Stock Split

All common stock and per-share amounts reported in the consolidated financial statements, and notes thereto, reflect the two-for-one split of Evergreen common stock which was effective as of September 16, 2003.

Increase of Authorized Shares of Common Stock

On November 25, 2003, the Company filed Articles of Amendment to its Amended and Restated Articles of Incorporation with the Department of State of the State of Colorado to increase the number of authorized shares of Evergreen common stock from 50 million shares to 100 million shares. The amendment was duly approved by both Evergreen's Board of Directors and shareholders.

(10) STOCK OPTIONS

On May 12, 1997, the Board of Directors adopted, and the Company's shareholders subsequently approved, an Initial Stock Option Plan (the "Plan"), whereby employees may be granted incentive options to purchase up to 1,000,000 shares of the common stock of the Company. The exercise price of incentive options must be equal to at least the fair market value of the common stock as of the date of grant. As of December 31, 2003, the Company had granted 1,000,000 options available under the Plan.

Under the terms of the Company's Key Employee Equity Plan, the exercise price of options and/or warrants granted to key employees were not less than the market price of the Company's common stock on the date of grant. The purpose of the warrants are to reward directors and key personnel for past performance and to give them an incentive to remain with the Company and to induce directors to take all or part of their compensation in the form of common stock.

On June 16, 2000, the Company's stockholders approved the 2000 Stock Incentive Plan (the "2000 Plan"). Under the 2000 Plan, the Company may grant options to purchase up to 2,000,000 shares of its common stock, plus an annual increase equal to the lesser of either 300,000 shares or an amount determined by the Board of Directors. The Board of Directors approved increases of 300,000 shares for each of 2003, 2002 and 2001. Awards which may be granted under the 2000 Plan include incentive stock options, non-qualified stock options, stock appreciation rights, restricted stock awards and restricted units. As of December 31, 2003, the Company had granted approximately 1,069,000 awards under the 2000 Plan and had approximately 1,129,000 shares available to be issued under the Plan and the 2000 Plan.

In connection with the Carbon acquisition, options previously issued by Carbon were exchanged for options to purchase 224,218 shares of Evergreen common stock at exercise prices between $7.61 and $18.42 per share.

(10) STOCK OPTIONS (Continued)

During the year ended December 31, 2003, options to purchase 171,606 shares of common stock were granted to the directors of the Company at a weighted average purchase price of $22.75. During the year ended December 31, 2002, the Company granted options to purchase 5,000 shares to an employee at an exercise price of $19.06. During the year ended December 31, 2001, the Company granted options to purchase 924,600 shares to its directors, officers and employees at exercise prices ranging from $14.75 to $18.00.

	Years Ended December 31,					
	2003		2002		2001	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding,						
Beginning of period	2,810,056	$11.22	3,342,228	$11.05	3,457,872	$ 7.58
Granted	395,824	18.67	5,000	19.06	924,600	16.6
Exercised	(827,702)	8.99	(415,072)	8.93	(1,006,744)	4.25
Forfeitures	(62,750)	15.49	(122,100)	14.75	(33,500)	12.18
Outstanding, End of period	2,315,428	$12.81	2,810,056	$11.22	3,342,228	$11.05
Options and warrants exercisable, end of period	1,401,428	$10.78	1,507,806	$ 8.92	1,238,852	$ 7.26
Weighted average per-share fair value of options and warrants granted during the period		$14.59		$11.20		$11.20

Pro forma information regarding net income (loss) and net income (loss) per share, as disclosed in Note 1, has been determined as if the Company had accounted for its employee stock-based compensation plans and other stock options under the fair value method of SFAS No. 123. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used for grants under the fixed option plans:

	Years Ended December 31,		
	2003	2002	2001
Risk-free interest rate	3.05% - 4.07%	3.92%	4.29% - 5.10%
Expected life of option in years	5 - 10	10	5 - 10
Expected stock volatility	37% - 41%	42%	51%
Expected dividend yield	0%	0%	0%

(10) STOCK OPTIONS (Continued)

The following table summarizes information about stock options and warrants outstanding at December 31, 2003:

	Outstanding			Exercisable	
Range of Exercise Prices	Number Outstanding at December 31, 2003	Weighted Average Remaining Contractual Life in Years	Weighted Average Exercise Price	Number Exercisable at December 31, 2003	Weighted Average Exercise Price
$ 3.50–$ 9.25	994,422	6.32	$ 7.99	813,172	$ 7.61
$13.69–$13.72	507,350	6.86	13.70	348,850	13.70
$14.75–$27.15	813,656	8.06	18.15	239,406	17.36
$ 3.50–$27.15	2,315,428	7.05	$12.81	1,401,428	$10.78

(11) MAJOR CUSTOMERS

During the years ended December 31, 2003, 2002 and 2001, the Company made sales to certain unrelated entities which individually comprised greater than 10% of total oil and natural gas revenues. The following is a table summarizing the percentage provided by each customer.

	Years Ended December 31,		
Customer	2003	2002	2001
A	24%	28%	46%
B	15%	29%	31%
C	—%	—%	10%
D	14%	13%	—%

At December 31, 2003, three customers represented 20%, 12% and 11%, respectively, of oil and gas sales accounts receivable.

(12) SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION

Cash paid during the years ended December 31, 2003, 2002 and 2001 for interest was approximately $9.1 million, $8.5 million and $9.2 million, respectively. See Notes 3 and 9 for additional non-cash transactions during the years ended December 31, 2003, 2002 and 2001. Cash paid for income taxes during the year ended December 31, 2003 was $0.4 million.

(13) COMMITMENTS AND CONTINGENCIES

The Company's current firm transportation commitments are 127 MMcf of gross gas sales per day. Under terms of the transportation agreements, the Company has committed to pay transportation reservation charges in consideration for firm transportation capacity rights. In addition, the Company

(13) COMMITMENTS AND CONTINGENCIES (Continued)

has various transportation agreements providing for the firm transportation in Canada. The table below sets forth the Company's firm transportation obligations for the next five years.

Years Ending December 31,	Reservation Charges
	(in thousands)
2004	$ 14,039
2005	14,063
2006	13,935
2007	13,763
2008	12,993
2009 and thereafter	49,624
	$118,417

The Company leases office space in Denver, Colorado and certain other locations in North America and also leases equipment under non-cancelable operating leases. Rental expense associated with these operating leases for the years ended December 31, 2003, 2002 and 2001 was approximately $3.5 million, $1.9 million and $1.4 million, respectively. The following table summarizes the future minimum lease payments under all noncancelable operating lease obligations.

Years Ending December 31,	Future Minimum Lease Payments
	(in thousands)
2004	$ 3,641
2005	3,370
2006	3,233
2007	3,134
2008	1,162
2009 and thereafter	330
	$14,870

The Company maintains a 401(k) plan for all eligible employees and provides a matching contribution up to a certain percentage of the employees' contributions. The 401(k) plan also provides for a profit-sharing contribution determined at the discretion of the Company. The total matching and profit-sharing contributions for the years ended December 31, 2003, 2002 and 2001 were approximately $1.1 million, $0.4 million and $0.2 million, respectively.

Evergreen was named as a defendant in a class action lawsuit filed in the Denver District Court on December 26, 2002. The plaintiffs, Mountain West Exploration, Inc., Joel Nelson and Synergy Operations Company, LLC, are royalty owners and overriding royalty owners with respect to Evergreen's Raton Basin properties who alleged in the lawsuit that amounts paid for production attributable to the royalty owners' violated the terms of the applicable leases and laws in various respects, including the value of production sold, permissibility of deductions and accuracy of quantities upon which royalties are calculated. The plaintiffs sought to recover damages and injunctive relief.

(13) COMMITMENTS AND CONTINGENCIES (*Continued*)

Due to a preliminary settlement between the parties, Evergreen recorded a $3.3 million charge to earnings in 2003. The total includes the settlement, legal fees and other associated costs. The court recently approved the preliminary settlement agreement. Final approval is expected in April 2004.

At December 31, 2003, the Company had entered into agreements with various vendors to construct well and well service equipment valued at approximately $6.9 million.

The Company has entered into agreements with certain of its officers which provide for severance payments, equal to three times the calculated average of the officer's combined annual salary and bonus, benefit continuation and accelerated vesting of options and stock grants in the event there is a change in control of the Company and the officer's employment is thereafter terminated within a two year period. The agreements expire no later than December 31, 2004, subject to automatic annual one-year renewals until cancelled by the Company.

See Note 1 for discussion of the Company's hedging obligations.

(14) RELATED PARTIES AND OTHER

On February 9, 2001, Evergreen completed a transaction with KFx Inc. ("KFx"), a provider of technology and service solutions to the electric power generation industry, under which KFx sold to Evergreen a portion of its convertible preferred stock investment in its Pegasus Technologies, Inc. subsidiary ("Pegasus") for $1.5 million, representing an approximate 8.8% as converted interest in Pegasus. On May 1, 2002, KFx repurchased the convertible preferred stock from the Company for $2 million plus accrued interest. The $0.5 million difference between the $1.5 million purchase price and the $2 million redemption price was reported as interest income ratably from February 2001 to February 2002. The Company's investment in Pegasus was classified as held-to-maturity and was carried at amortized cost. The amortized cost was adjusted for the accretion of the discount through the maturity date of the instrument. Such amortization was included in interest income as discussed above.

In connection with the purchase of the convertible preferred stock, Evergreen was provided with five-year warrants to purchase one million shares of KFx common stock at $3.65 per share, subject to certain adjustments, which included a reduction in the warrant price to $2.25 per share upon KFx's retirement of certain outstanding debentures. These debentures were retired in full by KFx in July 2002; accordingly, the warrant exercise price was reduced to $2.25 per share.

During 2003, Evergreen exercised warrants to purchase one million shares of KFx common stock at $2.25 per share and subsequently sold the one million shares at an average price of $4.88 per share. The resulting gain of approximately $2.6 million, net of transaction costs, is included in other expense in the Consolidated Statements of Operations for the year ended December 31, 2003.

The President and Chief Executive Officer of Evergreen is a director of KFx.

A director of the Company is a partner in a law firm that acts as counsel to the Company on various matters. The Company paid legal fees and expenses to the law firm of approximately $322,000, $104,000 and $157,000 during the years ended December 31, 2003, 2002 and 2001, respectively.

(15) OTHER EXPENSES, NET

The components of other expense, net include the following:

	Years Ended December 31,		
	2003	2002	2001
	(in thousands)		
Gain on sale of investment in common stock of affiliated company	$(2,627)	$ —	$ —
Gain on sale of investment in common stock of unaffiliated company	(1,321)	—	—
Loss on derivative instruments	1,168	—	—
Class action settlement, legal fees and associated costs (Note 13)	3,262	—	—
Minority interest in subsidiaries' income	1,346	4	—
Other	1,046	641	653
Total	$ 2,874	$645	$653

(16) SUPPLEMENTAL OIL AND GAS INFORMATION (Unaudited)

Costs Incurred in Oil and Gas Exploration and Development Activities

The Company's oil and gas activities are currently conducted in the United States and Canada. The Company previously had conducted operations in the United Kingdom, Northern Ireland and the Republic of Ireland, the Falkland Islands and Chile which are included in "Other International." See Notes 3, 4 and 5 for additional information regarding the Company's oil and gas properties, including the impairment of the Company's other international oil and gas properties, and asset retirement obligations. The following costs were incurred in oil and gas operation, development, production, exploration, and acquisition activities during the following periods:

	United States	Canada	Other International	Total
		(in thousands)		
Year Ended December 31, 2003				
Acquisition costs(1):				
Proved	$ 64,954	$69,377	$ —	$134,331
Unproved	8,108	2,392	—	10,500
Gas collection	—	4,700	—	4,700
Development	59,651	1,517	—	61,168
Gas collection	35,353	—	—	35,353
Exploration	47,743	3,538	2,708	53,989
Asset retirement obligation accruals:				
Acquisitions	3,045	2,422	—	5,467
Proved	4,379	29	—	4,408
Unproved	221	—	—	221
Gas collection	1,566	—	—	1,566
	$225,020	$83,975	$ 2,708	$311,703
Year Ended December 31, 2002				
Development	$ 59,378	$ —	$ —	$ 59,378
Gas collection	36,640	—	—	36,640
Exploration	9,836	—	14,617	24,453
	$105,854	$ —	$14,617	$120,471
Year Ended December 31, 2001				
Acquisition costs:				
Proved	$ 16,202	$ —	$ —	$ 16,202
Unproved	1,891	—	—	1,891
Gas collection	2,153	—	—	2,153
Development	51,512	—	—	51,512
Gas collection	35,310	—	—	35,310
Exploration	3,587	—	11,027	14,614
	$110,655	$ —	$11,027	$121,682
Years Ended December 31, 2000 and prior				
Acquisition costs:				
Proved	$153,740	$ —	$ —	$153,740
Unproved	21,904	—	—	21,904
Gas collection	34,485	—	—	34,485
Development	88,137	—	—	88,137
Gas collection	57,880	—	—	57,880
Exploration	3,157	—	23,303	26,460
	$359,303	$ —	$23,303	$382,606

(1) The 2003 acquisition costs, which are predominately related to the Company's acquisition of Carbon, include a gross-up for deferred taxes of approximately $33.4 million. See Note 3.

(16) SUPPLEMENTAL OIL AND GAS INFORMATION (Unaudited) (Continued)

The following table sets forth a summary of oil and gas property costs not being amortized at December 31, 2003, by the year in which such costs were incurred and related impairment charges:

	Total	2003	2002	2001	2000 and Prior
			(in thousands)		
Property acquisition costs	$ 34,295	$10,500	$ —	$ 1,891	$21,904
Impairment of international properties	(55,245)	(2,708)	(52,537)	—	—
Exploration and development, net of transfers to proved oil & gas properties	106,791	48,886	25,220	12,179	20,506
Total	$ 85,841	$56,678	$(27,317)	$14,070	$42,410

The following table sets forth a summary of capitalized interest that has been included in the unproved properties during the following periods:

Years Ending December 31,	United States	Other International	Total
2003	$1,293	$ —	$1,293
2002	400	988	1,388
2001	309	863	1,172
2000	134	492	626
1999 and prior	727	112	839
	$2,863	$2,455	$5,318

The Company's proved oil and gas properties and gas collection system are all located within North America. The depreciation and depletion related to these assets was $26.3 million, $20.2 million and $15.7 million for the years ended December 31, 2003, 2002 and 2001, respectively.

Oil and Gas Reserves

The estimates of the Company's proved oil and natural gas reserves and related future net cash flows that are presented in the following tables are based upon estimates made by independent petroleum engineering consultants.

The Company's reserve information was prepared as of December 31, 2003, 2002 and 2001. The Company cautions that there are many inherent uncertainties in estimating proved reserve quantities, projecting future production rates, and timing of development expenditures. Accordingly, these estimates are likely to change as future information becomes available. Proved oil and gas reserves are the estimated quantities of crude oil, condensate, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those reserves expected to be recovered through existing wells, with existing equipment and operating methods.

(16) SUPPLEMENTAL OIL AND GAS INFORMATION (Unaudited) (Continued)

Estimated quantities of proved reserves and proved developed reserves of oil and natural gas (all of which are located within North America), as well as the changes in proved reserves, are as follows:

	Reserve Quantities					
	Gas (MMcf)			Oil (Mbbls)		
	United States	Canada	Total	United States	Canada	Total
Proved reserves:						
Estimated reserves at January 1, 2001	874,526	—	874,526	—	—	—
Revisions of previous estimates	(609)	—	(609)	—	—	—
Extensions and discoveries	167,663	—	167,663	—	—	—
Production	(30,807)	—	(30,807)	—	—	—
Purchases of minerals in place	39,870	—	39,870	—	—	—
Estimated reserves at December 31, 2001	1,050,643	—	1,050,643	—	—	—
Revisions of previous estimates	(19,723)	—	(19,723)	—	—	—
Extensions and discoveries	246,870	—	246,870	—	—	—
Production	(38,988)	—	(38,988)	—	—	—
Estimated reserves at December 31, 2002	1,238,802	—	1,238,802	—	—	—
Revisions of previous estimates	(10,958)	(827)	(11,785)	(4)	(18)	(22)
Extensions and discoveries	210,015	—	210,015	—	—	—
Production	(45,703)	(470)	(46,173)	(6)	(10)	(16)
Purchase of minerals in place	61,806	33,555	95,361	700	763	1,463
Estimated reserves at December 31, 2003	1,453,962	32,258	1,486,220	690	735	1,425
Proved developed reserves:						
December 31, 2001	684,167	—	684,167	—	—	—
December 31, 2002	795,874	—	795,874	—	—	—
December 31, 2003	892,824	23,188	916,012	396	565	961

The following tables set forth a standardized measure of the estimated discounted future net cash flows attributable to the Company's proved oil and gas reserves. Oil and gas prices have fluctuated widely in recent years. The weighted average year-end spot prices utilized for the purposes of estimating the Company's proved natural gas reserves and future net revenues were $5.49, $4.22 and $2.32 per Mcf at December 31, 2003, 2002 and 2001, respectively. The weighted average year-end spot price utilized for the purposes of estimating the Company's proved oil reserves and future net revenues at December 31, 2003 was $26.08 per Bbl. Future production and development costs represent the estimated future expenditures to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expense was computed by applying statutory rates less the effects of tax credits for each period presented to the difference between pre-tax net cash flows relating to the Company's estimated proved reserves and the tax basis

(16) SUPPLEMENTAL OIL AND GAS INFORMATION (Unaudited) (Continued)

of proved properties and available net operating loss and percent depletion carryovers. The Company did not have operations in Canada until its acquisition of Carbon in 2003.

	December 31, 2003		
	United States	Canada	Total
		(in thousands)	
Future cash inflows	$ 8,022,840	$176,787	$ 8,199,627
Future production costs	(1,858,248)	(44,282)	(1,902,530)
Future development costs	(195,780)	(5,706)	(201,486)
Future income taxes	(2,045,879)	(40,347)	(2,086,226)
Future net cash flows	3,922,933	86,452	4,009,385
10% discount to reflect timing of cash flows	(2,187,827)	(36,839)	(2,224,666)
Standardized measure of discounted future net cash flows	$ 1,735,106	$ 49,613	$ 1,784,719

	December 31,	
	2002	2001
	(in thousands)	
Future cash inflows	$ 5,223,063	$2,438,286
Future production costs	(1,456,612)	(994,363)
Future development costs	(117,525)	(107,621)
Future income taxes	(1,189,050)	(402,896)
Future net cash flows	2,459,876	933,406
10% discount to reflect timing of cash flows	(1,357,836)	(515,382)
Standardized measure of discounted future net cash flows	$ 1,102,040	$ 418,024

(16) SUPPLEMENTAL OIL AND GAS INFORMATION (*Unaudited*) (*Continued*)

The following tables summarize the principal factors comprising the changes in the standardized measure of discounted future net cash flows for the years ended December 31, 2003, 2002 and 2001. The Company did not have operations in Canada until its acquisition of Carbon in 2003.

	Year Ended December 31, 2003		
	United States	Canada	Total
		(in thousands)	
Standardized measure, beginning of period	$1,102,040	$ —	$1,102,040
Sales of oil and natural gas, net of production costs	(167,079)	(1,829)	(168,908)
Extensions and discoveries	300,840	—	300,840
Net change in sales prices, net of production costs	643,484	7,747	651,231
Purchase of reserves	72,342	67,805	140,147
Revisions of quantity estimates	(20,478)	(1,865)	(22,343)
Accretion of discount	164,468	1,077	165,545
Net change in income taxes	(372,005)	(23,159)	(395,164)
Changes in future development costs	(11,167)	(547)	(11,714)
Changes in rates of production and other	22,661	384	23,045
Standardized measure, end of period	$1,735,106	$ 49,613	$1,784,719

	Years Ended December 31,	
	2002	2001
Standardized measure, beginning of period	$ 418,024	$ 1,823,751
Sales of natural gas, net of production costs	(77,196)	(92,521)
Extensions and discoveries	270,504	73,701
Net change in sales prices, net of production costs	810,055	(2,661,828)
Purchase of reserves	—	29,786
Revisions of quantity estimates	(28,000)	—
Accretion of discount	59,846	292,017
Net change in income taxes	(352,265)	915,978
Changes in future development costs	(10,701)	(8,632)
Changes in rates of production and other	11,773	45,772
Standardized measure, end of period	$1,102,040	$ 418,024

(17) SUMMARIZED QUARTERLY FINANCIAL INFORMATION (Unaudited)

The following table provides selected quarterly financial results for the years ended December 31, 2003 and 2002:

	Quarter			
	First	Second	Third	Fourth
	(in thousands)			
2003				
Total revenue	$49,121	$53,288	$ 53,967	$60,064
Total costs and expenses	31,469	34,871	34,343	42,416
Income before cumulative effect of change in accounting principle	17,652	18,417	19,624	17,648
Cumulative effect of change in accounting principle, net of tax	713	—	—	—
Net income	$16,939	$18,417	$ 19,624	$17,648
Net income per share:				
Basic:				
Income before cumulative effect of change in accounting principle	$ 0.46	$ 0.48	$ 0.50	$ 0.42
Cumulative effect of change in accounting principle, net of tax	0.02	—	—	—
Net income per share—Basic	$ 0.44	$ 0.48	$ 0.50	$ 0.42
Diluted:				
Income before cumulative effect of change in accounting principle	$ 0.45	$ 0.46	$ 0.49	$ 0.39
Cumulative effect of change in accounting principle, net of tax	0.02	—	—	—
Net income per share—Diluted	$ 0.43	$ 0.46	$ 0.49	$ 0.39
2002				
Total revenue	$20,314	$23,428	$ 29,690	$38,694
Total costs and expenses	17,930	20,138	44,686	37,696
Net income	$ 2,384	$ 3,290	$(14,996)	$ 998
Net income (loss) per share—Basic	$ 0.06	$ 0.09	$ (0.40)	$ 0.05
Net income (loss) per share—Dilutive	$ 0.06	$ 0.08	$ (0.40)	$ 0.05

The fourth quarter of 2003 includes the results of Carbon from the date of acquisition through December 31, 2003. The third and fourth quarters of 2002 include pre-tax impairment charges of $34.2 million and $17.3 million, respectively, primarily related to the Company's operations in the United Kingdom and Ireland.

GLOSSARY OF OIL AND NATUAL GAS TERMS

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

2D seismic. Seismic data that are acquired and processed to yield a two-dimensional cross-section of the subsurface.

3D seismic. Seismic data that are acquired and processed to yield a three-dimensional cross-section of the subsurface.

Average finding cost. The amount of total capital expenditures, including acquisition costs, and exploration and abandonment costs, for oil and natural gas activities divided by the amount of proved reserves added in a specified period.

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

Bcf. One billion cubic feet of natural gas at standard atmospheric conditions.

Bcfe. One billion cubic feet of natural gas equivalent at standard atmospheric conditions, determined using the ratio of one barrel of oil to six Mcf of natural gas.

Btu. British thermal unit, which is the energy required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

Coal Bed Methane ("CBM"). A form of natural gas, predominately methane, which is generated during coal formation and is contained in the coal microstructure.

Capital expenditures. Investment outlays for exploratory and development drilling (including exploratory dry holes); leasehold acquisitions; seismic data acquisitions; geological, geophysical and land related overhead expenditures; delay rentals; producing property acquisitions; other miscellaneous capital expenditures; compression equipment and pipeline costs.

Developed acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a producing horizon known to be productive.

Exploratory well. A well drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir, or to extend a known reservoir.

Coal Mine Gas. Methane that has collected in abandoned underground coal mines.

Gross acres or gross wells. The total acres or wells, as the case may be, in which the Company has a working interest.

Infill Drilling. A drilling operation in which one or more development wells is drilled within the proven boundries of a field between two or more other wells.

Lease Operating Expenses ("LOE"). All operating costs related to production activities including direct costs such as direct labor, direct materials, certain workover costs, repairs and maintenance, insurance costs, and gas collection costs.

Mbbl. One thousand Bbl.

Mcf. One thousand cubic feet of natural gas at standard atmospheric conditions.

Mcfe. One thousand cubic feet of natural gas equivalent at standard atmospheric conditions, determined using the ratio of one barrel of oil to six Mcf of natural gas.

MMcf. One thousand Mcf.

MMcfe One thousand Mcfe.

MMBtu. One million Btu.

Net acres or net wells. A net acre or well is deemed to exist when the sum of the Company's fractional ownership working interests in gross acres or wells, as the case may be, equals one. The number of net acres or wells is the sum of the fractional working interests owned in gross acres or wells, as the case may be, expressed as whole numbers and fractions thereof.

Oil. Crude oil or natural gas liquids.

Operator. The individual or company responsible to the working interest owners for the exploration, development and production of an oil or natural gas well or lease.

Present value of future net revenues or PV-10. The present value of estimated future net revenues to be generated from the production of proved reserves, net of estimated production and ad valorem taxes, future capital costs and operating expenses, using prices and costs in effect as of the date indicated, without giving effect to federal,state and provincial (foreign) income taxes. The estimated future net revenues are discounted at an annual rate of 10% to determine their "present value." The present value reflects the effect of time on the present value of the revenue stream. PV-10 should not be construed as being representative of the fair market value of the properties.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved undeveloped reserves. Reserves that can be expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Recompletion. The deepening of a well to another horizon or attempting to secure production from a shallower horizon.

Reserves. Oil and natural gas on a net revenue interest basis, estimated to be commercially recoverable. "Proved developed reserves" include proved developed producing reserves and proved developed behind-pipe reserves. "Proved developed producing reserves" include only those reserves expected to be recovered from existing completion intervals in existing wells. "Proved undeveloped reserves" include those reserves expected to be recovered from new wells on proved undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Tcf. One trillion cubic feet of natural gas at standard atmospheric conditions.

Tcfe. One trillion cubic feet of natural gas equivalent at standard atmospheric conditions, determined using the ratio of one barrel of oil to six Mcf of natural gas.

Unconventional Natural Gas. Includes CBM, tight gas sands and fractured shales. These resources have several characteristics that require special attention for successful exploration and production, thus separating them from conventional gas resources.

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

Working interest. An interest in an oil and natural gas lease that gives the owner of the interest the right to drill and produce oil and natural gas on the leased acreage and requires the owner to pay their proportionate share of the costs of drilling and production operations. The share of production to which a working interest owner is entitled will always be smaller than the share of costs that the working interest owner is required to bear, with the balance of the production accruing to governmental tax receipts and mineral interest royalties.

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OFFICERS AND DIRECTORS

MARK S. SEXTON
President, CEO
and Chairman of the Board

DENNIS R. CARLTON
Executive Vice
President–Exploration, COO
and Director

KEVIN R. COLLINS
Executive Vice President–Finance,
CFO, Treasurer and
Corporate Secretary

J. SCOTT ZIMMERMAN
Vice President–Operations
and Engineering

ALAIN G. BLANCHARD
DIRECTOR
CEO and Director
SOFICOR-MÄDER

ROBERT J. CLARK
DIRECTOR
President
Bear Cub Energy, LLC

LARRY D. ESTRIDGE
DIRECTOR
Partner, Womble Carlyle
Sandridge & Rice, PLLC

ANDREW D. LUNDQUIST
DIRECTOR
Founder and President
The Lundquist Group, LLC

JOHN J. RYAN III
DIRECTOR

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CORPORATE INFORMATION

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Communications concerning the transfer of shares, lost certificates, duplicate mailings or change of address should be directed to the transfer agent. A copy of the company's annual report on Form 10-K as filed with the Securities and Exchange Commission may be obtained without charge, upon request.

COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Evergreen's common stock trades on the New York Stock Exchange under the symbol EVG. No dividends were paid in 2002 or 2003. The table below shows the market price of the company's common stock for 2002 and 2003. The sales prices per share give effect to the two-for-one split of Evergreen's common stock effective September 16, 2003.

2002	HIGH	LOW	VOLUME (000's)
January 1 thru March 31	$ 21.83	$ 16.51	19,092
April 1 thru June 30	22.70	19.63	19,250
July 1 thru September 30	21.26	15.45	19,521
October 1 thru December 31	23.50	18.88	22,839
			80,702
2003			
January 1 thru March 31	$ 23.25	$ 20.65	23,421
April 1 thru June 30	28.50	22.30	27,951
July 1 thru September 30	28.35	24.49	31,160
October 1 thru December 31	33.75	26.60	22,542
			105,074

At February 27, 2004, the Company's 43,061,278 shares of common stock outstanding were held by approximately 1,400 shareholders of record and 11,500 shareholders whose stock is held in street name.

This report contains forward-looking statements within the meaning of federal securities laws. These statements are subject to various uncertainties. Actual results could differ materially from these forward-looking statements as a result of a variety of risks. Accordingly, there can be no assurance that actual results will be as projected in the forward-looking statements. These and other risks and uncertainties are described in more detail in the company's Annual Report on Form 10-K filed with the Securities and Exchange Commission.

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