CARBON ENERGY CORP
Form 10-K/A
September 15, 2003

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# SECURITES AND EXCHANGE COMMISSION

**Washington D.C. 20549**

# FORM 10-K/A

**Amendment No. 2**

**Annual Report Pursuant to Section 13 or 15(d)**
**of the Securities Exchange Act of 1934**

**For the Fiscal Year Ended December 31, 2002**

**Commission File Number 1-15639**

# CARBON ENERGY CORPORATION

(Exact name of Registrant as specified in its Charter)

| | |
|---|---|
| **Colorado** | **84-1515097** |
| (State of Incorporation) | (I.R.S. Employer Identification No.) |
| **1700 Broadway, Suite 1150**<br>**Denver, Colorado** | **80290** |
| (Address of principal executive offices) | (Zip Code) |

Registrants telephone number, including area code: **(303) 863-1555**

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

| Title of each class | Name of Exchange on which registered |
|---|---|
| Common Stock, (no par value) | American 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, and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

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

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

The aggregate market value of the 1,107,714 shares of voting stock held by non-affiliates of the registrant, based upon the closing sale price of the common stock on June 30, 2002 of $9.69 per share as reported on the American Stock Exchange, was $10,733,749. Shares of common stock held by each officer and director and by each person who owns 5% or more of the outstanding common stock have been excluded in that such persons may be deemed affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of March 19, 2003, the registrant had 6,150,323 shares of common stock outstanding.

## PART I

### ITEM 1. BUSINESS

*GENERAL*

Carbon Energy Corporation (the Company or Carbon) was incorporated on September 14, 1999 under the Colorado Business Corporation Act. The Company's business is comprised of the assets and properties of Carbon Energy Corporation (USA) (Carbon USA), which conducts the Company's operations in the United States and the assets and properties of Carbon Energy Canada Corporation (Carbon Canada), which conducts the Company's operations in Canada. Effective July 11, 2002, Carbon changed the name of its United States subsidiary from Bonneville Fuels Corporation (Bonneville Fuels) to Carbon Energy Corporation (USA). Effective March 1, 2003, Carbon changed the name of its Canadian subsidiary from CEC Resources Ltd. (CEC Resources) to Carbon Energy Canada Corporation. As the parent company, Carbon provides management services to Carbon USA and Carbon Canada.

Carbon is an independent oil and gas company engaged in the exploration, development and production of natural gas and crude oil in the United States and Canada. The Company's areas of operations in the United States are the Piceance Basin in Colorado, the Uintah Basin in Utah, the Permian Basin in New Mexico and Texas, and Montana. The Company's areas of operations in Canada are central Alberta and southeast Saskatchewan.

All amounts are presented in U.S. dollars unless otherwise noted.

At December 31, 2002, the Company had 67.4 billion cubic feet of natural gas equivalent ("Bcfe" where one barrel of oil is equivalent to six thousand cubic feet of gas) proved reserves compared to 59.0 Bcfe at December 31, 2001. Proved reserves at December 31, 2002 increased by 8.4 Bcfe or 14% compared to December 31, 2001. Net proved natural gas reserves totaled 62.5 Bcf of gas at December 31, 2002 compared to 53.9 Bcf at year end 2001, an increase of 8.6 Bcf or 16%. Crude oil and natural gas liquids at December 31, 2002 totaled 822,000 barrels compared to 851,000 barrels at year end 2001, a decrease of 29,000 barrels or 3%. Of these proved reserves, approximately 93% on a Mcfe basis are gas and approximately 74% are categorized as proved developed. At December 31, 2002, the pretax net present value of the reserves using year end prices and costs held constant and discounted at 10% was $106 million.

At December 31, 2002, Carbon USA's exploration and production operations were comprised of working interests in 246 producing oil and gas wells. Carbon USA operates 151 of these wells. At December 31, 2002, Carbon USA had an interest in over 179,000 net acres of oil and gas leases primarily located in the Piceance Basin of Colorado, the Uintah Basin of Utah, the Permian Basin of New Mexico and Texas, and Montana. During 2002, Carbon USA produced 3.0 Bcf of gas and 91,300 barrels of oil and natural gas liquids, amounting to 3.6 Bcfe or an average of 9.9 MMcfe per day. The addition during 2002 of 7.0 Bcfe to Carbon USA's net proved reserves resulted in a reserve replacement of 194% of the Company's 2002 production in the United States.

In September 2002, Carbon USA sold its interest in 20 producing natural gas and oil wells located primarily in Stanton and Morton counties, Kansas for $2.1 million in cash. On March 24, 2003, Carbon USA closed the sale of its interest in 97 gross (23.3 net) wells and 26,300 gross (8,000 net) acres located primarily in southeast New Mexico. The sale price was $15.7 million in cash, with an effective date of January 1, 2003. Daily average net production from the New Mexico properties was approximately 3,300 Mcf of gas per day and 130 barrels of oil per day. These asset sales completed Carbon's program to sell assets acquired in the 1999 purchase of Bonneville Fuels that did not fit with the Company's focus on the development of its natural gas properties in the Piceance and Uintah Basins and in central Alberta.

At December 31, 2002, the estimated proved reserves attributed to the properties divested in March 2003 were 172,000 barrels and 7.3 Bcf of gas. The pretax net present value of these reserves using year end 2002 prices (except to the extent provided by contractual arrangement in existence at year end) and costs held constant and discounted at 10% was $15.9 million.

At December 31, 2002, Carbon Canada's exploration and production operations were comprised of working interests in 94 producing oil and natural gas wells located in Alberta and Saskatchewan. Carbon Canada operates 51 of these wells. The Company had an interest in over 49,000 net acres of oil and gas leases. During 2002, Carbon Canada produced 2.2 Bcf of gas and 50,300 barrels of oil and natural gas liquids, amounting to 2.5 Bcfe or an average of 6.9 MMcfe per day. The addition of 9.2 Bcfe to Carbon's net proved reserves resulted in a reserve replacement of 368% of the Company's 2002 production in Canada.

For information regarding Carbon's geographic segments, see Note 7 to the Consolidated Financial Statements.

On August 11, 1999, Carbon Canada entered into a stock purchase agreement with Bonneville Pacific Corporation (BPC), parent company of Carbon USA, for the purchase of all outstanding shares of Carbon USA. Rights and obligations of Carbon Canada under the stock purchase agreement were assigned to Carbon. Yorktown Energy Partners III, LP (Yorktown) purchased 4,500,000 shares of Carbon for $24.8 million. The funds from this purchase were used to acquire, on October 29, 1999, the Carbon USA shares under the stock purchase agreement and to pay expenses incurred in connection with the purchase and related transactions. The total cash purchase price after adjustments for Carbon USA was $23.5 million.

On January 21, 2000, Carbon commenced an exchange offer for shares of Carbon Canada. Through the exchange offer, Carbon offered to exchange one share of Carbon stock for each share of Carbon Canada stock. On February 18, 2000, the Company completed its offer to exchange Carbon shares for shares of Carbon Canada. Of the 1.5 million outstanding shares of Carbon Canada, over 97% of the shares were exchanged. Carbon began trading its shares on the American Stock Exchange on February 24, 2000 under the trading symbol CRB. On February 28, 2000, at the request of Carbon Canada, the Securities and Exchange Commission (SEC) approved the delisting of Carbon Canada's common stock from the American Stock Exchange.

On November 22, 2000, at the direction of its Board of Directors, Carbon Canada initiated an offer to purchase shares (the Offer) of Carbon Canada stock that were not owned by Carbon. The Offer was completed on February 6, 2001. Carbon Canada conducted the Offer in order to avoid the administrative costs and time involved in corresponding with a small number of minority shareholders. The Board of Directors of Carbon Canada maintained a neutral position in regard to the Offer because of potential conflicts of interest. Of the approximate 39,000 shares of Carbon Canada that were not acquired by Carbon in the original exchange offer, approximately 34,000 shares of Carbon Canada stock were purchased by Carbon Canada pursuant to the Offer.

On October 30, 2002, at a special meeting of the holders of Carbon Canada common stock, a special resolution was passed to amend the articles of Carbon Canada to consolidate its issued and outstanding common shares on a one-for-2,500 basis. The Board of Directors of Carbon Canada recommended the consolidation in order to avoid the administrative costs and time involved in corresponding with a small number of minority shareholders. On November 15, 2002, Carbon Canada initiated the exchange of common shares for post-consolidation shares or a cash payment in lieu of fractional post-consolidation shares. The exchange was completed on January 13, 2003. After the completion of the exchange, Carbon owns 100% of the stock of Carbon Canada.

On March 31, 2003, Carbon announced that it had entered into an Agreement and Plan of Reorganization (the Merger Agreement) with Evergreen Resources (Evergreen). Under the Merger Agreement, Carbon will merge with a subsidiary of Evergreen, and Carbon shareholders will receive .275 shares of Evergreen common stock for each outstanding share of Carbon common stock (and cash in lieu of any fractional shares). As a result of the merger, Carbon will become a wholly owned subsidiary of Evergreen. The merger is intended to be a tax-free, stock-for-stock transaction.

The Board of Directors of Carbon and Evergreen each unanimously approved the Merger Agreement. At the time of execution of the agreement, each of Yorktown and Patrick R. McDonald, President and Chief Executive Officer of Carbon, who beneficially own approximately 73.2% and 6.0%, respectively, of Carbon's outstanding common stock, has executed an agreement with Evergreen obligating each of them to vote all shares over which it has voting control in favor of the merger.

RBC Capital Markets acted as the financial advisor to Carbon and rendered a fairness opinion to the Board of Directors of Carbon.

Completion of the merger, which is subject to customary conditions, including approval by the shareholders of Carbon, is expected to occur late in the second quarter or in the third quarter of 2003. The Merger Agreement contains a $2.5 million termination fee payable by Carbon if the Merger Agreement is terminated under certain circumstances.

*BUSINESS STRATEGY*

The Company's objective is to build shareholder value through consistent growth in reserves and production and to increase net asset value, cash flow, and earnings per share. Our business strategy is to grow through the exploration and development of oil and gas properties, by the acquisition of complementary properties and through the optimization of gathering, compression and processing facilities. In addition we seek opportunities to acquire additional oil and gas mineral leases and create drilling opportunities based on internally generated geological and engineering concepts. Management believes that the Company's existing infrastructure and its acreage position in the Piceance Basin in Colorado and the Uintah Basin in Utah and the Carbon and Rowley areas of Alberta, Canada provide the Company with an excellent opportunity to achieve its objectives. The Company may also pursue property acquisition opportunities in its areas of operations. The Company's objective and business strategy is subject to the proposed merger described above.

*EMPLOYEES AND OFFICES*

As of December 31, 2002, the Company had 24 employees located in Denver, Colorado and 12 in Calgary, Alberta. None of these employees are represented by a labor union. The Company's executive offices are located at 1700 Broadway, Suite 1150, Denver, Colorado 80290, and its telephone number is (303) 863-1555.

## ITEM 2. PROPERTIES

*United States*

Piceance and Uintah Basins At December 31, 2002, Carbon owned working interests in 148 gross (128.7 net) producing wells in the Piceance Basin of Colorado and Uintah Basin of Utah. Carbon operates 132 of these wells. For the year ended December 31, 2002, the Company participated in the drilling of three gross (2.7 net) wells, all of which were completed as natural gas wells. The Company has leasehold rights in approximately 147,000 gross (126,000 net) acres of which approximately 108,000 gross (93,000 net) acres are undeveloped. Approximately 77,000 gross (62,000 net) undeveloped acres are held by production. Subject to completion of the proposed merger described previously, Carbon USA's focus in the United States during 2003 is to continue the development of its natural gas properties in the Rocky Mountains, with emphasis on the Piceance and Uintah Basins.

Permian Basin At December 31, 2002, Carbon owned working interests in 97 gross (23.3 net) producing wells in the Permian Basin of New Mexico and Texas. Carbon operates 18 of these wells. For the year ended December 31, 2002, the Company participated in the drilling of six gross (.7 net) wells, of which one gross (.1 net) was completed as a natural gas well, four gross (.3 net) were completed as oil wells and one gross (.3 net) was abandoned as a dry hole. The Company has leasehold rights in approximately 25,000 gross (8,000 net) acres of which approximately 8,000 gross (4,000 net) acres are undeveloped. Approximately 8,000 gross (2,000 net) undeveloped acres are held by production. In March 2003, Carbon USA sold its working and related leasehold interests in these properties.

Montana At December 31, 2002, Carbon owned a working interest and operated one gross (1.0 net) producing well in Montana. For the year ended December 31, 2002, the Company participated in the drilling of two gross (2.0 net) wells both of which were abandoned as dry holes. The Company has leasehold rights in approximately 47,000 gross (44,000 net) acres, approximately all of which are undeveloped.

*Canada*

Alberta At December 31, 2002, Carbon owned working interests in 85 gross (58.4 net) producing wells primarily in the Carbon and Rowley areas of Alberta. Carbon operates 51 of these wells. For the year ended December 31, 2002, the Company participated in the drilling of 17 gross (10.5 net) wells, resulting in 16 gross (10.0 net) natural gas wells and one gross (.5 net) dry hole. The Company has leasehold rights in approximately 76,000 gross (49,000 net) acres of which approximately 27,000 gross (22,000 net) acres are undeveloped. Subject to completion of the proposed merger described previously, Carbon's focus in Canada during 2003 is to continue the development of its natural gas properties in central Alberta, with emphasis on the Carbon and Rowley areas.

Saskatchewan At December 31, 2002, Carbon owned non-operating working interests in nine gross (2.8 net) producing wells in southeast Saskatchewan. For the year ended December 31, 2002, the Company did not participate in any drilling activities in this area. The Company has leasehold rights in approximately 2,000 gross (500 net) acres of which approximately 160 gross (40 net) acres are undeveloped.

*RESERVES*

The table below sets forth the Company's estimated quantities of historical proved reserves after royalty burdens and the present values attributable to those reserves as of December 31, 2002, 2001 and 2000. The estimates for the Company's reserves in the United States were prepared by Ryder Scott Company, an independent reservoir engineering firm. The estimates for the Company's reserves in Canada were prepared by Sproule Associates Limited, independent geological and petroleum engineering consultants. Additional information regarding the Company's proved and proved developed oil and gas reserves and the standardized measure of discounted net cash flow and changes therein are described in Note 13 to the Consolidated Financial Statements.

| | **United States** | | | **Canada** | | |
|---|---|---|---|---|---|---|
| | **2002** | **2001** | **2000** | **2002** | **2001** | **2000** |
| | **(dollars in thousands, except price data)** | | | | | |
| Estimated proved reserves | | | | | | |
| Natural gas (MMcf) | 36,677 | 33,992 | 32,100 | 25,805 | 19,868 | 18,867 |

| | United States | | | Canada | | |
|---|---|---|---|---|---|---|
| Oil and liquids (MBbl) | 265 | 412 | 507 | 557 | 439 | 461 |
| Total MMcfe | 38,267 | 36,464 | 35,142 | 29,147 | 22,502 | 21,633 |
| Proved developed reserves (MMcfe)(1) | 29,991 | 31,355 | 28,714 | 19,959 | 16,822 | 18,659 |
| Natural gas price as of December 31 ($/Mcf) | $ 3.14 | $ 2.25 | $ 9.76 | $ 3.84 | $ 2.30 | $ 9.00 |
| Oil and liquids price as of December 31 ($/Bbl) | 29.84 | 18.45 | 25.50 | 24.68 | 13.02 | 21.73 |
| Present value of estimated future net revenues before future income taxes, discounted at 10% | $ 42,264 | $ 31,107 | $ 153,528 | $ 63,912 | $ 24,684 | $ 111,461 |

(1) Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

The estimate of net proved reserves in the United States at December 31, 2000 included volumes attributed to the Company's working interest in 40 natural gas wells located in the San Juan Basin of New Mexico. These properties were sold in January 2001. The estimated proved reserves attributed to these properties were 38,000 barrels of oil and 5.6 Bcf of natural gas. The pretax net present value of these reserves using year end 2000 prices (except to the extent provided by contractual arrangements in existence at year end) and costs held constant and discounted at 10% was $24.0 million.

The estimate of proved reserves in the United States at December 31, 2002 included volumes attributed to the Company's working interest in 97 gross (23.3 net) wells located primarily in southeast New Mexico. These properties were sold in March 2003. The estimated proved reserves for these properties were 172,000 barrels of oil and 7.3 Bcf of gas. The pretax net present value of these reserves using year end 2002 prices (except to the extent provided by contractual arrangements in existence at year end) and costs held constant and discounted at 10% was $15.9 million.

Reserve estimates are based upon various assumptions, including assumptions required by the Securities and Exchange Commission 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. 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 its control.

In accordance with applicable requirements of the SEC, estimates of the Company's future net revenues are determined using sale prices estimated to be in effect as of the date of the reserve estimates and are held constant throughout the life of the properties (except to the extent provided by contractual arrangements in existence at year end). Also in accordance with the applicable SEC guidelines, future production costs are held constant at the level observed at the date of the reserve estimates. Declines in the price of oil or gas decrease reserve values by lowering the future net revenues attributable to the reserves and may also reduce the quantities of reserves that are recoverable on an economic basis. Price increases may have the opposite effect. A significant decline in prices of natural gas or oil could have a material adverse effect on the Company's financial condition and results of operations. Prices received for future production and future production costs may vary, perhaps significantly, from the prices and costs assumed for purposes of the estimates.

In general, the volumes of production from Carbon's oil and gas properties decline as reserves of oil and gas are depleted. Except to the extent the Company acquires additional properties containing proved reserves or conducts successful exploration and development activities or both, the proved reserves of the Company will decline as reserves are produced. Reserves generated from future activities of the Company are highly dependent upon the level of success in acquiring or discovering additional reserves and the costs incurred in doing so.

Since January 1, 2002, the Company has filed the Department of Energy Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," as required by operators of oil and gas properties in the United States. There are differences between the reserves as reported on Form

EIA-23 and reserves as reported herein. Form EIA-23 requires that operators report on total proved reserves for operated wells only and that reported reserves be reported on a gross basis rather than on a net basis.

*PRODUCTION*

The following table sets forth information regarding net oil and natural gas production, average sales prices and other production information. Average sales prices for natural gas, oil and liquids are inclusive of hedging gains and losses for the years ended December 31, 2002, 2001 and 2000:

| | United States | | | Canada(1) | | |
|---|---|---|---|---|---|---|
| | 2002 | 2001 | 2000 | 2002 | 2001 | 2000 |
| Quantities produced and sold | | | | | | |
| Natural gas (MMcf) | 3,049 | 2,810 | 3,374 | 2,232 | 2,419 | 1,312 |
| Oil and liquids (Bbl) | 91,297 | 81,091 | 69,394 | 50,274 | 58,615 | 39,662 |
| Total MMcfe | 3,597 | 3,297 | 3,790 | 2,534 | 2,771 | 1,550 |
| Average sales price | | | | | | |
| Natural gas ($/Mcf) | $ 2.17 | $ 2.94 | $ 2.80 | $ 2.95 | $ 4.05 | $ 3.41 |
| Oil and liquids ($/Bbl) | 21.92 | 25.49 | 23.03 | 19.62 | 21.76 | 22.65 |
| Average production (lifting) costs ($/Mcfe) | $ 0.45 | $ 0.50 | $ 0.42 | $ 0.67 | $ 0.58 | $ 0.51 |

(1) Canadian results for 2000 are the results of Carbon Canada subsequent to its acquisition by Carbon in February 2000.

*PRODUCTIVE WELLS*

The following table sets forth information regarding the number of productive wells in which the Company held a working interest at December 31, 2002:

| | Productive Wells(1) | | | |
|---|---|---|---|---|
| | Gas Wells | | Oil Wells | |
| | Gross(2) | Net(3) | Gross | Net |
| United States | | | | |
| Permian Basin | 61 | 13.6 | 36 | 9.7 |
| Piceance/Uintah Basins | 145 | 125.7 | 3 | 3.0 |
| Montana | | | 1 | 1.0 |
| Total | 206 | 139.3 | 40 | 13.7 |
| Canada | | | | |
| Alberta | 85 | 58.4 | | |
| Saskatchewan | | | 9 | 2.8 |
| Total | 85 | 58.4 | 9 | 2.8 |
| United States and Canada | 291 | 197.7 | 49 | 16.5 |

**Productive Wells(1)**

(1) Each well completed to more than one producing zone is counted as a single well. The Company has royalty interests in certain wells that are not included in this table.

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

(3) A net well is deemed to exist when the sum of fractional ownership working interests in gross wells equals one. The number of net wells is the sum of the fractional working interest owned in gross wells.

The number of productive wells in which the Company held a working interest at December 31, 2002 included 61 gross (13.6 net) gas wells and 36 gross (9.7 net) oil wells attributed to properties located primarily in southeast New Mexico. These properties were sold in March 2003.

*DRILLING ACTIVITY*

The Company engages in exploratory and developmental drilling on its own and in association with other oil and gas companies. The following table sets forth the wells drilled for the years ended December 31, 2002, 2001 and 2000:

| | United States | | | Canada(1) | | |
|---|---|---|---|---|---|---|
| | 2002 | 2001 | 2000 | 2002 | 2001 | 2000 |
| Gross wells(2) | | | | | | |
| Development | | | | | | |
| Natural gas | 2 | 6 | | 14 | 11 | 8 |
| Oil | 4 | 7 | 6 | | | |
| Non-productive(3) | | | | 1 | | |
| Total | 6 | 13 | 6 | 15 | 11 | 8 |
| Exploratory | | | | | | |
| Natural gas | 2 | 16 | | 2 | | |
| Oil | | 3 | 4 | | | |
| Non-productive | 3 | 3 | 5 | | | |
| Total | 5 | 22 | 9 | 2 | | |
| Net wells(4) | | | | | | |
| Development | | | | | | |
| Natural gas | 1.8 | 4.7 | | 9.0 | 10.5 | 4.9 |
| Oil | 0.3 | 2.5 | 0.4 | | | |
| Non-productive | | | | 0.5 | | |
| Total | 2.1 | 7.2 | 0.4 | 9.5 | 10.5 | 4.9 |
| Exploratory | | | | | | |

| | United States | | | Canada(1) | | |
|---|---|---|---|---|---|---|
| Natural gas | 1.0 | 10.1 | | 1.0 | | |
| Oil | 2.5 | 2.5 | | | | |
| Non-productive | 2.3 | 2.5 | 3.8 | | | |
| Total | 3.3 | 15.1 | 6.3 | 1.0 | | |

(1) The results for 2000 are the results of Carbon Canada subsequent to its acquisition by Carbon in February 2000.

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

(3) A non-productive hole is a well deemed to be incapable of producing either natural gas or oil in sufficient quantities to justify completion as a natural gas or oil well.

(4) A net well is deemed to exist when the sum of the fractional ownership working interests in gross wells equals one. The number of net wells is the sum of the fractional working interest owned in gross wells.

At December 31, 2002, the Company was participating in the drilling of one gross (.1 net) well in the United States and three gross (2.8 net) wells in Canada.

*DEVELOPED AND UNDEVELOPED ACREAGE*

The following table sets forth the leasehold acreage held by the Company at December 31, 2002:

| | Developed Acreage(1) | | Undeveloped Acreage(2) | |
|---|---|---|---|---|
| | Gross(3) | Net(4) | Gross | Net |
| United States | | | | |
| Permian Basin | 17,201 | 4,664 | 8,150 | 3,550 |
| Piceance and Uintah Basins | 38,208 | 32,735 | 108,424 | 92,786 |
| Montana | 40 | 40 | 46,748 | 43,706 |
| Wyoming | 1,120 | 560 | 2,221 | 1,111 |
| Total | 56,569 | 37,999 | 165,543 | 141,153 |
| Canada | | | | |
| Alberta | 48,480 | 27,448 | 27,360 | 21,564 |
| Saskatchewan | 1,520 | 432 | 160 | 40 |
| Total | 50,000 | 27,880 | 27,520 | 21,604 |

(1)

Developed acres are those acres which are spaced or assigned to productive wells.

(2) Undeveloped acres are considered to be those 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 such acreage contains proved reserves. It should not be confused with undrilled acreage held by production under the terms of a lease.

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

(4) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres.

The developed and undeveloped acreage position in the United States at December 31, 2002 included 17,201 gross (4,664 net) developed acres, and 8,150 gross (3,550 net) undeveloped acres attributed to lands located primarily in southeast New Mexico. These properties were sold in March 2003.

*MARKETING*

The Company sells natural gas, oil and natural gas liquids production from wells that it operates directly to purchasers including end users, marketers and refiners. Where the Company is not the operator of the well, it may directly market the production or it may contract to sell its share of production through the operator of the well.

The Company generally enters into short-term natural gas sales contracts and is typically paid a price based on the regional price set by the market place for natural gas deliveries to the regional interstate mainline transportation pipeline, a price which is generally less than the price set for natural gas deliveries to Henry Hub, the principal point for natural gas production in the Gulf Coast region of the United States and the point at which the price of the natural gas contract of the New York Mercantile Exchange (NYMEX) is set. The Company is typically paid on an index basis, net of mainline transportation charges incurred by the buyer. As of December 31, 2002, Carbon Canada is a party to various natural gas transportation contracts in Canada. Carbon Canada typically assigns these transportation contracts to the buyer of the Company's natural gas production for the term of the particular contract. The rights and obligations under these transportation agreements revert to the Company upon expiration of the natural gas sales contracts.

In the United States, oil is sold under contracts extending up to a year based upon monthly refiner price postings, which generally approximate the price of West Texas Intermediate crude oil 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.

For information regarding major purchasers of the Company's oil and natural gas, see Note 8 to the Consolidated Financial Statements.

*COMPETITION*

The oil and natural gas industry is highly competitive. The Company encounters competition from other oil and natural gas companies including major oil companies, other independent oil and natural gas concerns and individual producers and operators for the acquisition of producing properties and exploration and development prospects. The Company also competes with other oil and natural gas companies in attempting to secure drilling rigs and other equipment necessary for drilling and completion of wells. The Company competes with a large number of companies having substantially larger technical staffs and greater financial and operational resources. The ability of the Company to increase reserves in the future will be dependent on its ability to generate successful prospects on its existing lands, to acquire producing properties and to acquire additional leases and prospects for future development and exploration.

*TITLE TO PROPERTIES*

Title to the Company's properties is subject to royalty, overriding royalty, carried, net profits, working and similar interests customary in the oil and gas industry. The Company's properties may also be subject to liens incident to operating agreements, as well as other customary encumbrances, easements and restrictions and for current taxes not yet due. For acquisitions of properties, the Company will conduct a title examination on all material properties. Prior to the commencement of drilling operations, a title examination and, if necessary, curative work will be performed. The methods of title examination adopted by the Company are reasonable in the opinion of management and are designed to insure that production from its properties, if obtained, will be salable for the account of the Company.

*GOVERNMENT REGULATION*

*United States*

The Company's United States operations are regulated at the federal, state and local levels. Natural gas and oil exploration, development, production and marketing activities are subject to various laws and regulations which may be periodically changed for a variety of political, economical and other reasons.

In the past, the federal government has regulated the prices at which oil and natural gas could be sold. The Natural Gas Wellhead Decontrol Act of 1989 removed all price controls affecting producing wellhead sales effective January 1, 1993. While sales by producers of oil, natural gas, and natural gas liquids can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. The Company's natural gas sales are affected by regulation of intrastate and interstate transportation. In recent years the Federal Energy Regulatory Commission (FERC) has issued a series of orders that has increased competition by, among other things, removing the transportation barriers to market access. These orders have had a significant impact upon gas markets in the United States and have fostered the development of a large spot market for gas and increased competition for gas markets. As a result of the FERC orders, producers can access gas markets directly but face increased competition for these markets. The Company believes that these changes have generally improved the Company's access to transportation and has enhanced the marketability of its natural gas production. To date the Company believes it has not experienced any material adverse effects as a result of these FERC orders; however the Company cannot predict what new regulations may be adopted by FERC and other regulatory authorities and the effect, if any, subsequent regulations may have on the Company.

The Company's oil and natural gas operations are regulated by administrative agencies under statutory provisions of the states where such operations are conducted and by certain agencies of the Federal government for operations on federal oil and gas leases. All of the jurisdictions in which the Company owns or operates producing oil and natural gas properties have statutory provisions regulating the exploration for and production of crude oil and natural gas. These statutes include the regulation of the size of drilling and spacing units and the number of wells which may be drilled in an area and the unitization or pooling of oil and natural gas properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, typically prohibit the venting or flaring of natural gas, and impose certain requirements regarding the apportionment of production from fields and individual wells. The effect of these regulations may limit the amount of oil and natural gas the Company can produce from its wells and limit the number of wells or location at which the Company can drill. State commissions establish rules for reclamation of sites, plugging bonds, reporting and other matters.

Increasingly, a number of city and county governments have enacted oil and natural gas regulations which have increased the involvement of local governments in the permitting of oil and natural gas operations and impart additional restrictions or conditions on the conduct of operators to mitigate the impact of operations on the local community. These local restrictions have the potential to delay and increase the cost of oil and natural gas operations.

*Canada*

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 in by virtue of the Alberta Royalty Tax Credit (ARTC). 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 REGULATION*

*United States*

The Company, as a lessee and operator of natural gas and oil properties, is subject to various federal, state and local laws and regulations in the United States that provide for restriction and prohibition on releases or emissions of various substances produced in association with certain oil and gas industry operations which can affect the location of wells and facilities and can determine the extent to which exploration and development is permitted. In addition, legislation requires that well and facility sites and access be abandoned and reclaimed to the satisfaction of federal or state authorities, as applicable. These laws and regulations may, among other things, impose liability and penalties on the lessee for the cost of pollution cleanup resulting from operations, subject the lessee to liability for pollution damages, require suspension or cessation of operations in affected areas, and impose restrictions on the injection of liquids into subsurface aquifers that may contaminate ground water.

The Company has made, and will continue to make, expenditures in its efforts to comply with environmental regulations. The Company believes it is in compliance with applicable environmental laws and regulations in effect and that continued compliance with existing requirements will not have a material adverse impact on the Company. The Company has not been notified of, nor has any knowledge of any existing or pending environmental claims. Changes in existing environmental laws or the adoption of new environmental laws could have the potential to adversely affect the Company's operations. In connection with the Company's acquisition of Carbon USA, environmental assessments of Carbon USA's oil and gas properties were performed. No material noncompliance or clean-up liabilities requiring action were discovered. However, environmental assessments were performed on only a percentage of the Company's properties according to the value of the properties established at the time of acquisition.

The Company believes that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. No assurance can be given as to future capital expenditures which may be required for compliance with prospective environmental regulations.

*Canada*

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 Environmental Protection and Enhancement Act imposes environmental standards and requires compliance with various legislative criteria including reporting and monitoring in Alberta. 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.

*OPERATING HAZARDS*

The oil and gas industry involves a variety of operating risks including the risk of fire, explosion, blow-outs, pipe failure, casing collapse, abnormally pressured formations, and environmental hazards such as oil spills, gas leaks, ruptures and discharge of toxic substances. The occurrence of any of these events might result in substantial losses to the Company due to injury and loss of life, severe damage to and destruction of property and natural resources and investigation and penalties and suspension of operations. The Company maintains insurance against some, but not all, potential risks. There can be no assurance that any such insurance that is obtained will be adequate to cover all losses or exposure for liability. Furthermore, the Company cannot predict whether such insurance will continue to be available at premium levels that justify its purchase.

**ITEM 3. LEGAL PROCEEDINGS**

Neither the Company nor its subsidiaries are engaged in any material legal proceedings.

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

None.

## PART II

**ITEM 5. MARKET FOR REGISTRANTS COMMON EQUITY AND RELATED STOCKHOLDER MATTERS**

On February 24, 2000, Carbon Energy shares began trading on the American Stock Exchange under the trading symbol CRB. The Company's equity securities consist of common stock with no par value. The range of the high and low closing prices of the Company's common stock for each quarterly period during 2002 and 2001 is as follows:

| Quarter Ended | High | Low |
|---|---|---|
| March 31, 2002 | $ 8.69 | $ 7.90 |
| June 30, 2002 | 9.90 | 8.60 |
| September 30, 2002 | 9.89 | 9.50 |
| December 31, 2002 | 10.25 | 9.70 |
| | | |
| March 31, 2001 | $ 8.80 | $ 6.81 |
| June 30, 2001 | 12.31 | 8.80 |
| September 30, 2001 | 9.90 | 8.20 |
| December 31, 2001 | 9.59 | 8.60 |

On March 19, 2003, the closing price of the common stock was $10.50. There were approximately 40 holders of record of the common stock and 6.1 million shares outstanding.

The Company has not paid dividends on its common stock since inception and does not anticipate doing so in the future. Future payments of dividends, if any, will depend on the Company's earnings, capital requirements, loan restrictions, financial condition and other relevant factors. There is no assurance that the Company will ever pay dividends.

## ITEM 6. SELECTED FINANCIAL DATA

The table below sets forth selected historical financial and operating data for Carbon and its predecessor, Bonneville Fuels, as of or for each of the years in the five-year period ended December 31, 2002. For 1999, the table presents the activities of the Company for November and December 1999 (the Company's operating activities prior to November 1, 1999 were minimal) and Carbon's predecessor, Bonneville Fuels, for the period January through October 1999, and a pro forma presentation for the combined operating and cash flow data for the year ended December 31, 1999. The twelve month figures as of or for the year ended December 31, 1998 are for Carbon's predecessor, Bonneville Fuels. Future results may differ substantially from historical results because of changes in oil and natural gas prices, production increases or declines and other factors. This information should be read in conjunction with the financial statements and notes thereto and "Management's Discussion and Analysis of Financial Condition and Results of Operations," presented elsewhere herein. Please see Note 7 and Note 14 to the Consolidated Financial Statements for information on geographic segments and quarterly data for 2002 and 2001.

| | As of or for the Year Ended December 31, | | | Pro Forma for the Year Ended December 31, 1999 | As of or for the Two Months Ended December 31, 1999 | As of or for the Ten Months Ended October 31, 1999 | As of or for the Year Ended December 31, 1998 |
|---|---|---|---|---|---|---|---|
| | 2002 | 2001 | 2000 | | | | |
| | (dollars in thousands, except per share data) | | | | | | |
| Operating Data: | | | | | | | |
| Revenues | $ 18,071 | $ 23,069 | $ 17,649 | $ 11,136 | $ 1,915 | $ 9,221 | $ 7,912 |
| Net earnings (loss) | (14,555) | 1,573 | 1,456 | 147 | (491) | 638 | (2,191) |
| Earnings (loss) per share: | | | | | | | |
| Basic | $ (2.39) | $ 0.26 | $ 0.25 | n/a | $ (0.12) | n/a | n/a |
| Diluted | (2.39) | 0.25 | 0.25 | n/a | (0.12) | n/a | n/a |
| Balance Sheet Data: | | | | | | | |
| Total assets | $ 52,304 | $ 62,368 | $ 62,480 | n/a | $ 39,298 | $ 22,912 | $ 22,840 |
| Working capital | (3,671) | (5,051) | (267) | n/a | 232 | 1,954 | 562 |
| Long-term debt | 22,709 | 17,870 | 15,082 | n/a | 9,100 | 9,800 | 5,850 |
| Stockholders' equity | 18,608 | 33,854 | 32,235 | n/a | 24,315 | 9,701 | 9,063 |
| Cash Flow Data: | | | | | | | |
| Cash provided by (used in) operating activities | $ 2,657 | $ 14,232 | $ 3,755 | $ (713) | $ 999 | $ (1,712) | $ 4,696 |

| | As of or for the Year Ended December 31, | | | | | | |
|---|---|---|---|---|---|---|---|
| Cash used in investing activities | (7,572) | (17,297) | (8,266) | (28,841) | (24,110) | (4,731) | (5,948) |
| Cash provided by financing activities | 4,875 | 3,089 | 3,526 | 28,056 | 24,106 | 3,950 | 3,450 |
| EBITDA(1) | (6,612) | 10,734 | 8,763 | 3,423 | 239 | 3,184 | (42) |

(1) Net earnings (loss) to EBITDA reconciliation:

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Net earnings (loss) | $ (14,555) | $ 1,573 | $ 1,456 | $ 147 | $ (491) | $ 638 | $ (2,191) |
| Interest | 1,054 | 836 | 1,104 | 556 | 102 | 454 | 238 |
| Income taxes | 747 | 2,091 | 667 | | | | (175) |
| Depreciation, depletion & amortization | 6,142 | 6,234 | 5,536 | 2,720 | 628 | 2,092 | 2,086 |
| EBITDA | $ (6,612) | $ 10,734 | $ 8,763 | $ 3,423 | $ 239 | $ 3,184 | $ (42) |

EBITDA (as used herein) is defined as net income (loss) before interest expense, income taxes, and depletion, depreciation and amortization. While EBITDA should not be considered in isolation or as a substitute for net income (loss), operating income (loss), cash flow provided by operating activities or other income or cash flow data prepared in accordance with generally accepted accounting principles or as an indicator of a company's financial performance, the Company believes that it provides additional information with respect to its ability to meet its future debt service, capital expenditures and working capital requirements. When evaluating EBITDA, readers should consider, among other factors, (i) increasing or decreasing trends in EBITDA, (ii) whether EBITDA has remained at positive levels historically and (iii) how EBITDA compares to levels of interest expense. While the Company believes that EBITDA may provide additional information with respect to its ability to meet its future debt service, capital expenditures and working capital requirements, certain functional or legal requirements of its business may require it to utilize its available funds for other purposes.

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

*RESULTS OF OPERATIONS COMPARISON OF 2002 RESULTS TO 2001*

The following table and discussion present comparative revenue, sales volumes, average sales prices, expenses and the percentage change between periods for the years ended December 31, 2002 and 2001.

| | United States For the Year Ended December 31, | | | Canada For the Year Ended December 31, | | |
|---|---|---|---|---|---|---|
| | 2002 | 2001 | Change | 2002 | 2001 | Change |
| | (Dollars in thousands, except prices and per Mcfe information) | | | (Dollars in thousands, except prices and per Mcfe information) | | |
| Revenues: | | | | | | |
| Oil and gas revenues | $ 10,154 | $ 11,455 | -11% | $ 7,573 | $ 11,080 | -32% |
| Marketing and other, net | 344 | 532 | -35% | | 2 | n/a |
| Total revenues | 10,498 | 11,987 | -12% | 7,573 | 11,082 | -32% |
| Daily sales volumes: | | | | | | |
| Natural gas (MMcf) | 8.4 | 7.7 | 9% | 6.1 | 6.6 | -8% |
| Oil and liquids (Bbl) | 250 | 222 | 13% | 138 | 161 | -14% |
| Equivalents production (MMcfe 6:1) | 9.9 | 9.0 | 10% | 6.9 | 7.6 | -9% |

| | United States For the Year Ended December 31, | | | Canada For the Year Ended December 31, | | |
|---|---|---|---|---|---|---|
| Average price realized: | | | | | | |
| Natural gas (Mcf) | $ 2.67 | $ 3.34 | -20% | $ 2.95 | $ 4.05 | -27% |
| Oil and liquids (Bbl) | 21.92 | 25.49 | -14% | 19.62 | 21.76 | -10% |
| Direct lifting costs | $ 1,623 | $ 1,654 | -2% | $ 1,703 | $ 1,612 | 6% |
| Average direct lifting costs/Mcfe | 0.45 | 0.50 | -10% | 0.67 | 0.58 | 16% |
| Other production costs | 3,170 | 3,015 | -5% | 82 | 14 | 486% |
| General and administrative, net | 2,868 | 2,767 | 4% | 2,019 | 1,736 | 16% |
| Depreciation, depletion and amortization | 3,626 | 3,536 | 3% | 2,516 | 2,698 | -7% |
| Full cost ceiling impairment | 12,003 | | n/a | 1,215 | | n/a |
| Interest and other expense, net | 804 | 653 | 23% | 250 | 210 | 19% |
| Income tax provision | 746 | 135 | 453% | 1 | 1,956 | -100% |

Revenues for oil and gas sales of Carbon USA for the year ended December 31, 2002 were $10.2 million, an 11% decrease from 2001. The decrease was due to a decline in oil and natural gas prices partially offset by increased oil, liquids and natural gas production.

Revenues for oil, liquids and gas sales of Carbon Canada for the year ended December 31, 2002 were $7.6 million, a 32% decrease from 2001. The decrease was due primarily to a decline in oil, liquids and natural gas prices and a decrease in oil, liquids and natural gas production largely due to the voluntary curtailment in the third quarter of 2002 of over 200 MMcf of the Company's natural gas and associated natural gas liquids production due to low natural gas prices.

Average production in the United States for the year ended December 31, 2002 was 250 barrels of oil per day and 8.4 million cubic feet (MMcf) of gas per day, an increase of 10% from 2001 on a Mcf equivalent (Mcfe) basis where one barrel of oil or liquids is equal to six Mcf of gas. The increase in oil, liquids and gas production was due to successful drilling activities conducted in the Piceance and Permian Basins, partially offset by natural production declines. Due to low natural gas prices in the Piceance and Uintah Basins, the Company delayed the completion and pipeline connection of several newly drilled wells until the latter part of 2002. For the year ended December 31, 2002, Carbon USA participated in the drilling of 11 gross (5.4 net) wells of which four gross (.3 net) were completed as oil wells, four gross (2.8 net) were completed as gas wells, and three gross (2.3 net) wells were abandoned as dry holes. For the year ended December 31, 2001, Carbon USA participated in the drilling of 35 gross (22.3 net) wells of which ten gross (5.0 net) were completed as oil wells, 22 gross (14.8 net) were completed as gas wells and three gross (2.5 net) wells were abandoned as dry holes.

Average production in Canada for the year ended December 31, 2002 was 138 barrels of oil and liquids per day and 6.1 MMcf of gas per day, a decrease of 9% from 2001 on an Mcfe basis. The decrease was due primarily to the voluntary curtailment of natural gas and liquids production during the third quarter of 2002 and natural production declines in all operating areas, partially offset by successful drilling activities in the Carbon and Rowley areas of central Alberta. In addition, due to low natural gas prices in central Alberta, the Company delayed the completion and pipeline connection of several newly drilled wells until the fourth quarter of 2002. For the year ended December 31, 2002, Carbon Canada participated in the drilling of 17 gross (10.5 net) wells of which 16 gross (10.0 net) were completed as gas wells and one gross (.5 net) well was abandoned as a dry hole. For the year ended December 31, 2001, Carbon Canada participated in the drilling of 11 gross (10.5 net) wells all of which were completed as gas wells.

Average oil and liquids prices realized by Carbon USA decreased 14% from $25.49 per barrel for the year ended December 31, 2001 to $21.92 for 2002. The average oil price includes hedge losses of $83,000 or $.90 per barrel for the year ended December 31, 2002 compared to hedge gains of $25,000 or $.30 per barrel for 2001. Average natural gas prices realized by Carbon USA decreased 20% from $3.34 per Mcf for the year ended December 31, 2001 to $2.67 per Mcf for 2002. The average natural gas price includes hedge gains of $400,000 or $.14 per Mcf for the year ended December 31, 2002 compared to hedge losses of $1.5 million or $.53 per Mcf for 2001.

Average oil and liquids prices realized by Carbon Canada decreased 10% from $21.76 per barrel for the year ended December 31, 2001 to $19.62 for 2002. The average oil and liquids price includes hedge losses of $8,000 or $.16 per barrel for the year ended December 31, 2002 compared to hedge gains of $33,000 or $.56 per barrel for 2001. Average natural gas prices realized by Carbon Canada decreased 27% from $4.05 per Mcf for the year ended December 31, 2001 to $2.95 for 2002. The average natural gas price includes hedge gains of $3,000 for the year ended December 31, 2002 compared to hedge losses of $571,000 or $.24 per Mcf for 2001.

Marketing and other revenues for Carbon USA decreased 35% from $532,000 for the year ended December 31, 2001 to $344,000 for 2002. Marketing revenue for the year ended December 31, 2001 included mark-to-market gains of $1.2 million related to a derivative contract that did not qualify for hedge accounting treatment under provisions of Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities." In conjunction with the adoption of SFAS No. 133, on January 1, 2001, the Company recorded a derivative loss (net of tax) of $1.5 million as the cumulative effect of a change in accounting principle related to this derivative contract. During the third quarter of 2001, the Company recorded a $625,000 impairment for an outstanding account receivable from a purchaser of the

Company's gas production. In addition, during 2001, the Company entered into certain commodity derivative contracts with Enron North America Corporation (ENAC), a subsidiary of Enron Corporation (Enron). During the fourth quarter of 2001, Enron and ENAC filed for Chapter 11 bankruptcy, and the Company determined that the ENAC contracts no longer qualified for cash flow hedge accounting treatment under SFAS No. 133. Consequently, in 2001 the Company recorded a loss of $328,000 consisting of $82,000 related to oil and gas hedge contracts that had or would have settled in 2001 and $246,000 related to contracts that would have settled in 2002. The amount deferred in accumulated other comprehensive income at December 31, 2001 of $246,000 was reclassified to earnings during 2002 based on the originally scheduled settlement periods of the contracts.

Direct lifting costs incurred by Carbon USA were $1.6 million or $.45 per Mcfe for the year ended December 31, 2002 compared to $1.7 million or $.50 per Mcfe for 2001. The decrease in direct lifting costs was primarily due to a decrease in the number of well workovers and equipment repairs compared to the year ended December 31, 2001.

Other production costs incurred by Carbon USA consisting primarily of severance taxes, gathering and processing fees and production overhead were $3.2 million for the year ended December 31, 2002 compared to $3.0 million for 2001. The increase was primarily due to increased gathering and processing fees and higher severance taxes due to increased oil, liquids and gas production, partially offset by lower oil, liquids and gas prices and a credit for prior period ad valorem taxes.

Direct lifting costs incurred by Carbon Canada were $1.7 million or $.67 per Mcfe for the year ended December 31, 2002 compared to $1.6 million or $.58 per Mcfe for 2001. The higher per Mcfe expense for the year ended December 31, 2002 was primarily due to compression expenses associated with the production of natural gas in Alberta and the effect of fixed operating costs that were not reduced during the voluntary curtailment of production during the third quarter of 2002.

General and administrative expenses incurred by Carbon USA (net of overhead reimbursements on operated wells), increased 4% from $2.8 million for the year ended December 31, 2001 to $2.9 million for 2002. The increase was primarily due to one time legal expenses of $160,000 related to unsuccessful litigation in which the Company was a plaintiff that was concluded in 2002. For the years ending December 31, 2001 and 2002, Carbon USA capitalized $196,000 and $162,000, respectively, of G&A related to geological and geophysical activities.

General and administrative expenses incurred by Carbon Canada (net of overhead reimbursements on operated wells) increased 16% from $1.7 million for the year ended December 31, 2001 to $2.0 million for 2002. The increase was primarily due to salary increases, personnel additions and increased consulting costs in conjunction with the Company's higher level of capital expenditures.

Interest and other expense incurred by Carbon USA increased 23% from $653,000 for the year ended December 31, 2001 to $804,000 for 2002. The increase was due primarily to increased average debt balances during the year ended December 31, 2002 relative to 2001, partially offset by lower borrowing rates.

Interest and other expense incurred by Carbon Canada increased 19% from $210,000 for the year ended December 31, 2001 to $250,000 for 2002. The increase was due primarily to increased average debt balances during the year ended December 31, 2002 relative to 2001, partially offset by lower borrowing rates.

Depreciation, depletion and amortization (DD&A) of oil and gas assets is calculated using the units of production method. DD&A is typically determined by using historical capitalized costs incurred to find, develop and recover oil and gas reserves. However, the Company's DD&A rate has been determined primarily by the purchase price incurred by the Company in its acquisitions of Carbon USA and Carbon Canada, the volume of proved reserves the Company acquired in the acquisitions and a ceiling test impairment recorded by the Company in the second quarter of 2002.

DD&A expense incurred by Carbon USA was $3.6 million or $1.01 per Mcfe for the year ended December 31, 2002 compared to $3.5 million or $1.07 per Mcfe for 2001. The decreased rate is primarily due to the ceiling test impairment recorded by the Company in the second quarter of 2002, partially offset by an increase in the DD&A rate per Mcfe due to the capitalized cost per Mcfe of reserves added in 2001.

DD&A expense incurred by Carbon Canada was $2.5 million or $.99 per Mcfe compared to $2.7 million or $.97 per Mcfe for 2001. The increased rate for the year ended December 31, 2002 compared to 2001 is due to the capitalized cost per Mcfe of reserves added during 2001, partially offset by a ceiling test impairment recorded by the Company in the second quarter of 2002.

The non-cash ceiling test impairment of the Company's full cost pool was recorded because the capitalized cost of its oil and natural gas reserves in the United States and Canada exceeded the ceiling limitation established for those reserves. The United States Securities and Exchange Commission (SEC) requires that public companies utilizing the full cost method of accounting for oil and gas properties perform a ceiling test at the end of each quarterly reporting period. The ceiling test limitation requires that capitalized costs less related accumulated depletion and deferred income taxes may not exceed the sum of the present value of future net revenue from estimated production of proved oil and gas reserves using a 10% discount factor and unescalated oil and gas prices and costs as of the end of the period; plus the cost of properties not being amortized, if any; plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less related income tax effects. Under the SEC guidelines, the natural gas and oil prices used to determine the future value of the Company's oil and gas reserves are based on posted prices on the last day of the reporting period (with consideration of price changes only to the extent provided by contractual arrangements). The SEC allows the use of hedge adjusted prices in the full cost ceiling test and the Company's ceiling test was reflective of that methodology.

At June 30, 2002, the methodology required the Company to use natural gas prices of $1.10 per MMBtu for Colorado and Utah and $1.43 per MMBtu for central Alberta. These prices were $2.32 per MMBtu for Colorado and Utah and $1.99 per MMBtu for Alberta less than the price for natural gas delivered to Henry Hub, the principal reference price for natural gas in the United States. The differential was considerably greater than the 36 month average historical differential at June 30, 2002 of $.37 per MMBtu for Colorado and Utah and $.29 per MMBtu for Alberta. The Company's capitalized costs exceeded the ceiling limitation in the United States and Canada by $14.0 million and $2.4 million, respectively. When product prices were adjusted for oil and natural gas hedges in place at June 30, 2002, the Company's capitalized costs exceeded the ceiling limitation in the United States and Canada by $12.0 million and $1.2 million, respectively. At June 30, 2002, the Company recorded a $12.0 million and $1.2 million non-cash charge in the United States and Canada, respectively, to reflect these impairments. See Note 1 to the Consolidated Financial Statements for additional information.

During the fourth quarter of 2002, natural gas prices received by Carbon for production in Colorado and Utah, where approximately 60% of the Company's domestic production is located, averaged approximately $2.50 per MMBtu, nearly $1.50 per MMBtu less than the price posted for natural gas delivered to Henry Hub. For most of 2002, natural gas prices for production in these areas were low relative to the rest of the producing areas in the United States. Lack of regional seasonal demand and inadequate pipeline transportation capacity necessary to transport natural gas to consuming regions is the principal factor contributing to the large price differentials. The prospect of additional pipeline capacity out of the region is expected to help alleviate the high price differentials received by Carbon and other Rocky Mountain gas producers. Continued volatility is expected to affect the price received for natural gas produced by Carbon in the United States and Canada.

Income tax expense incurred by Carbon USA was $746,000 for the year ended December 31, 2002 compared to $135,000 for 2001. Due primarily to the low commodity prices resulting in the full cost ceiling impairment recorded during the second quarter of 2002, the Company recorded a deferred tax asset valuation allowance of $5.6 million for the year ended December 31, 2002.

Income tax expense incurred by Carbon Canada was $1,000 for the year ended December 31, 2002 compared to $2.0 million for 2001. The decrease in the effective tax rate for the year ended December 31, 2002 was due to permanent differences in the deductibility of Canadian royalties for oil, liquids, and natural gas versus a resource allowance, that was magnified due to the small ($212,000) loss before income taxes for the year ended December 31, 2002.

*RESULTS OF OPERATIONS COMPARISON OF 2001 RESULTS TO 2000*

The following table and the discussion that follows present comparative revenue, sales volumes, average sales prices, expenses and the percentage change between periods for the years ended December 31, 2001 and 2000. The Company's Canadian operations were established in February 2000 through an exchange offer of Carbon shares for shares of Carbon Canada. The results for the Company's Canadian operations for 2000 in the following table are pro forma to reflect the acquisition of Carbon Canada as if it had occurred on January 1, 2000. No other adjustments from reported net income were made in the preparation of this schedule.

| | United States For the Year Ended December 31, | | | Canada For the Year Ended December 31, | | |
|---|---|---|---|---|---|---|
| | **2001** | **2000** | **Change** | **2001** | **2000** | **Change** |
| | (Dollars in thousands, except prices and per Mcfe information) | | | (Dollars in thousands, except prices and per Mcfe information) | | |
| Revenues: | | | | | | |
| Oil and gas revenues | $ 11,455 | $ 12,100 | -5% | $ 11,080 | $ 5,945 | 86% |
| Marketing and other, net | 532 | 245 | 117% | 2 | (70) | n/a |
| Total revenues | 11,987 | 12,345 | -3% | 11,082 | 5,875 | 89% |
| Daily sales volumes: | | | | | | |
| Natural gas (MMcf) | 7.7 | 9.2 | -16% | 6.6 | 4.0 | 65% |
| Oil and liquids (Bbl) | 222 | 190 | 17% | 161 | 122 | 32% |

| | United States For the Year Ended December 31, | | | Canada For the Year Ended December 31, | | |
|---|---|---|---|---|---|---|
| Equivalents production (MMcfe 6:1) | 9.0 | 10.3 | -13% | 7.6 | 4.7 | 62% |
| Average price realized: | | | | | | |
| Natural gas (Mcf) | $ 3.34 | $ 3.11 | 7% | $ 4.05 | $ 3.34 | 21% |
| Oil and liquids (Bbl) | 25.49 | 23.03 | 11% | 21.76 | 23.33 | -7% |
| Direct lifting costs | $ 1,654 | $ 1,602 | 3% | $ 1,612 | $ 873 | 85% |
| Average direct lifting costs/Mcfe | 0.50 | 0.42 | 19% | 0.58 | 0.50 | 16% |
| Other production costs | 3,015 | 3,218 | -6% | 14 | | n/a |
| General and administrative, net | 2,767 | 1,989 | 39% | 1,736 | 1,373 | 26% |
| Depreciation, depletion and amortization | 3,536 | 4,042 | -13% | 2,698 | 1,698 | 59% |
| Interest and other expense, net | 653 | 917 | -29% | 210 | 234 | -10% |
| Income tax provision | 135 | 44 | 207% | 1,956 | 681 | 187% |

Revenues for oil and gas sales of Carbon USA for the year ended December 31, 2001 were $11.5 million, a 5% decrease from 2000. The decrease was due primarily to decreased gas sales and natural production declines in all operating areas partially offset by increased oil production and increased oil and gas prices.

Revenues for oil, liquids and gas sales of Carbon Canada for the year ended December 31, 2001 were $11.1 million, an increase of 86% from 2000. The increase was due primarily to increased oil, liquids and gas production and higher gas prices.

Carbon USA's average production for the year ended December 31, 2001 was 222 barrels of oil per day and 7.7 million cubic feet (MMcf) of gas per day, a decrease of 13% from 2000 on a Mcf equivalent (Mcfe) basis where one barrel of oil is equal to six Mcf of gas. In January 2001, the Company divested its entire working interests and related leasehold rights in the San Juan Basin. Exclusive of this disposition, the Company would have increased its production for the year ended December 31, 2001 compared to 2000 by 4% on an Mcfe basis. The increase in production was due to successful drilling activities conducted during 2001 in the Piceance and Permian Basins, offset by natural production declines in all operating areas. For the year ended December 31, 2001, Carbon USA participated in the drilling of 35 gross (22.3 net) wells of which ten gross (5.0 net) were completed as oil wells, 22 gross (14.8 net) were completed as gas wells and three gross (2.5 net) wells were abandoned as dry holes. For the year ended December 31, 2000, Carbon USA participated in the drilling of 15 gross (6.7 net) wells of which ten gross (2.9 net) were completed as oil wells and five gross (3.8 net) wells were abandoned as dry holes.

Carbon Canada's average production for the year ended December 31, 2001 was 161 barrels of oil and liquids per day and 6.6 MMcf of gas per day, an increase of 62% from 2000 on an Mcfe basis. The increase was due primarily to successful drilling and recompletion activities in the Carbon and Rowley areas of central Alberta. For the year ended December 31, 2001, Carbon Canada participated in the drilling of 11 gross (10.5 net) wells all of which were completed as gas wells. For the year ended December 31, 2000, Carbon Canada participated in the drilling of eight gross (4.9 net) wells all of which were completed as gas wells.

Average oil prices realized by Carbon USA increased 11% from $23.03 per barrel for the year ended December 31, 2000 to $25.49 for 2001. The average oil price includes hedge gains of $25,000 or $.30 per barrel for the year ended December 31, 2001 compared to hedge losses of $414,000 or $5.98 per barrel for 2000. Average natural gas prices realized by Carbon USA increased 7% from $3.11 per Mcf for the year ended December 31, 2000 to $3.34 per Mcf for 2001. The average natural gas price includes hedge losses of $1.5 million or $.53 per Mcf for the year ended December 31, 2001 compared to hedge losses of $2.6 million or $.78 per Mcf for 2000.

Average oil and liquids prices realized by Carbon Canada decreased 7% from $23.33 per barrel for the year ended December 31, 2000 to $21.76 for 2001. The average oil and liquids price includes hedge gains of $33,000 or $.56 per barrel for the year ended December 31, 2001 compared to hedge losses of $186,000 or $3.51 per barrel for 2000. Average natural gas prices realized by Carbon Canada increased 21% from $3.34 per Mcf for the year ended December 31, 2000 to $4.05 for 2001. The average natural gas price includes hedge losses of $571,000 or $.24 per Mcf for the year ended December 31, 2001 compared to hedge losses of $987,000 or $.59 per Mcf for 2000.

Marketing and other revenues for Carbon USA increased 117% from $245,000 for the year ended December 31, 2000 to $532,000 for 2001. Marketing revenue for the year ended December 31, 2001 included mark-to-market gains of $1.2 million related to a derivative contract that did not qualify for hedge accounting treatment under provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." In conjunction with the adoption of SFAS No. 133, on January 1, 2001, the Company recorded a derivative loss (net of tax) of $1.5 million as the cumulative effect of a change in accounting principle related to this derivative contract. During the third quarter of 2001, the Company recorded a $625,000 impairment for an outstanding account receivable from a purchaser of the Company's gas production. In addition, during 2001, the Company entered into certain commodity derivative contracts with Enron North America Corporation (ENAC), a subsidiary of Enron Corporation (Enron). During the fourth quarter of 2001, Enron and ENAC filed for Chapter 11 bankruptcy, and the Company determined that the ENAC contacts no longer qualified for cash flow hedge accounting treatment under SFAS No. 133. Consequently, the Company recorded a loss of $328,000 consisting of $82,000 related to oil and gas hedge contracts that had or would have settled in 2001 and $246,000 related to contracts that would have settled in 2002.

Direct lifting costs incurred by Carbon USA were $1.7 million or $.50 per Mcfe for the year ended December 31, 2001 compared to $1.6 million or $.42 per Mcfe for 2000. The per Mcfe increase was primarily due to well and equipment repairs in the Permian and Piceance Basins performed in 2001.

Other production costs incurred by Carbon USA consisting primarily of severance taxes, gathering and processing fees and production overhead were $3.0 million for the year ended December 31, 2001 compared to $3.2 million for 2000. The decrease was primarily due to lower severance taxes due to declines in gas production.

Direct lifting costs incurred by Carbon Canada were $1.6 million or $.58 per Mcfe for the year ended December 31, 2001 compared to $873,000 or $.50 per Mcfe for 2000. The increase was primarily due to increased compression costs in the Carbon area which contributed to a corresponding increase in gas production.

General and administrative expenses incurred by Carbon USA, net of overhead reimbursements, increased 39% from $2.0 million for the year ended December 31, 2000 to $2.8 million for 2001. The increase was primarily due to a reduction in overhead reimbursements as a result of the sale of the Company's San Juan Basin properties, salary increases, personnel additions and increased consulting costs in conjunction with the Company's higher level of capital expenditures and legal expenses related to the case of Bonneville Fuels Corporation vs. Williams Production RMT Company.

General and administrative expenses incurred by Carbon Canada, net of overhead reimbursements, increased 26% from $1.4 million for the year ended December 31, 2000 to $1.7 million for 2001. The increase was primarily due to salary increases, personnel additions and increased consulting costs in conjunction with the Company's higher level of capital expenditures.

Interest and other expense incurred by Carbon USA decreased 29% from $917,000 for the year ended December 31, 2000 to $653,000 for 2001. The decrease was due primarily to a reduction in average debt balances throughout 2001 as a result of proceeds received from the divestiture of the Company's San Juan Basin properties, decreased margin deposits related to the Company's derivative positions and a decrease in interest rates, partially offset by increased funding requirements for capital expenditures.

Interest and other expense incurred by Carbon Canada decreased 10% from $234,000 for the year ended December 31, 2000 to $210,000 for 2001. The decrease was due primarily to a reduction in debt as a result of increased cash flow from operating activities and a decline in interest rates, partially offset by increased funding requirements for capital expenditures.

Depreciation, depletion and amortization (DD&A) of oil and gas assets is calculated using the units of production method. DD&A is typically determined by using historical capitalized costs incurred to find, develop and recover oil and gas reserves. However, the Company's current DD&A has been determined primarily by the purchase price incurred in its acquisition of Carbon USA and Carbon Canada, and the volume of proved reserves the Company acquired in the acquisitions. For information regarding full cost accounting and DD&A, see Note 1 to the Consolidated Financial Statements.

DD&A expense incurred by Carbon USA decreased 13% from $4.0 million for the year ended December 31, 2000 to $3.5 million for 2001. The decrease was due primarily to decreased production. DD&A was $1.07 per Mcfe for the years ended December 31, 2000 and 2001.

DD&A expense incurred by Carbon Canada increased 59% from $1.7 million for the year ended December 31, 2000 to $2.7 million for 2001. The increase resulted primarily from increased production. DD&A expense was $.98 per Mcfe for the year ended December 31, 2000 compared to $.97 per Mcfe for 2001.

Income tax expense incurred by Carbon USA was $135,000 for the year ended December 31, 2001, an effective rate of 37%. This compares to income tax expense of $44,000 or an effective rate of 8% for 2000. The effective rate in 2000 was the result of a reversal of an income tax valuation allowance of $192,000.

Income tax expense incurred by Carbon Canada was $2.0 million for the year ended December 31, 2001 compared to $681,000 for 2000. The effective rate was 40% for both years.

*LIQUIDITY AND CAPITAL RESOURCES*

At December 31, 2002, the Company had $52.3 million of assets. Total capitalization was $41.3 million, consisting of 45% of stockholders' equity and 55% of debt.

For a discussion of the Company's credit facilities, see Note 3 to the Consolidated Financial Statements in this report.

Net cash provided by operations for the year ended December 31, 2002 was $2.7 million compared to $14.2 million in 2001. Net cash provided by operations prior to changes in working capital for the year ended December 31, 2002 was $5.5 million compared to $8.6 million in 2001. The decrease in operating cash flow in 2002 compared to 2001 was primarily due to declines in oil, liquids and natural gas prices in all areas and voluntary curtailments of production in the third quarter of 2002 because of low gas prices, partially offset by increased oil, liquids and gas production in the United States for 2002.

Net cash provided by operations for the year ended December 31, 2001 was $14.2 million compared to $3.8 million in 2000. Net cash provided by operations prior to changes in working capital for the year ended December 31, 2001 was $8.6 million compared to $7.5 million in 2000. The increase in operating cash flow in 2001 compared to 2000 was primarily due to increased oil, liquids and gas production in Canada, increased oil, liquids and natural gas prices in all areas and decreased working capital requirements, especially a decline in margin deposit requirements for the Company's derivative accounts.

For the year ended December 31, 2002, Carbon USA spent approximately $4.5 million primarily to fund development and exploration activities in Colorado, Montana, New Mexico and Utah. Carbon USA received $3.1 million in proceeds related to the disposition of certain overriding royalty interests in the Piceance and Permian Basin and the sale of working interests and related leasehold rights in New Mexico and Kansas. For the year ended December 31, 2002, Carbon Canada spent approximately $6.1 million primarily to fund development and exploration activities in the Carbon area and for the acquisition of properties in the Rowley area of central Alberta.

For the year ended December 31, 2001, Carbon USA spent approximately $16.6 million primarily to fund development and exploration activities in Colorado, Utah and New Mexico. Carbon USA also received $6.8 million in proceeds related to the disposition of the Company's entire working interest and related leasehold rights in the San Juan Basin. For the year ended December 31, 2001, Carbon Canada spent approximately $6.7 million primarily to fund development activities in the Carbon area of central Alberta.

For the year ended December 31, 2000, Carbon USA spent approximately $4.8 million primarily to fund development and exploration activities in New Mexico. For the year ended December 31, 2000, Carbon Canada spent approximately $3.1 million primarily to fund development activities in the Carbon area of central Alberta.

Carbon's primary cash requirements for 2003, subject to completion of the proposed merger described previously, will be to fund exploration and development expenditures, finance acquisitions, repay debt, and for general working capital needs. At December 31, 2002, the Company had no cash balances as all available cash flow generated from operations was used to pay down the Company's long-term debt. The Company has budgeted capital expenditures for 2003, exclusive of unplanned acquisitions or divestitures, of approximately $21 million. At December 31, 2002, the Company is in compliance with all of its debt covenants and has no reason to believe that either of its credit facilities will require principal payments during the next twelve months. Under the facilities, funds available at December 31, 2002 were approximately $3.3 million. In addition, the new U.S. facility secured on December 31, 2002 with the Bank of Oklahoma National Association (Bank of Oklahoma) will provide the Company with an additional borrowing capability of $1.9 million compared to its current facility, for a total borrowing capacity of $5.2 million.

On March 24, 2003, Carbon USA closed on the sale of its interests in 97 gross (23.3 net) wells and 25,400 gross (8,200 net) acres located primarily in southeastern New Mexico. The sale price was $15.7 million with an effective date of January 1, 2003. The Company will initially use the proceeds from the sale to pay down debt and anticipates utilizing the resulting borrowing capacity to accelerate its 2003 exploration and development drilling program in the Piceance and Uintah Basins. The Company anticipates that there will be some downward modification to its bank borrowing capacity as a result of the sale of properties in March 2003, nevertheless, Carbon believes that available borrowings under its credit agreements, projected operating cash flows and cash received from the March 2003 asset sale will be sufficient to cover its working capital, planned capital expenditures, and debt service requirements for the next 12 months.

The Company's future cash flow is subject to a number of variables, including the level of production, commodity prices and capital expenditures. Also, borrowings under Carbon's credit facilities are subject to a number of conditions, including compliance with various covenants and borrowing base calculations. As a result, there can be no assurance that the operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures or to meet the other cash needs.

The table below sets forth the Company's contractual obligations at December 31, 2002 and the effect such obligations are expected to have on its liquidity and cash flow in future periods (in thousands):

| | **Payments Due By Period** | | |
|---|---|---|---|
| **Contractual Obligations** | **Less than 1 Year** | **1-3 Years** | **4-5 Years** |

| | Payments Due By Period | | |
|---|---|---|---|
| Revolving credit facility | $ | $ 22,709 | $ |
| Operating leases | 435 | 303 | |
| Transporation agreements | 113 | 107 | |
| | $ 548 | $ 23,119 | $ |

Contractual obligations for the Company's revolving credit facilities are presented prior to the March 24, 2003 sale of Carbon USA's interests in southeastern New Mexico for $15.7 million.

*DISCLOSURES REGARDING FORWARD-LOOKING STATEMENTS*

This Annual Report on Form 10-K includes "forward-looking statements". All statements other than statements of historical facts included in the Annual Report on Form 10-K are forward-looking statements. Such statements address activities, events or developments that the Company expects, believes, projects, intends or anticipates will or may occur, including such matters as future capital, development and exploration expenditures, reserve estimates (including estimates of future net revenues associated with such reserves and the present value of such future net revenues), future production of oil and natural gas, business strategies, expansion and growth of the Company's operations, cash flow and anticipated liquidity, prospect development and property acquisition, obtaining financial or industry partners for prospect or program development, or marketing of oil and natural gas. Although the Company believes that the expectations reflected in the forward-looking statements and the assumptions upon which such forward-looking statements are based are reasonable, it can give no assurance that such expectations and assumptions will prove to be correct. Factors that could cause actual results to differ materially ("Cautionary Statements") are described, in among other places in the Marketing, Competition, and Government Regulation sections in this Form 10-K and under "Management's Discussion and Analysis of Financial Condition and Results of Operations." These factors include, but are not limited to general economic conditions, the market price of oil and natural gas, the risks associated with exploration, the Company's ability to find, acquire, market, develop and produce new properties, operating hazards attendant to the oil and natural gas business, uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures, the strength and financial resources of the Company's competitors, the Company's ability to find and retain skilled personnel, climatic conditions, labor relations, availability and cost of material and equipment, environmental risks, the results of financing efforts, and regulatory developments. All written and oral forward-looking statements attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by the Cautionary Statements. The Company undertakes no obligation to update any forward-looking statements to reflect future events or developments.

*CRITICAL ACCOUNTING POLICES*

The following summarizes several of our critical accounting policies. See a complete list of significant accounting policies in Note 1 to the Consolidated Financial Statements.

*Property and Equipment* The Company follows the full cost method of accounting for its oil and gas properties, whereby all costs incurred in the acquisition, exploration and development of properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes and direct overhead related to exploration and development activities) are capitalized.

Capitalized costs are accumulated for the United States and Canada as separate cost centers and are depleted using the units of production method based on proved reserves of oil and gas. For purposes of the depletion calculation, oil and gas reserves are converted to an equivalent unit of measure where six thousand cubic feet of gas is equal to one barrel of oil. The estimated future cost of site restoration, dismantlement and abandonment activities is provided for as a component of depletion. Investments in unproved properties are recorded at the lower of cost or fair market value and are not depleted pending the determination of the existence of proved reserves.

Pursuant to full cost accounting rules, capitalized costs less related accumulated depletion and deferred income taxes may not exceed the sum of the present value of future net revenue from estimated production of proved oil and gas reserves using a 10% discount factor and unescalated oil and gas prices and costs as of the end of the period; plus the cost of properties not being amortized, if any; plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less related income tax effects.

A non-cash ceiling test impairment of the Company's full cost pool was recorded in the second quarter of 2002 because the capitalized cost of its oil and natural gas reserves in the United States and Canada exceeded the ceiling limitation established for those reserves. The SEC requires that public companies utilizing the full cost method of accounting for oil and gas properties perform a ceiling test at the end of each quarterly reporting period. Under the SEC guidelines, the natural gas and oil prices used to determine the future value of the Company's oil and gas reserves are based on posted prices on the last day of the reporting period (with consideration of price changes only to the extent provided by contractual arrangements).

Should natural gas and crude oil prices decline in the future, even if only for a brief period of time, it is possible that additional impairments of oil and gas properties could occur.

Proceeds from disposal of interests in oil and gas properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustment would significantly alter the rate of depletion.

*Derivative Instrument and Hedging Activities* Pursuant to Company guidelines, the Company utilizes derivative instruments only as a hedging mechanism and does not enter into speculative transactions. The Company has a Risk Management Committee to administer and approve all hedging transactions. Gains or losses from financial instruments that qualify for hedge accounting treatment are recognized as an adjustment to sales revenue in the period in which the financial instrument matures. Gains or losses from financial instruments that do not qualify for hedge accounting treatment are recognized currently as marketing and other revenue, net. The cash flows from such agreements are included in operating activities in the consolidated statements of cash flows.

The estimation of fair values for the Company's hedging derivatives requires substantial judgment. The fair values of the Company's derivatives are estimated on a monthly basis using an option-pricing model. The option-pricing model uses various factors that include closing exchange prices, volatility and the time value of options. The estimated future prices are compared to the prices fixed by the hedge agreements, and the resulting estimated future cash inflows (outflows) over the lives of the hedges are discounted. These pricing and discounting variables are sensitive to market volatility as well as to changes in future price forecasts, regional price differentials and interest rates.

*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 realizability of deferred tax assets, management 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. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment.

## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

*INTEREST RATE RISK*

Because of its debt position, the Company is exposed to interest rate risk on the unhedged portion of its debt. Interest rate risk is estimated as the potential change in the fair value of interest sensitive investments resulting from an immediate hypothetical change in interest rates. The sensitivity analysis presents the change in fair value of these instruments and changes in the Company's earnings and cash flows assuming an immediate one percent change in floating interest rates. At December 31, 2002, the Company had $16.4 million of floating rate debt through its facility with Wells Fargo and $6.3 million through its facility with CIBC. The Company currently has interest rate swap agreements that effectively convert a portion of its variable rate borrowings to fixed rate debt as described in Note 9 to the Consolidated Financial Statements in this report. Assuming constant debt levels, the impact on earnings and cash flow for the twelve month period beginning January 1, 2003, from a one percent change in interest rates would be approximately $157,000 before taxes.

*FOREIGN CURRENCY RISK*

The Canadian dollar is the functional currency of Carbon Canada. The Company is subject to foreign currency exchange rate risk on cash flows relating to sales, expenses, financing and investing transactions. The Company has not entered into foreign currency forward contracts or other similar financial instruments to manage this risk.

*COMMODITY PRICE RISK*

Oil and gas commodity markets are influenced by global and regional supply and demand factors. Worldwide political events can also impact commodity prices. The prices received by Carbon for its natural gas production are determined mainly by factors affecting North American regional supply and demand for natural gas. Based upon recent reportable events, it is possible that published indices used to establish the price received for the Company's natural gas production may not be an accurate indication of the market price for natural gas.

At December 31, 2002, approximately 60% of the Company's United States production is in Colorado and Utah. After March 2002, natural gas prices for production in these areas were unusually low relative to the rest of the producing areas in the United States. Lack of regional seasonal demand and inadequate pipeline transportation capacity necessary to transport natural gas to consuming regions are principal factors contributing to the large price differentials. The prospect of additional pipeline capacity out of the region is expected to help alleviate the high price differentials received by Carbon and other Rocky Mountain gas producers. However, continued volatility is expected to affect the price received for natural gas produced by Carbon in the United States and Canada.

The Company may use certain financial instruments including swaps, collars, futures and other contracts in an attempt to reduce exposure to fluctuations in the price of oil and natural gas by establishing fixed prices or hedges for its natural gas production. Hedging the Company's oil and natural gas production may limit the Company's exposure to price declines or limit the benefit of price increases. Risks associated with the practice of hedging include counterparty credit risk, Carbon's inability to deliver required physical volumes of gas which support the Company's hedges, inefficient or non-correlatable hedges, basis risk, inability to liquidate hedge positions if desired and other unforeseen economic factors.

The table below sets forth the Company's derivative financial instrument positions related to its natural gas and oil production at December 31, 2002:

Swaps:

| Carbon USA Contracts | | | | Carbon Canada Contracts | | | |
|---|---|---|---|---|---|---|---|
| **Time Period** | **Bbl/ MMBtu** | **Weighted Average Fixed Price Bbl/MMBtu** | **Derivative Asset/ (Liability)** | **Time Period** | **Bbl/ MMBtu** | **Weighted Average Fixed Price Bbl/MMBtu** | **Derivative Asset/(Liability)** |
| | | | **(thousands)** | | | | **(thousands)** |
| **Gas** | | | | **Gas** | | | |
| 01/01/03-12/31/03 | 1,400,000 | $ 3.07 | $ (541) | 01/01/03-12/31/03 | 216,000 | $ 2.83 | $ (242) |
| **Oil** | | | | **Oil** | | | |
| 01/01/03-12/31/03 | 46,000 | $ 25.42 | $ (76) | 01/01/03-12/31/03 | 37,000 | $ 25.47 | $ (57) |

The Company periodically enters into long-term physical contracts for a portion of its natural gas and oil production. The table below sets forth fixed price sales contracts at December 31, 2002:

Fixed price contracts:

| Carbon USA Contracts | | | Carbon Canada Contracts | | |
|---|---|---|---|---|---|
| **Time Period** | **MMBtu** | **Weighted Average Fixed Price MMBtu** | **Time Period** | **MMBtu** | **Weighted Average Fixed Price MMBtu** |
| **Gas** | | | **Gas** | | |
| 01/01/03-03/31/03 | 180,000 | 2.57 | 01/01/03-12/31/03 | 778,000 | $ 3.16 |

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

**Carbon Energy Corporation**

**Consolidated Financial Statements**

### INDEX TO FINANCIAL STATEMENTS

**INDEPENDENT AUDITORS' REPORT**

The Board of Directors and Stockholders
Carbon Energy Corporation

We have audited the 2002 consolidated financial statements of Carbon Energy Corporation (a Colorado corporation) and subsidiaries as listed in the accompanying index. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit. The 2001 and 2000 consolidated financial statements of Carbon Energy Corporation and subsidiaries as listed in the accompanying index were audited by other auditors who have ceased operations. Those auditors' report dated March 22, 2002, on those consolidated financial statements was unqualified and included an explanatory paragraph that described the change in the Company's method of accounting for derivative instruments and hedging activities discussed in Note 1 to the consolidated financial statements.

We conducted our audit 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 audit provides a reasonable basis for our opinion.

In our opinion, the 2002 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Carbon Energy Corporation and subsidiaries as of December 31, 2002, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for derivative instruments and hedging activities in 2001.

KPMG LLP

Denver, Colorado
March 21, 2003, except as to the seventh paragraph under "Recent Accounting Pronouncements" of
Note 1, which is as of August 22, 2003

**REPORT OF INDENDENT PUBLIC ACCOUNTANTS**

THE FOLLOWING REPORT IS A COPY OF THE PREVIOUSLY ISSUED REPORT FROM ARTHUR ANDERSEN LLP (ANDERSEN). ANDERSEN DID NOT PERFORM ANY PROCEDURES IN CONNECTION WITH THIS ANNUAL REPORT ON FORM 10-K. ACCORDINGLY, THIS REPORT HAS NOT BEEN REISSUED BY ANDERSEN.

To Carbon Energy Corporation:

We have audited the accompanying consolidated balance sheets of Carbon Energy Corporation (a Colorado corporation) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of operations, stockholders' equity and cash flows for the years ended

December 31, 2001 and 2000 and the period from inception (September 14, 1999) through December 31, 1999. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Carbon Energy Corporation and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for the years ended December 31, 2001 and 2000 and the period from inception (September 14, 1999) through December 31, 1999, in conformity with accounting principles generally accepted in the United States.

As explained in Note 1 to the consolidated financial statements, on January 1, 2001, the Company changed its method of accounting for derivative instruments and hedging activity.

ARTHUR ANDERSEN LLP

Denver, Colorado
March 22, 2002

**CARBON ENERGY CORPORATION**

**CONSOLIDATED BALANCE SHEETS**

**(in thousands)**

| | December 31, | |
|---|---|---|
| | **2002** | **2001** |
| ***ASSETS*** | | |
| Current assets: | | |
| Cash | $ | $ |
| Accounts receivable, trade | 3,240 | 2,311 |
| Prepaid expenses and other | 918 | 317 |
| Current derivative asset | | 341 |
| Total current assets | 4,158 | 2,969 |
| Property and equipment, at cost: | | |
| Oil and gas properties, using the full cost method of accounting: | | |
| Unproved properties | 7,080 | 7,500 |
| Proved properties | 71,223 | 62,750 |
| Furniture and equipment | 894 | 927 |
| | 79,197 | 71,177 |
| Less accumulated depreciation, depletion and amortization | (31,503) | (12,226) |
| Property and equipment, net | 47,694 | 58,951 |
| Deposits and other long-term assets | 452 | 448 |

| | December 31, | |
|---|---|---|
| Total assets | $ 52,304 | $ 62,368 |
| ***LIABILITIES AND STOCKHOLDERS' EQUITY*** | | |
| Current liabilities: | | |
| Accounts payable and accrued expenses | $ 4,914 | $ 5,113 |
| Accrued production taxes payable | 337 | 527 |
| Income taxes payable | | 1,168 |
| Undistributed revenue and other | 1,462 | 1,062 |
| Current derivative liability | 1,116 | 76 |
| Deferred income taxes | | 74 |
| Total current liabilities | 7,829 | 8,020 |
| Long-term debt | 22,709 | 17,870 |
| Other long-term liabilities | 37 | 18 |
| Deferred income taxes | 3,093 | 2,577 |
| Minority interest | 28 | 29 |
| Stockholders' equity: | | |
| Preferred stock, no par value: 10,000,000 shares authorized, none outstanding | | |
| Common stock, no par value: 20,000,000 shares authorized, issued and outstanding 6,116,295 shares and 6,079,225 shares at December 31, 2002 and December 31, 2001, respectively | 31,987 | 31,799 |
| Retained earnings (accumulated deficit) | (12,017) | 2,538 |
| Accumulated other comprehensive loss | (1,362) | (483) |
| Total stockholders' equity | 18,608 | 33,854 |
| Total liabilities and stockholders' equity | $ 52,304 | $ 62,368 |

The accompanying notes are an integral part of these consolidated financial statements.

**CARBON ENERGY CORPORATION**

**CONSOLIDATED STATEMENTS OF OPERATIONS**

**(in thousands, except per share data)**

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | **2002** | **2001** | **2000** |
| Revenues: | | | |
| Oil and gas sales | $ 17,727 | $ 22,535 | $ 17,474 |
| Marketing and other, net | 344 | 534 | 175 |
| | 18,071 | 23,069 | 17,649 |
| Expenses: | | | |
| Oil and gas production costs | 6,578 | 6,295 | 5,613 |

| | For the Year Ended December 31, | | |
|---|---|---|---|
| Depreciation, depletion and amortization | 6,142 | 6,234 | 5,536 |
| Full cost ceiling impairment | 13,218 | | |
| General and administrative, net | 4,887 | 4,503 | 3,249 |
| Interest and other, net | 1,054 | 863 | 1,128 |
| Total operating expenses | 31,879 | 17,895 | 15,526 |
| Income (loss) before income taxes | (13,808) | 5,174 | 2,123 |
| Income tax provision: | | | |
| Current | 13 | 1,518 | 250 |
| Deferred | 734 | 573 | 417 |
| Total taxes | 747 | 2,091 | 667 |
| Income (loss) before cumulative effect of change in accounting principle | (14,555) | 3,083 | 1,456 |
| Cumulative effect of change in accounting principle, net of tax | | (1,510) | |
| Net income (loss) | $ (14,555) | $ 1,573 | $ 1,456 |
| Average number of common shares outstanding: | | | |
| Basic | 6,101 | 6,055 | 5,822 |
| Diluted | 6,101 | 6,294 | 5,874 |
| Earnings (loss) per share basic: | | | |
| Income (loss) before cumulative effect of change in accounting principle | $ (2.39) | $ 0.51 | $ 0.25 |
| Cumulative effect of change in accounting principle, net of tax | | (0.25) | |
| | $ (2.39) | $ 0.26 | $ 0.25 |
| Earnings (loss) per share diluted: | | | |
| Income (loss) before cumulative effect of change in accounting principle | $ (2.39) | $ 0.49 | $ 0.25 |
| Cumulative effect of change in accounting principle, net of tax | | (0.24) | |
| | $ (2.39) | $ 0.25 | $ 0.25 |

The accompanying notes are an integral part of these consolidated financial statements.

**CARBON ENERGY CORPORATION**

**CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY**

**For the Years Ended December 31, 2002, 2001 and 2000**

**(in thousands)**

| | Common Stock | | Retained Earnings (Accumulated Deficit) | Accumulated Other Comprehensive Income (Loss) | Total |
|---|---|---|---|---|---|
| | Shares | Amount | | | |
| Balances, December 31, 1999 | 4,510 | $ 24,806 | $ (491) | $ | $ 24,315 |

| | Common Stock | | Retained Earnings (Accumulated Deficit) | Accumulated Other Comprehensive Income (Loss) | |
|---|---|---|---|---|---|
| Comprehensive income: | | | | | |
| Net income | | | 1,456 | | 1,456 |
| Currency translation adjustment | | | | (225) | (225) |
| Total comprehensive income | | | | | 1,231 |
| Common stock issued | 10 | 55 | | | 55 |
| Common stock issued for acquisition of Carbon Energy Canada | 1,483 | 6,518 | | | 6,518 |
| Issuance of restricted stock grants | 28 | 163 | | | 116 |
| Amortization of restricted stock grants | (9) | (47) | | | |
| Balances, December 31, 2000 | 6,022 | 31,495 | 965 | (225) | 32,235 |
| Comprehensive income: | | | | | |
| Net income | | | 1,573 | | 1,573 |
| Cumulative effect of change in accounting principle, net of tax | | | | (2,768) | (2,768) |
| Currency translation adjustment | | | | (526) | (526) |
| Settled contracts reclassified to income | | | | 1,890 | 1,890 |
| Changes in fair value of outstanding hedge positions | | | | 1,146 | 1,146 |
| Total comprehensive income | | | | | 1,315 |
| Common stock issued | 35 | 175 | | | 175 |
| Amortization of restricted stock grants | 22 | 129 | | | 129 |
| Balances, December 31, 2001 | 6,079 | 31,799 | 2,538 | (483) | 33,854 |
| Comprehensive income: | | | | | |
| Net loss | | | (14,555) | | (14,555) |
| Currency translation adjustment | | | | 116 | 116 |
| Settled contracts reclassified to income | | | | (278) | (278) |
| Changes in fair value of outstanding hedge positions | | | | (717) | (717) |
| Total comprehensive loss | | | | | (15,434) |
| Common stock issued | 13 | 39 | | | 39 |
| Issuance of restricted stock grants | 18 | 140 | | | 149 |
| Amortization of restricted stock grants | 6 | 9 | | | |
| Balances, December 31, 2002 | 6,116 | $ 31,987 | $ (12,017) | $ (1,362) | $ 18,608 |

The accompanying notes are an integral part of these consolidated financial statements.

**CARBON ENERGY CORPORATION**

**CONSOLIDATED STATEMENTS OF CASH FLOWS**

**(in thousands)**

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2002 | 2001 | 2000 |
| Cash flows from operating activities: | | | |
| Net income (loss) | $ (14,555) | $ 1,573 | $ 1,456 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | | |
| Depreciation, depletion and amortization | 6,142 | 6,234 | 5,536 |
| Full cost ceiling impairment | 13,218 | | |
| Non-cash setttlement of derivative contracts | (246) | (1,437) | |
| Deferred income taxes | 734 | 573 | 417 |
| Vesting of restricted stock grants and other | 157 | 156 | 140 |
| Cumulative effect of change in accounting principle | | 1,510 | |
| Changes in operating assets and liabilities: | | | |
| Decrease (increase) in: | | | |
| Accounts receivable | (824) | 4,695 | (3,063) |
| Amounts due from broker | | 3,871 | (2,621) |
| Prepaid expenses and other assets | (109) | 1,018 | 315 |
| Increase (decrease) in: | | | |
| Accounts payable and accrued expenses | (2,263) | (2,150) | 496 |
| Undistributed revenue | 403 | (454) | 1,079 |
| Derivative liabilities | | (1,357) | |
| Net cash provided by operating activities | 2,657 | 14,232 | 3,755 |
| Cash flows from investing activities: | | | |
| Capital expenditures for oil and gas properties | (10,604) | (23,324) | (7,941) |
| Proceeds from property sales | 3,070 | 6,758 | |
| Acquisition of Carbon Energy Canada | | (203) | (146) |
| Capital expenditures for support equipment | (38) | (528) | (179) |
| Net cash used in investing activities | (7,572) | (17,297) | (8,266) |
| Cash flows from financing activities: | | | |
| Proceeds from note payable | 27,028 | 47,833 | 30,852 |
| Principal payments on note payable | (22,192) | (44,919) | (27,381) |
| Proceeds from issuance of common stock | 39 | 175 | 55 |
| Net cash provided by financing activities | 4,875 | 3,089 | 3,526 |
| Effect of exchange rate changes on cash | 40 | (45) | 11 |
| Net (decrease) in cash | | (21) | (974) |
| Cash, beginning of period | | 21 | 995 |
| Cash, end of period | $ | $ | $ 21 |
| Supplemental cash flow information: | | | |
| Cash paid for interest | $ 1,009 | $ 889 | $ 1,147 |

| | For the Year Ended December 31, | | |
|---|---|---|---|
| Cash paid for taxes | 1,340 | 531 | 46 |

The accompanying notes are an integral part of these consolidated financial statements.

**CARBON ENERGY CORPORATION**

**NOTES CONSOLIDATED FINANCIAL STATEMENTS**

**1. Nature of Operations and Significant Accounting Policies**

*Nature of Operations* Carbon Energy Corporation (Carbon) was incorporated in September 1999 under the laws of the State of Colorado to facilitate the acquisition of Bonneville Fuels Corporation (Carbon USA) and subsidiaries. The acquisition of Carbon USA closed on October 29, 1999 and was accounted for as a purchase. In February 2000, Carbon completed an offer to exchange common shares of Carbon for common shares of CEC Resources, Ltd. (Carbon Canada), an Alberta, Canada company. Over 97% of the shareholders of Carbon Canada accepted the offer for exchange. This acquisition closed on February 17, 2000 and was also accounted for as a purchase. In November 2000, Carbon Canada initiated an offer to purchase shares of Carbon Canada stock that were not owned by Carbon. The offer was completed in February 2001 with the acquisition of approximately 34,000 of the 39,000 shares of Carbon Canada stock that were not owned by Carbon. In October 2002, Carbon Canada amended its articles to consolidate its issued and outstanding common shares on a one-for-2,500 basis. In November 2002, Carbon Canada initiated the exchange of common shares for post-consolidation shares or a cash payment in lieu of fractional post-consolidated shares. The exchange was completed in January 2003. After the completion of the exchange, Carbon owns 100% of the stock of Carbon Canada. Collectively, Carbon, Carbon USA, Carbon Canada and its subsidiaries are referred to as the Company. The Company's operations as of December 31, 2002, consist of the acquisition, exploration, development, and production of oil and natural gas properties located primarily in Colorado, Kansas, New Mexico, Texas, Utah, and the Canadian provinces of Alberta and Saskatchewan.

All amounts are presented in U.S. dollars unless otherwise noted.

*Principles of Consolidation* The consolidated financial statements include the accounts of Carbon and its subsidiaries all of which are wholly owned, except Carbon Canada of which the Company owned approximately 99.7% at December 31, 2002. All significant intercompany transactions and balances have been eliminated.

*Cash Equivalents* The Company considers all highly liquid instruments with original maturities of three months or less when purchased to be cash equivalents.

*Property and Equipment* The Company follows the full cost method of accounting for its oil and gas properties, whereby all costs incurred in the acquisition, exploration and development of properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes and direct overhead related to exploration and development activities) are capitalized.

Capitalized costs are accumulated for the United States and Canada as separate cost centers and are depleted using the units of production method based on proved reserves of oil and gas. For purposes of the depletion calculation, oil and gas reserves are converted to an equivalent unit of measure where six thousand cubic feet of gas is equal to one barrel of oil. The estimated future cost of site restoration, dismantlement and abandonment activities is provided for as a component of depletion. For the years ended December 31, 2002, 2001 and 2000, the Company recorded depletion expense per Mcfe of $.97, $1.03 and $1.04, respectively, for activities in the United States and $.99, $.97 and $.96, respectively, for activities in Canada. Investments in unproved properties are recorded at the lower of cost or fair market value and are not depleted pending the determination of the existence of proved reserves.

Pursuant to full cost accounting rules, capitalized costs less related accumulated depletion and deferred income taxes may not exceed the sum of the present value of future net revenue from estimated production of proved oil and gas reserves using a 10% discount factor and unescalated oil and gas prices as of the end of the period; plus the cost of properties not being amortized, if any; plus the lower of cost or estimated fair market value of unproved properties included in the costs being amortized, if any; less related income tax effects.

At June 30, 2002, the Company's capitalized costs exceeded the ceiling limitation in the United States and Canada by $14.0 million and $2.4 million, respectively. When pricing at June 30, 2002 was adjusted for oil and natural gas hedges in place at June 30, 2002, the Company's capitalized costs exceeded the ceiling limitation in the United States and Canada by $12.0 million and $1.2 million, respectively. At June 30, 2002, the Company recorded a $12.0 million and $1.2 million non-cash charge in the United States and Canada, respectively, to reflect the impairments. The impairments were included as additional accumulated depreciation, depletion and amortization (DD&A) in the accompanying balance sheet. At December 31, 2002, the costs reflected in the accompanying financial statements did not exceed the ceiling limitation in either the United States or Canada. Should natural gas and oil prices decline in the future, it is possible that additional impairments of the Company's oil and gas properties could occur.

Proceeds from disposal of interests in oil and gas properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustment would significantly alter the rate of depletion.

Buildings, transportation and other equipment are depreciated on the straight-line method with lives ranging from 3 to 7 years.

*Undistributed Revenue* Represents amounts due to third parties of jointly owned oil and gas properties.

*Revenue Recognition* The Company follows the sales method of accounting for natural gas revenues. Under this method, revenues are recognized based on actual volumes of gas sold to purchasers. To the extent the volumes of gas sold are more (over produced) or less (under produced) than the volumes to which the Company is entitled based on its interests in its properties, a gas imbalance is created. If the estimated remaining reserves of a property will not be sufficient to enable the underproduced owner to recoup its share of production, revenue is deferred and a liability is created.

*Transportation Costs* Gathering and transportation costs incurred by the Company are included as components of oil and gas production costs in the accompanying statements of operations. Under the Company's sales contracts for the years ended December 31, 2002, 2001 and 2000, purchasers assumed all obligations under transportation agreements. As a result, the Company did not incur any transportation costs in those years and reported its gas revenues net of transportation costs incurred by purchasers of its natural gas.

*Income Taxes* The Company accounts for income taxes under the liability method which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements or tax returns. Under this method, deferred tax assets and liabilities are determined based on the difference between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse.

*Derivative Instruments and Hedging Activities* On January 1, 2001, the Company adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," which provides accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet at fair value as either an asset or liability. It also requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

*Foreign Currency Translation* Foreign currency transactions and financial statements are translated in accordance with SFAS No. 52, "Foreign Currency Translation." The Company uses the U.S. dollar as the functional currency for its U.S. operations and the Canadian dollar as the functional currency for its Canadian operations. Assets and liabilities related to the Company's Canadian operations are generally translated at the current exchange rate in effect as of the date of the balance sheet. Translation adjustments are reported as a component of stockholders' equity. Income statement accounts are translated at the average exchange rates during the reporting period. As a result of the change in the value of the Canadian dollar relative to the US dollar, the Company reported non-cash currency translation gains/(losses) of $116,000 and $(526,000) for the years ended December 31, 2002 and 2001, respectively.

*Comprehensive Income* The Company follows the provisions of SFAS No. 130, "Reporting Comprehensive Income." Comprehensive income includes net income and certain items recorded directly to stockholders' equity and classified as other comprehensive income. The components of other accumulated comprehensive income for the years ended December 31, 2002, 2001 and 2000 are as follows:

| | Before-Tax Amount | Tax Expense or Benefit | After-Tax Amount |
|---|---|---|---|
| | | (in thousands) | |
| Balances, December 31, 1999 | $ | $ | $ |
| Currency translation adjustment | (225) | | (225) |
| Balances, December 31, 2000 | (225) | | (225) |
| Cumulative effect of change in accounting principle | (4,665) | 1,897 | (2,768) |
| Currency translation adjustment | (526) | | (526) |

| | Before-Tax Amount | Tax Expense or Benefit | After-Tax Amount |
|---|---|---|---|
| Settled contracts reclassified to income | 3,160 | (1,270) | 1,890 |
| Changes in fair value of outstanding hedge positions | 1,998 | (852) | 1,146 |
| Balances, December 31, 2001 | (258) | (225) | (483) |
| Currency translation adjustment | 116 | | 116 |
| Settled contracts reclassified to income | (442) | 164 | (278) |
| Changes in fair value of outstanding hedge positions | (1,205) | 488 | (717) |
| Balances, December 31, 2002 | $ (1,789) | $ 427 | $ (1,362) |

*Stock-Based Compensation* The Company applies APB Opinion (APB) No. 25 "Accounting for Stock Issued to Employees" and related interpretations in accounting for its employee stock options. Under APB No. 25, compensation expense is recognized for the difference between the option price and market value on the measurement date. No compensation expense was recognized for the years ended December 31, 2002, 2001 and 2000 as the exercise price of the stock options granted under the plan equaled the market price of the underlying stock on the date of grant.

The Company applies SFAS No. 123 "Accounting for Stock-Based Compensation," and related literature in accounting for stock-based awards granted to non-employees other than directors. Under SFAS No. 123, stock-based awards granted to non-employees other than directors are recorded at fair value and recognized in the period(s) in which goods and/or services are received from the non-employee. To date, the Company has never granted stock-based awards to non-employees other than directors.

If compensation costs for stock options granted to employees under this plan had been determined consistent with SFAS No. 123, the Company's net income (loss) and income (loss) per share would have been as follows:

| | Years Ended Decmber 31, | | |
|---|---|---|---|
| | 2002 | 2001 | 2000 |
| | (in thousands except per share data) | | |
| Net income (loss): | | | |
| As reported | $ (14,555) | $ 1,573 | $ 1,456 |
| Less compensation expense, net of tax | 167 | 211 | 180 |
| Pro forma | $ (14,722) | $ 1,362 | $ 1,276 |
| Basic Earnings per common share: | | | |
| As reported | $ (2.39) | $ 0.26 | $ 0.25 |
| Less compensation expense, net of tax | .03 | 0.04 | 0.03 |
| Pro forma | $ (2.42) | $ 0.22 | $ 0.22 |
| Diluted Earnings per common share: | | | |
| As reported | $ (2.39) | $ 0.25 | $ 0.25 |
| Less compensation expense, net of tax | .03 | 0.03 | 0.03 |
| Pro forma | $ (2.42) | $ 0.22 | $ 0.22 |

| | Years Ended Decmber 31, | | |
|---|---|---|---|
| | | | |

See Note 5 for additional information on the Company's stock-based compensation plans.

*Earnings (Loss) Per Share* The Company uses the weighted average number of shares outstanding to calculate earnings per share data. When dilutive, options are included as share equivalents using the treasury stock method and are included in the calculation of diluted per share data. Due to the Company's net loss for the year ended December 31, 2002, basic and diluted per share earnings are the same, as all potentially dilutive securities would be anti-dilutive.

*Accounting Estimates* The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in these financial statements and the accompanying notes. The actual results could differ from those estimates.

*Recent Accounting Pronouncements* In July 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," which requires that the fair value of a liability for an asset retirement obligation 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 asset retirement liability will be accreted to operating expense by using a systematic and rational method. The statement is effective for the Company on January 1, 2003. Upon adoption of the statement, the Company currently expects to record an asset retirement obligation of approximately $3.0 million, an addition to oil and gas properties of approximately $2.4 and a charge of approximately $327,000 (net of tax) for the cumulative effect of a change in accounting principle.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," which provides a single accounting model for long-lived assets to be disposed of and changes the criteria that would have to be met to classify an asset as held-for-sale. The statement also requires expected future operating losses from discontinued operations to be recognized in the periods in which the losses are incurred, which is a change from the current requirement of recognizing such operating losses as of the measurement date. The statement is effective for fiscal years beginning after December 15, 2001. The adoption of SFAS No. 144 did not have a material effect on the Company's financial position or results of operations.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections." SFAS No. 145 is effective for fiscal years beginning after May 15, 2002. The Company adopted this standard early and it had no effect on the Company's results of operations or financial position.

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

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation Transition and Disclosure an amendment of SFAS No. 123." SFAS No. 148 amends SFAS No. 123 to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirement of SFAS No. 123 to require disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on the reported results. SFAS No. 148 is effective for the Company's year ended December 31, 2002 and for interim financial statements commencing in 2003. The Company's adoption of this pronouncement had no impact on its financial condition or results of operations.

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 acquired goodwill 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 the Company'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 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, the Company has included the costs of 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 associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, the Company would be required to reclassify approximately $2.5 million and $1.0 million at December 31, 2002 and December 31, 2001, respectively, out of oil and gas properties and into a separate intangible assets line item. The Company'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. Further, the Company does not believe the classification of the costs of mineral rights associated with extracting oil and gas as intangible assets would have any impact on the Company's compliance with covenants under its debt agreements.

## 2. Acquisition and Disposition of Assets

*Acquisition of Carbon Canada* On February 17, 2000, Carbon completed the acquisition of approximately 97% of the stock of Carbon Canada. An offer to exchange shares of Carbon stock for shares of Carbon Canada stock resulted in the issuance of 1,482,826 shares of Carbon stock to holders of Carbon Canada stock. The acquisition was accounted for as a purchase. In February 2001, Carbon Canada acquired approximately 34,000 of the 39,000 remaining shares of Carbon Canada stock that were not owned by Carbon. At December 31, 2002, Carbon owned 99.7% of the stock of Carbon Canada, and subsequent to year end acquired the remainder of the stock it did not previously own. The following unaudited pro forma information presents a summary of the consolidated results of operations as if the acquisition had occurred at January 1, 2000:

| | For the Year Ended December 31, 2000 | |
|---|---|---|
| | (in thousands, except per share data) | |
| Total revenue | $ | 17,174 |
| Net income | $ | 1,549 |
| Earnings per share: Basic and diluted | $ | 0.26 |

These unaudited pro forma results have been prepared for comparative purposes only and do not purport to be indicative of results of operations that actually would have resulted had the combination occurred at January 1, 2000, or future results of operations of the consolidated entities.

*Disposition of Oil and Gas Assets* In January 2001, the Company closed the sale of its entire working interests and related leasehold rights in the San Juan Basin, receiving net proceeds of approximately $6.8 million. Proceeds from the sale were credited directly to the full cost pool and no gain or loss was recognized. The proceeds were used to repay amounts outstanding under the Company's credit facilities and to finance the Company's exploration and development program.

In July 2002, the Company sold certain overriding royalty interests in the Piceance and Permian Basins, receiving net proceeds of approximately $700,000. Proceeds from the sale were credited directly to the full cost pool and no gain or loss was recognized. The proceeds were used to repay amounts outstanding under the Company's credit facilities.

In September 2002, the Company sold its working interests and related leasehold rights in Kansas, receiving net proceeds of approximately $2.1 million. Proceeds from the sale were credited directly to the full cost pool and no gain or loss was recognized. The proceeds were used to repay amounts outstanding under the Company's credit facilities.

## 3. Long-term Debt

*U.S. Facility* On December 31, 2002, the Company obtained a credit facility from the Bank of Oklahoma, National Association (Bank of Oklahoma). Outstanding borrowings under the Company's previous credit facility with Wells Fargo Bank West National Association (Wells Fargo) were repaid in January 2003 using borrowings under the Bank of Oklahoma facility. The facility has a borrowing base of $19.0 million and matures in October 2005. No principal payments are required until maturity. The interest rates on amounts borrowed under the facility vary depending upon outstanding borrowings as a percentage of the borrowing base. Based upon the amount of current borrowings with Wells Fargo at December 31, 2002, the interest rate would equal LIBOR plus 2.5%. The facility is secured by certain U.S. oil and gas properties of the Company and contains various covenants which prohibit or limit the Company's ability to pay dividends, purchase treasury shares, incur indebtedness, sell properties or merge with another entity. The Company will also be required to maintain certain financial ratios.

The Company's former credit facility was with Wells Fargo. At December 31, 2002, the borrowing base was $17.2 million with outstanding borrowings of $16.5 million. The Company's average borrowing rate was approximately 3.7% at December 31, 2002. The Wells Fargo facility has been classified as long-term at December 31, 2002 because the facility was repaid subsequent to year end with borrowings from the new long-term credit facility with the Bank of Oklahoma. The Company was in compliance with all debt covenants at December 31, 2002.

In March 2003, Carbon USA closed on the sale of its working and leasehold interests in the Permian Basin. The sales price was $15.7 million with an effective date of January 1, 2003. The Company will initially use the proceeds to pay down debt. As a result of the sale, the Company and Bank of Oklahoma have initiated discussions to determine a revised borrowing base. See Note 12 to the Consolidated Financial Statements for additional information.

*Canadian Credit Facility* Carbon Canada's credit facility is an oil and gas reserve based line-of-credit with Canadian Imperial Bank of Commerce (CIBC). At December 31, 2002, the borrowing base was $8.9 million with outstanding borrowings of $6.3 million. The Canadian facility is secured by the Canadian oil and gas properties of the Company. The revolving phase of the Canadian facility expires on March 31, 2003. If the revolving commitment is not renewed, the loan will be converted into a term loan and will be reduced by consecutive monthly payments over a period not to exceed 24 months. Subject to possible changes in the borrowing base, CIBC has agreed that it will not require the Company to make principal payments under the term loan section of the facility until April 2004 at the earliest. As such, no amounts under the CIBC facility have been classified as current at December 31, 2002. The Canadian facility bears interest at a rate equal to banker's acceptance rates plus 1.5% or at the CIBC Prime rate plus .5%. The Company's weighted average interest rate was 5.0% at December 31, 2002.

The Canadian facility contains various covenants that limit the Company's ability to pay dividends, purchase treasury shares, incur indebtedness, sell properties, or merge with another entity. The Company was in compliance with all debt covenants at December 31, 2002.

The agreement with CIBC also provides for $3.5 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. The Company currently utilizes the swap facility to hedge a portion of its Canadian production as described in Note 9.

Scheduled maturities of indebtedness under the Canadian facility for the next five years are as follows:

| **Year ending December 31,** | | **Maturities** |
|---|---|---|
| | | **(in thousands)** |
| 2003 | $ | |
| 2004 | | 2,345 |
| 2005 | | 3,127 |
| 2006 | | 782 |
| 2007 | | |
| | $ | 6,254 |

**4. Commitments and Contingencies**

*Operating Leases* The Company leases office space and certain equipment under non-cancelable operating leases. The annual minimum payments related to those commitments are as follows (in thousands):

| | | **United States** | | **Canada** |
|---|---|---|---|---|
| 2003 | $ | 257 | $ | 178 |
| 2004 | | 229 | | 14 |
| 2005 | | 60 | | |
| Total | $ | 546 | $ | 192 |

*Transportation Agreements* The Company has entered into various natural gas transportation agreements in Canada. The Company typically assigns these transportation agreements to a buyer of the Company's production during the term of the natural gas sales contract between the Company and the buyer. The Company is typically paid on an index basis, net of transportation charges incurred by the buyer. The rights and obligations under these transportation agreements will revert back to the Company upon expiration of the natural gas sales contracts.

## 5. Stock Options and Award Plans

In 1999, the Company adopted a stock option plan. All salaried employees of the Company and its subsidiaries are eligible to receive both incentive stock options and nonqualified stock options. Directors and consultants who are not employees of the Company or its subsidiaries are eligible to receive nonqualified stock options, but not incentive stock options. The option price for the incentive stock options granted under the plan is to be not less than 100% of the fair market value of the shares subject to the options. The option price for the nonqualified stock options granted under the plan is to be not less than 85% of the fair market value of the shares subject to the options. The aggregate number of shares of common stock which may be granted pursuant to the plan may not exceed 700,000 shares.

The specific terms of grant and exercise are determined by the Company's Board of Directors. The options vest over a three-year period and expire ten years from the date of grant. A summary of the status of the Company's stock option plan as of December 31, 2002, 2001 and 2000 and changes during these periods is presented below:

| | For the Year Ended December 31, 2002 | | For the Year Ended December 31, 2001 | | For the Year Ended December 31, 2000 | |
|---|---|---|---|---|---|---|
| | Number of Option Shares | Weighted-Average Exercise Price | Number of Option Shares | Weighted-Average Exercise Price | Number of Option Shares | Weighted-Average Exercise Price |
| Outstanding at beginning of period | 551,834 | $ 5.47 | 590,500 | $ 5.30 | 115,000 | $ 5.50 |
| Granted | 57,500 | 8.86 | 34,000 | 8.16 | 520,500 | 5.29 |
| Exercised | (18,165) | 4.95 | (36,099) | 5.14 | | |
| Forfeited | (21,001) | 4.31 | (36,567) | 5.56 | (45,000) | 5.78 |
| Outstanding at end of year | 570,168 | $ 5.87 | 551,834 | $ 5.47 | 590,500 | $ 5.30 |
| Options exercisable at year end | 439,488 | | 374,156 | | 276,166 | |
| Shares available for grant at year end | 75,568 | | 112,067 | | 109,500 | |
| Weighted-average fair value of options granted during the year | | $ 3.73 | | $ 2.93 | | $ 1.51 |

The following table summarizes information about the Company's stock options outstanding at December 31, 2002:

| | Options Outstanding | | | Options Exercisable | |
|---|---|---|---|---|---|
| Range of Exercise Prices | Options Outstanding at Year end | Weighted-Average Remaining Contractual Life (Years) | Weighted-Average Exercise Price | Options Exercisable at Year end | Weighted-Average Exercise Price |
| $4.18 - $5.87 | 478,668 | 4.9 | $ 5.34 | 428,158 | $ 5.32 |
| $6.00 - $9.88 | 91,500 | 9.1 | $ 8.60 | 11,330 | $ 8.16 |
| $4.18 - $9.88 | 570,168 | 5.5 | $ 5.87 | 439,488 | $ 5.40 |

The fair value of each option grant is estimated on the date of the grant using the Black-Scholes option pricing model with the following assumptions:

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Expected option life years | 5.00 | 4.50 | 3.50 |

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Risk-free interest rate | 2.79% | 4.24% | 6.36% |
| Dividend yield | 0.00% | 0.00% | 0.00% |
| Volatility | 44.84% | 33.70% | 25.79% |

In 1999, the Company adopted a restricted stock plan for selected employees, directors and consultants of the Company and its subsidiaries. The aggregate number of shares of common stock which may be issued under the plan may not exceed 300,000 shares and at December 31, 2002 a total of 85,000 shares of common stock had been issued under the plan. The number of shares granted under this plan were 17,500, 0 and 27,500 for the years ended December 31, 2002, 2001 and 2000, respectively. The Company recognized compensation expense related to these grants of $149,000, $129,000, and $116,000 for the years ended December 31, 2002, 2001, and 2000, respectively. The Company recognizes compensation expense for restricted stock granted to employees equally over the three-year vesting period of the award based on the market value of the shares on the date of grant. To date, the Company has not issued any stock-based awards to non-employees.

## 6. Income Taxes

The following table sets forth the difference between the provision for income taxes and the amounts computed by applying the statutory federal income tax rate in thousands:

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2002 | 2001 | 2000 |
| Tax expense at 35% of income before income taxes | $ (4,832) | $ 1,811 | $ 743 |
| State income taxes | (340) | 9 | 17 |
| Change in the valuation allowance against deferred tax assets | 5,643 | | (192) |
| Impact of higher statutory rates on Canadian income | (17) | 401 | 151 |
| Canadian resource allowance | (447) | (1,016) | (375) |
| Canadian Crown payments (net of Alberta Royalty Tax Credit) | 550 | 934 | 455 |
| Other | 190 | (48) | (132) |
| | $ 747 | $ 2,091 | $ 667 |

Deferred income taxes generally result from recognizing income and expenses at different times for financial and tax reporting. In the U.S., the largest differences are the tax effects of the capitalization of certain development, exploration and other costs, recording proceeds from the sale of properties in the full cost pool and the provision for impairment of oil and gas properties. In Canada, the largest difference results from accelerated recovery of capital expenditures for tax purposes. The following table sets forth the Company's deferred tax assets and liabilities at December 31, 2002 and 2001:

| | December 31, 2002 | | |
|---|---|---|---|
| | United States | Canada | Total |
| | | (in thousands) | |
| Deferred tax assets: | | | |
| Net operating loss carryforwards | $ 4,230 | $ | $ 4,230 |
| Unrealized hedging losses | 325 | 129 | 454 |
| Property and equipment | 1,413 | | 1,413 |
| Gross deferred tax assets | 5,968 | 129 | 6,097 |
| Deferred tax liabilities: | | | |
| Property and equipment | | (3,222) | (3,222) |

| | December 31, 2002 | | |
|---|---|---|---|
| Gross deferred tax liabilities | | (3,222) | (3,222) |
| Valuation allowance | (5,643) | | (5,643) |
| Net deferred tax asset (liability) | $ 325 | $ (3,093) | $ (2,768) |

| | December 31, 2001 | | |
|---|---|---|---|
| | United States | Canada | Total |
| | | (in thousands) | |
| Deferred tax assets: | | | |
| Net operating loss carryforwards | $ 2,352 | $ | $ 2,352 |
| Gross deferred tax assets | 2,352 | | 2,352 |
| Deferred tax liabilities: | | | |
| Property and equipment | (1,537) | (3,195) | (4,732) |
| Unrealized hedging gains | (74) | (128) | (202) |
| Other | (69) | | (69) |
| Gross deferred tax liabilities | (1,680) | (3,323) | (5,003) |
| Net deferred tax asset (liability) | $ 672 | $ (3,323) | $ (2,651) |

As of December 31, 2002, the Company had net operating loss carryforwards for federal income tax purposes of $11.3 million which expire in the years 2019 through 2022. Due to the uncertainty regarding the realization of the deferred tax assets relating to the net operating loss carryforwards and other temporary differences in the United States, a valuation allowance has been recorded for the Company's deferred tax assets in the United States as of December 31, 2002. The Company makes periodic reviews of the realizability of its net deferred tax assets and will make adjustments to the valuation allowance when it is more likely than not that the net deferred tax assets will be realized.

## 7. Business and Geographical Segments

Segment information has been prepared in accordance with SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information." For the years ended December 31, 2002, 2001 and 2000, Carbon had two reportable segments: Carbon USA and Carbon Canada, representing oil and gas operations in the United States and Canada, respectively. The Company evaluates performance of its reportable segments based on profit or loss from oil and gas operations before income taxes. Because Carbon USA and Carbon Canada are managed separately based on their geographic locations, the Company identified them as reportable segments under SFAS No. 131.

The segment data presented below was prepared on the same basis as Carbon's consolidated financial statements (in thousands).

| For the Year Ended December 31, 2002 | | | For the Year Ended December 31, 2001 | | | For the Year Ended December 31, 2000 | For the Period from February 18, through December 31, 2000 | |
|---|---|---|---|---|---|---|---|---|
| United States | Canada | Total | United States | Canada | Total | United States | Canada | Total |

| | | | | | | | | For the Period from February 18, through December 31, 2000 | |
|---|---|---|---|---|---|---|---|---|---|
| Revenues: | | | | | | | | | |
| Oil and gas sales | $ 10,154 | $ 7,573 | $ 17,727 | $ 11,455 | $ 11,080 | $ 22,535 | $ 12,100 | $ 5,374 | $ 17,474 |
| Marketing and other, net | 344 | | 344 | 532 | 2 | 534 | 245 | (70) | 175 |
| | 10,498 | 7,573 | 18,071 | 11,987 | 11,082 | 23,069 | 12,345 | 5,304 | 17,649 |
| Expenses: | | | | | | | | | |
| Oil and gas production costs | 4,793 | 1,785 | 6,578 | 4,669 | 1,626 | 6,295 | 4,820 | 793 | 5,613 |
| Depreciation, depletion and amortization | 3,626 | 2,516 | 6,142 | 3,536 | 2,698 | 6,234 | 4,042 | 1,494 | 5,536 |
| Full cost ceiling impairment | 12,003 | 1,215 | 13,218 | | | | | | |
| General and administrative, net | 2,868 | 2,019 | 4,887 | 2,767 | 1,736 | 4,503 | 1,989 | 1,260 | 3,249 |
| Interest and other, net | 804 | 250 | 1,054 | 653 | 210 | 863 | 917 | 211 | 1,128 |
| Total operating expenses | 24,094 | 7,785 | 31,879 | 11,625 | 6,270 | 17,895 | 11,768 | 3,758 | 15,526 |
| Income (loss) before income taxes | (13,596) | (212) | (13,808) | 362 | 4,812 | 5,174 | 577 | 1,546 | 2,123 |
| Income tax provision | 746 | 1 | 747 | 135 | 1,956 | 2,091 | 44 | 623 | 667 |
| Income (loss) before cumulative effect of change in accounting principle | $ (14,342) | $ (213) | $ (14,555) | $ 227 | $ 2,856 | $ 3,083 | $ 533 | $ 923 | $ 1,456 |
| Total assets | $ 29,298 | $ 23,006 | $ 52,304 | $ 42,429 | $ 19,939 | $ 62,368 | $ 44,279 | $ 18,201 | $ 62,480 |
| Capital expenditures | $ 4,484 | $ 6,120 | $ 10,604 | $ 16,615 | $ 6,709 | $ 23,324 | $ 4,848 | $ 3,093 | $ 7,941 |

## 8. Major Customers

For the year ended December 31, 2002, revenues from the sale of natural gas to one customer of the Company's U.S. operations and two customers of the Company's Canadian operations represented approximately 12%, 11% and 16%, respectively, of the Company's consolidated revenues.

For the year ended December 31, 2001, revenues from the sale of natural gas to one customer of the Company's Canadian operations represented approximately 34% of the Company's consolidated revenues.

For the year ended December 31, 2000, revenues from the sale of natural gas to one customer of the Company's U.S. operations and one customer of the Company's Canadian operations represented approximately 16% and 20%, respectively, of the Company's consolidated revenues.

Management believes that the loss of any individual purchaser would not have a long-term material adverse impact on the financial position or results of operations of the Company.

## 9. Derivative Instruments

*Interest Rate Swap Agreements* During 2002, the Company entered into interest rate swap agreements that effectively converted a portion of its variable rate borrowings in the United States to fixed rate debt for periods of up to two years, reducing the impact of interest rate increases or decreases on future income. Quarterly settlements from interest rate swaps that qualify for hedge accounting treatment are recognized as an adjustment to interest expense. Gains or losses from interest rate swaps that do not qualify for hedge accounting treatment are recognized in the current period as a component of marketing and other revenue, net. The cash flows from such agreements are included in operating activities in the consolidated statements of cash flow. The table below sets forth the Company's interest rate derivative contracts in place at December 31, 2002 that were treated as cash flow hedges for accounting purposes:

| Notional Amount | Contract Expiration Date | LIBOR Fixed Rate | Derivative Asset/ (Liability) |
|---|---|---|---|
| (in thousands) | | | |
| $3,700 | May 2003 | 3.46% | $ (37) |
| 2,000 | October 2003 | 3.77% | (46) |
| 800 | October 2003 | 3.82% | (19) |
| 1,000 | March 2004 | 4.15% | (34) |
| 2,500 | April 2004 | 4.24% | (101) |
| | | | $ (237) |

Interest rates reflective of the Company's interest rate swap agreements were correlative with the LIBOR rates used to determine the Company's borrowing rate. As a result, no ineffectiveness was recognized related to the Company's interest rate swap agreements during the year ended December 31, 2002. During 2002, settlements under these interest rate swap agreements of $142,000 were recognized as additional interest expense. As of December 31, 2002, the Company had net unrealized derivative losses of $237,000 ($147,000 after tax) related to its interest rate swap agreements. The Company expects to reclassify $199,000 of these net unrealized losses to earnings during the next twelve month period.

*Commodity Derivative Instruments and Hedging Activities* The Company may use certain financial instruments including swaps, collars, futures and other contracts in an attempt to reduce exposure to market fluctuations in the price of oil and natural gas.

Pursuant to Company guidelines, the Company utilizes derivative instruments only as a hedging mechanism and does not enter into speculative transactions. Gains or losses from financial instruments that qualify for hedge accounting treatment are recognized as an adjustment to sales revenue during the period in which the financial instrument matures. Gains or losses from financial instruments that do not qualify for hedge accounting treatment are recognized during the current period as a component of marketing and other revenue, net. The cash flows from such instruments are included in operating activities in the consolidated statements of cash flows. The following table sets forth the hedge gains (losses) realized by the Company for 2002, 2001 and 2000 (in thousands):

| | For the Year Ended December 31, 2002 | | For the Year Ended December 31, 2001 | | For the Year Ended December 31, 2000 | |
|---|---|---|---|---|---|---|
| | United States | Canada | United States | Canada | United States | Canada |
| Oil | $ (83) | $ (8) | $ 25 | $ 33 | $ (414) | $ (186) |
| Natural gas | 400 | 3 | (1,475) | (571) | (2,608) | (987) |

The table below sets forth the Company's derivative financial instrument positions related to its natural gas and oil production that qualify for hedge accounting treatment at December 31, 2002:

Swaps:

| Carbon USA Contracts | | | | Carbon Canada Contracts | | | |
|---|---|---|---|---|---|---|---|
| Time Period | Bbl/ MMBtu | Weighted Average Fixed Price Bbl/MMBtu | Derivative Asset/ (Liability) | Time Period | Bbl/ MMBtu | Weighted Average Fixed Price Bbl/MMBtu | Derivative Asset/ (Liability) |
| | | | (thousands) | | | | (thousands) |
| **Gas** | | | | **Gas** | | | |
| 01/01/03-12/31/03 | 1,400,000 | $ 3.07 | $ (541) | 01/01/03-12/31/03 | 216,000 | $ 2.83 | $ (242) |
| **Oil** | | | | **Oil** | | | |
| 01/01/03-12/31/03 | 46,000 | $ 25.42 | $ (76) | 01/01/03-12/31/03 | 37,000 | $ 25.47 | $ (57) |

The Company periodically enters into long-term physical contracts for a portion of its natural gas and oil production. The table below sets forth fixed price sales contracts at December 31, 2002:

Fixed price contracts:

| Carbon USA Contracts | | | Carbon Canada Contracts | | |
|---|---|---|---|---|---|
| **Time Period** | **MMBtu** | **Weighted Average Fixed Price MMBtu** | **Time Period** | **MMBtu** | **Weighted Average Fixed Price MMBtu** |
| **Gas** | | | **Gas** | | |
| 01/01/03-03/31/03 | 180,000 | $ 2.57 | 01/01/03-12/31/03 | 778,000 | $ 3.16 |

During 2001, the Company entered into certain commodity derivative contracts with Enron North America Corporation (ENAC), a subsidiary of Enron Corporation (Enron). On December 2, 2001, Enron and ENAC filed for Chapter 11 bankruptcy, and the Company determined that the ENAC contracts no longer qualified for cash flow hedge accounting under SFAS No. 133. Consequently, the Company recorded a loss of $328,000 for the year ended December 31, 2001, based on the estimated fair value of the derivative contracts as determined by the future commodity price markets and deferred $328,000 ($205,000 after tax) in accumulated other comprehensive income. The amount deferred in accumulated other comprehensive income at December 31, 2001 of $246,000 ($156,000 after tax) was reclassified to earnings during 2002 based on the originally scheduled settlement periods of the contracts.

During the year ended December 31, 2002, net hedging gains of $196,000 ($122,000 after tax) relating to commodity derivative contracts, excluding amounts related to the ENAC contracts discussed above, were transferred from accumulated other comprehensive income to earnings. The fair value of outstanding commodity derivative contracts designated as hedges decreased by $968,000 ($570,000 after tax). Oil and natural gas prices reflective of the Company's hedge contracts were correlative with the published indices used to sell the Company's production. As a result, no ineffectiveness was recognized related to the Company's hedge contracts during the year ended December 31, 2002. As of December 31, 2002, the Company had net unrealized commodity derivative losses of $916,000 million ($554,000 after tax). The Company expects to reclassify all of these net unrealized losses to earnings during the next twelve month period.

**10. Fair Value of Financial Instruments**

The Company's financial instruments consist of cash, cash equivalents, accounts receivable, accounts payable, derivative instruments and long-term debt. Except for long-term debt, the carrying amounts of such financial instruments approximate fair value due to their short maturities. As a result of the variable interest rates on the Company's debt facilities at December 31, 2002, the fair market value of long-term debt was not materially different from its carrying amount. The Company's derivative instruments, which are intended to manage commodity price risks are recorded at fair market value.

**11. Marketing, Trading and Other Activities**

The Company formerly engaged in natural gas trading activities in the United States which involved purchasing natural gas from third parties and selling natural gas to other parties. In 2001, the Company reduced its efforts concerning the marketing of third party natural gas and completely exited the business in 2002. Trading income associated with these activities is presented on a net basis in the statements of operations as a component of marketing and other revenues. The following table sets forth the gross trading activities and other significant components of marketing and other revenue (in thousands):

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | **2002** | **2001** | **2000** |
| Revenues, gross | $ | $ 4,145 | $ 5,445 |
| Operating expenses, gross | | 4,037 | 5,515 |
| Net trading income (loss) | | 108 | (70) |
| Non-hedge derivative contracts | | 1,290 | |
| Impairment of accounts receivable | (5) | (625) | |
| Non-cash income (charge) related to impaired oil and gas hedges | 244 | (328) | |
| Gathering | 119 | 90 | 47 |

| | For the Year Ended December 31, | | |
|---|---|---|---|
| Section 29 tax credits | | | 176 |
| Other | (14) | (1) | 22 |
| Total marketing and other revenue | $ 344 | $ 534 | $ 175 |

**12. Subsequent Events**

On October 30, 2002, Carbon Canada passed a special resolution that amended its articles of association in order to consolidate its issued and outstanding common shares on a one-for-2,500 basis. On November 15, 2002, Carbon Canada initiated the exchange of common shares for post-consolidation shares or a cash payment in lieu of fractional post-consolidation shares. The exchange was completed on January 13, 2003. After the completion of the exchange, Carbon owns 100% of the stock of Carbon Canada.

**13. Events Subsequent to Independent Auditors' Report (Unaudited)**

On March 24, 2003, Carbon USA closed on the sale of its interests in 97 gross (23.3 net) wells and 25,400 gross (8,200 net) acres located primarily in southeast New Mexico. The purchase price was $15.7 million in cash, with an effective date of January 1, 2003. Proceeds from the sale were used to repay borrowings under the Company's U.S. credit facility with Bank of Oklahoma.

On March 31, 2003, Carbon announced that it had entered into an Agreement and Plan of Reorganization (the Merger Agreement) with Evergreen Resources, Inc. (Evergreen). Under the Merger Agreement, Carbon will merge with a subsidiary of Evergreen, and Carbon shareholders will receive .275 shares of Evergreen common stock for each outstanding share of Carbon common stock (and cash in lieu of any fractional shares). As a result of the merger, Carbon will become a wholly owned subsidiary of Evergreen. The merger is intended to be a tax-free, stock-for-stock transaction.

The Boards of Directors of Carbon and Evergreen each unanimously approved the Merger Agreement. At the time of execution of the agreement, each of Yorktown Energy Partners III, L.P., and Patrick R. McDonald, President and Chief Executive Officer of Carbon, who beneficially own approximately 73.2% and 6.0%, respectively, of Carbon's outstanding common stock, has executed an agreement with Evergreen obligating each of them to vote all shares over which it has voting control in favor of the merger.

RBC Capital Markets has acted as the financial advisor to Carbon and rendered a fairness opinion to the Board of Directors of Carbon.

Completion of the merger, which is subject to customary conditions, including approval by the shareholders of Carbon, is expected to occur late in the second quarter or in the third quarter of 2003. The Merger Agreement contains a $2.5 million termination fee payable by Carbon if the Merger Agreement is terminated under certain circumstances.

The Company has been informed by Evergreen that the Company's U.S. credit facility with Bank of Oklahoma is expected to be repaid at the close of the proposed merger of the Company with Evergreen. In regards to the Company's Canadian credit facility, the Company has obtained the consent of CIBC to the merger of the Company with Evergreen.

**14. Disclosures about Oil and Gas Activities**

(A)
Costs Incurred in Oil and Gas Producing Activities

The following table sets forth costs incurred in oil and gas property acquisition, exploration and development activities for the years ended December 31, 2002, 2001 and 2000:

| | United States | Canada | Total |
|---|---|---|---|
| | | (in thousands) | |
| **2002** | | | |
| Acquisition of properties: | | | |

| | United States | Canada | Total |
|---|---|---|---|
| Proved properties | $ | $ 1,046 | $ 1,046 |
| Unproved properties | 785 | 502 | 1,287 |
| Exploration | 1,827 | 296 | 2,123 |
| Development | 2,120 | 4,430 | 6,550 |
| Total | $ 4,732 | $ 6,274 | $ 11,006 |
| **2001** | | | |
| Acquisition of properties: | | | |
| Proved properties | $ | $ | $ |
| Unproved properties | 1,540 | 525 | 2,065 |
| Exploration | 9,513 | 214 | 9,727 |
| Development | 5,300 | 5,440 | 10,740 |
| Total | $ 16,353 | $ 6,179 | $ 22,532 |
| **2000(1)** | | | |
| Acquisition of properties: | | | |
| Proved properties | $ | $ 14,176 | $ 14,176 |
| Unproved properties | 1,217 | 161 | 1,378 |
| Exploration | 2,895 | 19 | 2,914 |
| Development | 1,495 | 3,627 | 5,122 |
| Total | $ 5,607 | $ 17,983 | $ 23,590 |

(1) Canadian results for 2000 are the results of Carbon Canada subsequent to its acquisition by Carbon in February 2000.

(B) Aggregate Capitalized Costs

The following table sets forth the aggregate capitalized costs relating to oil and gas activities at the end of each of the years indicated:

| | December 31, 2002 | | |
|---|---|---|---|
| | United States | Canada | Total |
| | | (in thousands) | |
| Oil and gas properties, full cost method: | | | |
| Unevaluated properties not being amortized | $ 6,218 | $ 862 | $ 7,080 |
| Evaluated costs | 43,591 | 27,632 | 71,223 |

| | December 31, 2002 | | |
|---|---|---|---|
| Total capitalized costs | 49,809 | 28,494 | 78,303 |
| Less Accumulated DD&A | (23,419) | (7,705) | (31,124) |
| Net capitalized costs | $ 26,390 | $ 20,789 | $ 47,179 |

| | December 31, 2001 | | |
|---|---|---|---|
| | United States | Canada | Total |
| | (in thousands) | | |
| Oil and gas properties, full cost method: | | | |
| Unevaluated properties not being amortized | $ 6,892 | $ 608 | $ 7,500 |
| Evaluated costs | 41,247 | 21,503 | 62,750 |
| Total capitalized costs | 48,139 | 22,111 | 70,250 |
| Less Accumulated DD&A | (7,941) | (4,013) | (11,954) |
| Net capitalized costs | $ 40,198 | $ 18,098 | $ 58,296 |

The following table sets forth the oil and gas property costs not being amortized at December 31, 2002, by the year in which the costs were incurred (in thousands):

| | United States | Canada | Total |
|---|---|---|---|
| 2002 | $ 1,134 | $ 449 | $ 1,583 |
| 2001 | 1,059 | 413 | 1,472 |
| 2000 | 246 | | 246 |
| 1999 | 3,779 | | 3,779 |
| | $ 6,218 | $ 862 | $ 7,080 |

The Company anticipates that substantially all unevaluated costs will be classified as evaluated costs within five years.

(C)

Estimated Proved Oil and Gas Reserves (Unaudited)

The table below sets forth the estimated quantities of year end proved reserves after royalty burdens at December 31, 2002, 2001 and 2000. The reserve estimates for properties located in the United States were prepared by Ryder Scott Company, an independent reservoir engineering firm, and the Canadian reserve estimates were prepared by Sproule Associates Limited, independent geological petroleum engineering consultants.

| Oil and Liquids | | | Natural Gas | | |
|---|---|---|---|---|---|
| United States | (MBbl) Canada | Total | United States | (MMcf) Canada | Total |

| | Oil and Liquids | | | Natural Gas | | |
|---|---|---|---|---|---|---|
| Balance, December 31, 1999 | 228 | | 228 | 31,012 | | 31,012 |
| Revisions of previous estimates | 278 | | 278 | 4,179 | | 4,179 |
| Extensions, discoveries and additions | 70 | 146 | 216 | 283 | 7,727 | 8,010 |
| Purchases of reserves in place | | 355 | 355 | | 12,452 | 12,452 |
| Production | (69) | (40) | (109) | (3,374) | (1,312) | (4,686) |
| Balance, December 31, 2000 | 507 | 461 | 968 | 32,100 | 18,867 | 50,967 |
| Revisions of previous estimates | (10) | (51) | (61) | (679) | (2,560) | (3,239) |
| Extensions, discoveries and additions | 34 | 79 | 113 | 10,968 | 5,575 | 16,543 |
| Purchases of reserves in place | | 9 | 9 | | 405 | 405 |
| Production | (81) | (59) | (140) | (2,810) | (2,419) | (5,229) |
| Sales of reserves in place | (38) | | (38) | (5,587) | | (5,587) |
| Balance, December 31, 2001 | 412 | 439 | 851 | 33,992 | 19,868 | 53,860 |
| Revisions of previous estimates | 32 | 41 | 73 | 1,396 | (1,365) | 31 |
| Extensions, discoveries and additions | 22 | 120 | 142 | 5,310 | 7,305 | 12,615 |
| Purchases of reserves in place | | 7 | 7 | | 2,229 | 2,229 |
| Production | (91) | (50) | (141) | (3,049) | (2,232) | (5,281) |
| Sales of reserves in place | (110) | | (110) | (972) | | (972) |
| Balance, December 31, 2002 | 265 | 557 | 822 | 36,677 | 25,805 | 62,482 |
| Proved developed reserves(1): | | | | | | |
| December 31, 2000 | 382 | 411 | 793 | 26,422 | 16,193 | 42,615 |
| December 31, 2001 | 401 | 352 | 753 | 28,949 | 14,710 | 43,659 |
| December 31, 2002 | 237 | 426 | 663 | 28,569 | 17,403 | 45,972 |

(1) Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Reserve estimates are based upon various assumptions, including assumptions required by the Securities and Exchange Commission 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. 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 its control.

In accordance with applicable requirements of the SEC, estimates of the Company's future net revenues are determined using sale prices estimated to be in effect as of the date of the reserve estimates and are held constant throughout the life of the properties (except to the extent provided by contractual arrangements in existence at year end). Also in accordance with the applicable SEC guidelines, future production costs are held constant at the level observed at the date of the reserve estimates. Declines in the price of oil or gas decrease reserve values by lowering the future net revenues attributable to the reserves and may also reduce the quantities of reserves that are recoverable on an economic basis. Price increases may have the opposite effect. A significant decline in prices of natural gas or oil could have a material adverse effect on the Company's financial condition and results of operations. Prices received for future production and future production costs may vary, perhaps significantly, from the prices and costs assumed for purposes of the estimates.

In general, the volumes of production from Carbon's oil and gas properties decline as reserves of oil and gas are depleted. Except to the extent the Company acquires additional properties containing proved reserves or conducts successful exploration and development activities or both, the proved reserves of the Company will decline as reserves are produced. Reserves generated from future activities of the Company are highly dependent upon the level of success in acquiring or discovering additional reserves and the costs incurred in doing so.

(D)

Standardized Measure (Unaudited)

The standardized measure schedule is presented pursuant to the disclosure requirements of the SEC and SFAS No. 69, "Disclosures About Oil and Gas Producing Activities".

The standardized measure is intended to provide a standard of comparable measurement of the Company's estimated proved oil and gas reserves based on pricing and costs existing as of December 31, 2002, 2001 and 2000. Pursuant to SFAS No. 69, future oil and gas revenues are calculated by multiplying the oil and gas production volumes expected to be produced in each year throughout the life of the properties by the oil and gas prices in effect at the end of the reporting period. Future price changes are considered only to the extent provided by contractual arrangement in existence at year end. Production and development costs are based upon costs at each year end and are held constant for the life of the properties. Future income tax expenses are estimated by applying a combined federal and state statutory tax rate of 38% in the United States and a combined federal and provincial rate ranging from 37 - 41% in Canada with recognition of tax basis, net operating loss carryforwards and other statutory deductions. For standardized measure purposes, the Company estimates future income taxes using the "year-by-year" method. For ceiling test purposes, the Company estimates future income taxes using the "short-cut" method. Discounted amounts are based on a 10% annual discount rate.

The following table sets forth the Company's standardized measure of discounted future net cash flows at December 31, 2002, 2001 and 2000:

| | December 31, 2002 | | |
|---|---|---|---|
| | **United States** | **Canada** | **Total** |
| | (in thousands) | | |
| Future oil and gas revenue | $ 123,119 | $ 118,943 | $ 242,062 |
| Future production costs | (34,859) | (21,801) | (56,660) |
| Future development costs | (13,593) | (4,612) | (18,205) |
| Future income tax expense | (13,192) | (29,870) | (43,062) |
| Future net cash flows | 61,475 | 62,660 | 124,135 |
| 10% annual discount for estimated timing of cash flows | (25,470) | (16,897) | (42,367) |
| Standardized measure of discounted future net cash flows | $ 36,005 | $ 45,763 | $ 81,768 |

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2002 was based on average year end oil and liquids prices of $29.84 per barrel in the United States and $24.68 per barrel in Canada, and average year end natural gas prices of $3.14 per Mcf in the United States and $3.84 per Mcf in Canada.

| | December 31, 2001 | | |
|---|---|---|---|
| | **United States** | **Canada** | **Total** |
| | (in thousands) | | |
| Future oil and gas revenue | $ 84,038 | $ 55,219 | $ 139,257 |
| Future production costs | (24,141) | (18,698) | (42,839) |
| Future development costs | (6,734) | (3,497) | (10,231) |
| Future income tax expense | (6,224) | (8,537) | (14,761) |

| | December 31, 2001 | | |
|---|---|---|---|
| Future net cash flows | 46,939 | 24,487 | 71,426 |
| 10% annual discount for estimated timing of cash flows | (18,235) | (5,379) | (23,614) |
| Standardized measure of discounted future net cash flows | $ 28,704 | $ 19,108 | $ 47,812 |

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2001 was based on average year end oil and liquids prices of $18.45 per barrel in the United States and $13.02 per barrel in Canada, and average year end natural gas prices of $2.25 per Mcf in the United States and $2.30 per Mcf in Canada.

| | December 31, 2000 | | |
|---|---|---|---|
| | United States | Canada | Total |
| | (in thousands) | | |
| Future oil and gas revenue | $ 326,156 | $ 186,815 | $ 512,971 |
| Future production costs | (51,331) | (14,828) | (66,159) |
| Future development costs | (7,923) | (2,719) | (10,642) |
| Future income tax expense | (75,844) | (65,986) | (141,830) |
| Future net cash flows | 191,058 | 103,282 | 294,340 |
| 10% annual discount for estimated timing of cash flows | (79,804) | (27,872) | (107,676) |
| Standardized measure of discounted future net cash flows | $ 111,254 | $ 75,410 | $ 186,664 |

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2000 was based on average year end oil prices of $25.50 per barrel in the United States and $21.73 per barrel in Canada, and average year end natural gas prices of $9.76 per Mcf in the United States and $9.00 per Mcf in Canada.

The standardized measure of discounted future net cash flows should not be construed to be an estimate of the fair value of the Company's proved reserves. Changes in the demand for oil and gas, price changes, reserve recovery variances and other factors make such estimates inherently imprecise and subject to revision.

The tables below set forth the principle sources of changes in the standardized measure of discounted future net cash flows for the years ended December 31, 2002, 2001 and 2001:

| | December 31, 2002 | | |
|---|---|---|---|
| | United States | Canada | Total |
| | (in thousands) | | |
| Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at beginning of year | $ 28,704 | $ 19,108 | $ 47,812 |
| Changes resulting from: | | | |
| Sales and transfers of oil and gas produced, net of production costs | (5,044) | (5,793) | (10,837) |
| Net change in sales price and future production costs | 12,353 | 25,724 | 38,077 |

| | December 31, 2002 | | |
|---|---|---|---|
| Net changes in future development costs | (195) | 735 | 540 |
| Net changes due to extensions, discoveries and improved recovery | 2,034 | 16,218 | 18,252 |
| Revision of previous quantity estimates | 1,964 | (2,568) | (604) |
| Purchase of reserves in place | | 4,746 | 4,746 |
| Sales of reserves in place | (2,198) | | (2,198) |
| Accretion of discount | 3,111 | 2,468 | 5,579 |
| Net change in income tax | (3,857) | (12,575) | (16,432) |
| Other | (867) | (2,300) | (3,167) |
| Net changes | 7,301 | 26,655 | 33,956 |
| Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year | $ 36,005 | $ 45,763 | $ 81,768 |

| | December 31, 2001 | | |
|---|---|---|---|
| | United States | Canada | Total |
| | (in thousands) | | |
| Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at beginning of year | $ 111,254 | $ 75,410 | $ 186,664 |
| Changes resulting from: | | | |
| Sales and transfers of oil and gas produced, net of production costs | (8,236) | (9,993) | (18,229) |
| Net change in sales price and future production costs | (105,421) | (83,846) | (189,267) |
| Net changes in future development costs | 4,678 | 1,074 | 5,752 |
| Net changes due to extensions, discoveries and improved recovery | 8,964 | 4,924 | 13,888 |
| Revision of previous quantity estimates | (634) | (3,103) | (3,737) |
| Purchase of reserves in place | | 320 | 320 |
| Sales of reserves in place | (23,957) | | (23,957) |
| Accretion of discount | 15,353 | 11,146 | 26,499 |
| Net change in income tax | 39,872 | 33,520 | 73,392 |
| Other | (13,169) | (10,344) | (23,513) |
| Net changes | (82,550) | (56,302) | (138,852) |
| Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year | $ 28,704 | $ 19,108 | $ 47,812 |

| | December 31, 2000 | | |
|---|---|---|---|
| | United States | Canada(1) | Total |
| | (in thousands) | | |
| Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at beginning of year | $ 25,429 | $ | $ 25,429 |
| Changes resulting from: | | | |

| | December 31, 2000 | | |
|---|---|---|---|
| Sales and transfers of oil and gas produced, net of production costs | (10,302) | (6,961) | (17,263) |
| Net change in sales price and future production costs | 113,753 | | 113,753 |
| Net changes in future development costs | (1,269) | | (1,269) |
| Net changes due to extensions, discoveries and improved recovery | 2,243 | 35,084 | 37,327 |
| Revision of previous quantity estimates | 27,019 | | 27,019 |
| Purchase of reserves in place | | 76,377 | 76,377 |
| Accretion of discount | 2,619 | | 2,619 |
| Net change in income tax | (41,502) | (39,094) | (80,596) |
| Other | (6,736) | 10,004 | 3,268 |
| Net changes | 85,825 | 75,410 | 161,235 |
| Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year | $ 111,254 | $ 75,410 | $ 186,664 |

(1)
Changes in Canadian reserves for 2000 represent changes since the Company's acquisition of Carbon Canada in February 2000.

**15.** ***Quarterly Financial Data (Unaudited)***

The following table sets forth the Company's quarterly results of operations for 2002 and 2001:

| | 2002 | | | |
|---|---|---|---|---|
| | March 31, | June 30, | September 30, | December 31, |
| | (in thousands except per share data) | | | |
| Operating revenues | $ 3,987 | $ 4,528 | $ 4,108 | $ 5,448 |
| Operating expenses | 1,546 | 1,617 | 1,710 | 1,705 |
| Operating margin | 2,441 | 2,911 | 2,398 | 3,743 |
| Net income (loss) | (532) | (14,089) | (253) | 319 |
| Basic earnings per share | $ (0.09) | $ (2.31) | $ (0.04) | $ 0.05 |
| Diluted earnings per share | (0.09) | (2.31) | (0.04) | 0.05 |

| | 2001 | | | |
|---|---|---|---|---|
| | March 31, | June 30, | September 30, | December 31, |
| | (in thousands except per share data) | | | |
| Operating revenues | $ 8,594 | $ 6,613 | $ 3,936 | $ 3,926 |
| Operating expenses | 1,659 | 1,558 | 1,494 | 1,584 |
| Operating margin | 6,935 | 5,055 | 2,442 | 2,342 |
| Net income (loss) | 1,016 | 1,304 | (304) | (443) |
| Basic earnings per share | $ 0.17 | $ 0.22 | $ (0.05) | $ (0.07) |
| Diluted earnings per share | 0.16 | 0.21 | (0.05) | (0.07) |

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

Not applicable.

## PART III

**ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT**

The executive officers and directors are listed below with a description of their experience and certain other information. Each director was elected to serve until the next annual meeting of stockholders or until their successors are duly elected and qualified. Two of the Company's directors, Mr. Lawrence and Mr. Leidel, were persons selected as nominees by Yorktown Energy Partners III, L.P. (Yorktown) in accordance with the exchange agreement described in Item 13 below. Mr. McDonald was selected as a director pursuant to requirements of the exchange agreement and his employment agreement. Each of Carbon's two executive officers serves at the pleasure of the Board of Directors and in accordance with their employment agreements.

**Directors and Officers**

The following sets forth certain information about the executive officers and directors of the Company:

| Name | Age | Position |
|---|---|---|
| Patrick R. McDonald | 46 | President, Chief Executive Officer and Director |
| Kevin D. Struzeski | 44 | Treasurer and Chief Financial Officer |
| Cortlandt S. Dietler | 81 | Director |
| David H. Kennedy | 53 | Director |
| Bryan H. Lawrence | 60 | Director |
| Peter A. Leidel | 46 | Director |
| Harry A. Trueblood, Jr. | 77 | Director |

**Patrick R. McDonald** became Carbon's President, Chief Executive Officer and a director in September 1999. He has been Chairman and Chief Executive Officer since July 1998 of CEC Resources, which is the Canadian subsidiary of Carbon and is engaged in the exploration, development and production of oil, natural gas, and natural gas liquids in Canada. From 1987 until 1997, Mr. McDonald was Chairman and President of Interenergy Corporation, Denver, Colorado. Since January 1998, he has been the sole member of McDonald Energy, LLC. Mr. McDonald is a petroleum geologist.

**Kevin D. Struzeski** became Carbon's Treasurer and Chief Financial Officer on September 14, 1999. He has been Treasurer and Chief Financial Officer for CEC Resources since November 1998. Mr. Struzeski was employed as Accounting Manager, MediaOne Group from 1997 to 1998 and prior to that he was employed as Controller, Interenergy Corporation from 1995 to 1997.

**Cortlandt S. Dietler** has served as a director of Carbon since December 1999. Mr. Dietler has been the Chairman of TransMontaigne Inc., which owns and operates terminals and pipelines for the transportation of oil, gas and other petroleum products, since April 1995. Mr. Dietler was Chief Executive Officer of TransMontaigne from April 1995 through September 1999. He was the founder, Chairman and Chief Executive Officer of Associated Natural Gas Corporation, a natural gas gathering, processing and marketing company, prior to its 1994 merger with PanEnergy Corporation, on whose Board he served as an Advisory Director, prior to its merger with Duke Energy Corporation. Mr. Dietler also serves as a director of Hallador Petroleum Company (OTC-HPCO.OB), Cimarex Energy Co. (NYSE-XEC), and Forest Oil Corporation (NYSE-FST).

**David H. Kennedy** has served as a director of Carbon since September 1999. From March 1981 through December 1998, Mr. Kennedy was a managing director of First Reserve Corp. and was responsible for investing and monitoring part of its portfolio of energy investments. Since January 1999, Mr. Kennedy has acted as a consultant to and investor in the energy industry. He serves as a director of Maverick Tube Corporation (NYSE-MVK).

**Bryan H. Lawrence** has served as a director of Carbon since September 1999. Mr. Lawrence is a founder and member of Yorktown Partners LLC which was established in September 1997. Yorktown Partners LLC is the manager of private equity partnerships that invest in the energy industry. Mr. Lawrence had been employed at Dillon, Read & Co. Inc. since 1966, serving as a Managing Director until the merger of Dillon Read with SBC Warburg in September 1997. Mr. Lawrence also serves as a Director of Crosstex Energy, L.P. (NASDAQ-XTEX), D & K Healthcare Resources, Inc. (NASDAQ-DKWD), Hallador Petroleum Company (OTC-HPCO.OB), TransMontaigne Inc. (ASE-TMG), Vintage Petroleum, Inc. (NYSE-VPI) and certain non-public companies in the energy industry in which the Yorktown partnerships hold equity interests.

**Peter A. Leidel** has served as a director of Carbon since September 1999. Mr. Leidel is a founder and member of Yorktown Partners LLC which was established in September 1997. Yorktown Partners LLC is the manager of private equity partnerships that invest in the energy industry. Previously, he was a partner of Dillon, Read & Co. Inc.'s venture capital fund and has invested in a variety of private companies with a particular focus on energy investments since 1983. He was previously employed in corporate treasury positions at Mobil Corporation and worked for KPMG Peat Marwick and the U.S. Patent and Trademark Office. Mr. Leidel is a director of Cornell Companies, Inc. (NYSE-CRN), Willbros Group, Inc. (NYSE-WG) and certain non-public companies in the energy industry in which the Yorktown partnerships hold equity interests.

**Harry A. Trueblood, Jr.** has served as a director of Carbon since February 2000. Mr. Trueblood is currently owner and managing member of HAT Resources, LLC. He was formerly President and Chief Executive Officer of CEC from 1972 until June 1998. Mr. Trueblood also was founder and served as Chairman, President and CEO of Columbus Energy Corp., the former parent of CEC, from 1982 through December 2000 and also was founder and served as President and CEO of Consolidated Oil & Gas, Inc., the former parent of both CEC and Columbus from 1958 to 1988.

## COMPLIANCE WITH SECTION 16(a) OF THE SECURITIES EXCHANGE ACT OF 1934

Section 16(a) of the Securities Exchange Act of 1934 requires executive officers, directors and persons who beneficially own more than ten percent of the Company's stock to file initial reports of ownership and reports of changes of ownership at specified times with the Securities and Exchange Commission and the American Stock Exchange. Copies of such reports are required to be furnished to the Company.

Based solely on a review of copies of such reports furnished to the Company, the Company believes that all Section 16(a) filing requirements of its directors, officers and beneficial owners of more than 10% of the outstanding shares of the Company for the year ending December 31, 2002 have been complied with in a timely manner.

## ITEM 11. EXECUTIVE COMPENSATION

The following table summarizes the compensation paid during the last three fiscal years by Carbon to each of the two executive officers of Carbon.

### SUMMARY COMPENSATION TABLE

| | Annual Compensation | | | Long Term Compensation | | |
|---|---|---|---|---|---|---|
| **Name and Principal Position** | **Fiscal Year** | **Salary ($)** | **Bonus(1) ($)** | **Restricted Stock Awards(2) ($)** | **Securites Underlying Options(3) (#)** | **All Other Compensation ($)** |
| Patrick R. McDonald | 2002 | 244,764 | 301,900 | | | 166,662(4) |
| President and Chief Executive Officer | 2001 | 229,050 | 138,000 | | | 6,300 |
| | 2000 | 203,642 | 102,733 | 58,625 | | 14,035 |
| Kevin D. Struzeski | 2002 | 115,000 | 53,000 | 19,975 | 5,000 | 28,452(5) |
| Chief Financial Officer and Treasurer | 2001 | 110,000 | 25,000 | | | 5,250 |
| | 2000 | 100,321 | 30,000 | 14,656 | 5,000 | 9,774 |

(1)

Includes $250,000 and $40,000 paid in January 2003 to Mr. McDonald and Mr. Struzeski, respectively, for bonuses accrued in 2002.

(2)

Granted pursuant to the Company's 1999 restricted stock plan and valued at the fair market value of $7.99 and $5.86 per share on the date of grant for 2002 and 2000, respectively. No shares were granted under this plan during 2001. The restricted stock vests 33.33% each year over a three year period from the date of the grant. All restricted stock outstanding under this plan becomes fully vested upon a change of control as defined in the plan. A change of control would include shareholder approval of Carbon's proposed merger with Evergreen Resources, Inc.

(3)

Granted pursuant to the Company's 1999 stock option plan.

(4)

Includes contributions of $5,500, $5,250 and $4,800 made by the Company in 2002, 2001 and 2000, respectively, to the Company's 401(k) plan on behalf of Mr. McDonald, $1,050 attributable to the Company's payment for a term life insurance policy on behalf of Mr. McDonald in 2002, 2001 and 2000, and $108,160 related to a stock appreciation amount paid in 2002 to Mr. McDonald by Carbon for the cancellation of an option. For further information see Item 13 below. The balance of the amounts for 2002 and 2000 represent amounts paid for untaken leave.

(5)

Includes contributions of $5,500, $5,250 and $5,250 made by the Company in 2002, 2001 and 2000, respectively, to the Company's 401(k) plan on behalf of Mr. Struzeski. The balance of the amounts for 2002 and 2000 represent amounts paid for untaken leave.

## STOCK OPTION GRANTS AND EXERCISES

In 1999, Carbon adopted a stock option plan. All salaried employees of the Company and its subsidiaries are eligible to receive both incentive stock options and nonqualified stock options. Directors and consultants who are not employees of the Company or its subsidiaries are eligible to receive non-qualified stock options, but not incentive stock options under the plan. The option price for the incentive stock options granted under the plan are not to be less than 100% of the fair market value of the shares subject to the option. The option price for the nonqualified stock options granted under the plan are not to be less than 85% of the fair market value of the shares subject to the options. All outstanding options under the stock option plan become immediately exercisable in full, whether or not there are vesting requirements, upon the occurrence of a change in control as defined in the plan. A change of control would include shareholder approval of Carbon's proposed merger with Evergreen Resources, Inc. The term of any stock option cannot exceed ten years. The aggregate number of shares of common stock which may be issued under options granted pursuant to the plan may not exceed 700,000 shares.

The specific terms of grant and exercise are determined by the Compensation Committee of the Board of Directors.

The following table sets forth information concerning individual grants of stock options made to Carbon's executive officers for the fiscal year ended December 31, 2002:

| | | | | | Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation for Option Term(1) | |
|---|---|---|---|---|---|---|
| **Name** | **Number of Securities Underlying Options Granted** | **% of Total Options Granted to Employees in Fiscal Year** | **Exercise Price ($)** | **Expiration Date** | **5% ($)** | **10% ($)** |
| Kevin D. Struzeski | 5,000 | 8.3% | 7.99 | 2/29/12 | 25,124 | 63,670 |

(1)

The columns present hypothetical future realizable values of the options, obtainable upon exercise of the option's exercise price, assuming Carbon's common stock appreciates at a 5% and 10% compound annual rate over the term of the options. The 5% and 10% rates of market price appreciation are presented as examples pursuant to rules of the SEC and do not reflect management's prediction of the future market price of our common stock. No gain to the optionees is possible without an increase in the market price of the common stock above the option price. There can be no assurance that the potential realizable values shown in this table will be achieved. The potential realizable values presented are not intended to indicate the value of the options.

**YEAR-END OPTION VALUE TABLE**

The following table summarizes information as of December 31, 2002 with respect to exercisable and non-exercisable options held by the Company's executive officers. The table also includes the value of "in-the-money" options, which represents the closing price of a share of common stock on December 31, 2002 of $10.00, less the exercise price, multiplied by the number of shares subject to the unexercised options.

**2002 YEAR-END OPTION VALUES**

| | Number of Securities Underlying Unexercised Options at Year-End | | In-the-Money Value of Unexercised Options at Year End ($) | |
|---|---|---|---|---|
| **Name** | **Exercisable** | **Unexercisable** | **Exercisable** | **Unexercisable** |
| Patrick R. McDonald | 148,000 | | 666,000 | |
| Kevin D. Struzeski | 48,333 | 6,667 | 233,790 | 16,947 |

**EMPLOYMENT AGREEMENTS**

In October, 2002, Patrick R. McDonald and Carbon entered into a three-year employment agreement, which provides for Mr. McDonald to be the President and Chief Executive Officer of Carbon at a base salary of not less than $242,000 per year, to be adjusted on each July 1 for cost of living increases in the U.S. consumer price index and to be reviewed annually by the Board of Directors or the Compensation Committee. Carbon is to provide Mr. McDonald medical, dental and disability benefits and is to maintain for his benefit a life insurance policy in the amount of $2 million. Carbon is also to pay for certain membership fees and dues of certain organizations to which Mr. McDonald has historically belonged. If a payment to Mr. McDonald is subject to an excise tax under the Internal Revenue Code, Carbon will pay to Mr. McDonald an additional amount to cover the excise tax on an after-tax basis. According to the employment agreement, Carbon is also to nominate and endorse Mr. McDonald as a director on Carbon's Board of Directors so long as he is an officer of Carbon. Prior to this employment agreement, Mr. McDonald had a three-year employment agreement which expired in October 2002.

If Mr. McDonald's employment is terminated by Carbon for any reason other than "cause" (as defined in the agreement) or upon the death or disability of Mr. McDonald or if Mr. McDonald terminates his employment because of a material breach of the employment agreement by Carbon or because of a change in the position of Mr. McDonald with Carbon, then Mr. McDonald is to be paid a lump sum payment equal to 300% of his average annual compensation (which includes base salary and incentive compensation). Also, in that event, his options and restricted stock become 100% vested.

Either Carbon or Mr. McDonald may terminate the agreement if there is a change in control of Carbon as defined in the employment agreement. In the event of a change in control not supported by a majority of the Board of Directors, Mr. McDonald is to be paid 400% of his average annual compensation upon termination of the employment agreement. In the event of a change in control supported by the Board of Directors, Mr. McDonald is to be paid 300% of his average annual compensation upon termination of the employment agreement by Carbon or 300% of his compensation upon termination of his employment by him. In addition, upon a change in control, any outstanding stock options, stock appreciation rights and incentive awards (including restricted stock) granted to Mr. McDonald become 100% vested, without any restrictions.

In October, 1999, the Company entered into a two-year employment agreement with Mr. Struzeski. The initial two year term ended in October, 2001, after which the agreement continues from year to year. The agreement provides for Mr. Struzeski to be the Chief Financial Officer of Carbon at a base salary of $100,000 per year to be reviewed annually by the Board of Directors or the Compensation Committee, together with all benefits offered by Carbon to Carbon's employees generally. If Mr. Struzeski's employment is terminated by Carbon for any reason other than "cause" or upon the death or disability of Mr. Struzeski or if Mr. Struzeski terminates his employment because of a change in the position of Mr. Struzeski with Carbon, Carbon is to pay Mr. Struzeski an amount equal to his compensation (pro rated on a monthly basis) multiplied by the remaining months of his employment agreement. Also, in that event, his options and restricted stock become 100% vested. The employment agreement with Mr. Struzeski provides that either Carbon or Mr. Struzeski may terminate the contract if there is a change in control of Carbon. In the event of a change in control not supported by a majority of the Board of Directors, Mr. Struzeski is to be paid 300% of his average annual compensation (which includes base salary and incentive compensation) upon termination of the employment agreement. In the event of a change in control supported by the Board of Directors, Mr. Struzeski is to be paid 200% of his compensation upon termination of his employment agreement by the Company or 100% of his compensation upon termination of his employment by him. In the event of a change in control, any outstanding stock options, stock appreciation rights and incentive awards (including restricted stock) granted to Mr. Struzeski will become 100% vested, without restrictions.

**COMPENSATION COMMITTEE REPORT ON EXECUTIVE COMPENSATION**

The Compensation Committee of the Board of Directors is comprised of non-employee directors of the Company. The Committee establishes and reviews the compensation policies of the Company and administers the Company's Stock Option and Restricted Stock Plans. The Committee also establishes salary and bonus levels for officers.

The Committee believes that it is in the best interest of the Company and its shareholders for the cash compensation of its executive officers to be competitive with the compensation of executives of oil and gas companies of comparable size and geographical location and complexity of operations.

Awards of stock options and restricted stock are intended to serve as long-term compensation designed to align the interests of Carbon's employees with the growth objectives of Carbon and its shareholders.

Stock options are granted only at the market price of the Company's stock and will have value only if the price of the Company's common stock increases. Options typically have a term of ten years and vest 33% each year for three years following the grant.

Restricted stock grants typically vest 33% each year for three years following the grant.

The Committee considers various factors to determine the performance of the Company and its executives, including growth in natural gas and oil production, growth in reserves of natural gas and oil, cash flow, earnings before interest, taxes and depreciation (EBITDA) and net income. The Committee has not established any particular formula nor identified any one particular factor as being more important than others in determining the performance of the Company and its executives.

For 2002, Carbon USA reported increased production volumes and net proved oil and natural gas reserves, and a decline in revenue, cash flow, EBITDA and net income. Production rose by 10% to an average of 9.9 MMcfe a day. Net proved reserves increased by 5% to 38.3 Bcfe, replacing over 196% of last years' production. Oil and gas revenues for 2002 decreased by 17% to $8.6 million. Cash flow before changes in working capital during 2002 was $1.9 million, a decrease of 29% from cash flow before changes in working capital reported in 2001. EBITDA declined to $2.8 million, a decrease of 7% from that reported for 2001. Carbon USA reported a $14.3 million net loss for the year, compared to a net loss of $1.3 million reported in 2001. The decrease in oil and gas revenue, cash flow before changes in working capital and EBITDA were due to a 26% decrease in the price of gas received in 2002 compared to 2001. In addition, the net loss for 2002 included a full cost ceiling impairment of $12.0 million due to low spot gas prices at June 30, 2002.

For 2002, Carbon Canada reported increased net proved oil and natural gas reserves and a decline in production volumes, revenue, cash flow, EBITDA and net income. Net proved reserves increased by 30% to 29.1 Bcfe, replacing over 362% of last years' production. Production declined by 9% to an average of 6.9 MMcfe a day due primarily to the voluntary curtailment of natural gas and liquids production during the third quarter of 2002 due to low natural gas prices. Oil and gas revenues for 2002 decreased by 32% to $7.6 million. Cash flow before changes in working capital during 2002 was $3.5 million, a decrease of 40% from cash flow before changes in working capital reported in 2001. EBITDA declined to $3.8 million, a decrease of 51% from that reported for 2001. Carbon Canada reported a $.2 million net loss for the year, compared to net income of $2.9 million reported in 2001. The decrease in oil and gas revenues, cash flow before changes in working capital, and EBITDA were due to a 27% decrease in the price of gas received in 2002 compared to 2001. In addition, the net loss for 2002 included a full cost ceiling impairment of $1.2 million due to low spot gas prices at June 30, 2002.

The common stock of Carbon increased from $8.69 per share at December 31, 2001 to $10.00 per share at December 31, 2002, an increase of 15%.

The Committee reviewed the Company's operational and financial performance during 2002 to determine the level of compensation of its Chief Executive Officer, Patrick R. McDonald. Mr. McDonald has an employment agreement with the Company which provides for a base salary to be reviewed annually by the Compensation Committee of the Board of Directors or the Board of Directors. Mr. McDonald's base salary at January 1, 2002 was $240,000 and increased to $242,880, effective July 1, 2002. Based upon the Company's operational and financial results, the Compensation Committee recommended an increase to Mr. McDonald's base salary to $250,000 effective January 1, 2003 and recommended that Mr. McDonald receive a performance bonus of $250,000 to be paid January 15, 2003.

The Compensation Committee did not award Mr. McDonald shares of common stock from the Company's Restricted Stock Plan or options from the Company's Stock Option Plan.

Compensation Committee

Peter A. Leidel, Chairman
Cortlandt S. Dietler

David H. Kennedy

**Director Compensation**

Each of our directors who is neither an officer nor an employee will be paid a director's fee of $1,500 per quarter and $1,000 per committee meeting when the committee meeting is held separate from any regularly scheduled board meeting. Directors are also reimbursed for expenses incurred in attending Board of Directors and committee meetings, including expenses for travel, food and lodging.

On October 21, 2002, Messrs. Dietler, Kennedy and Trueblood were each granted non-qualified stock options to purchase 5,000 shares of Carbon common stock at $9.88 per share. Shares subject to these options vest one-third on the first, second and third anniversaries of the date of grant and have a ten year term.

**PERFORMANCE GRAPH**

The following performance graph compares the cumulative total stockholders' return for Carbon's common stock with the cumulative total return for the S&P 500 Index and the Dow Jones Secondary Oil Index commencing February 23, 2000 (the initial trading date for Carbon shares) and ending December 31, 2002. The closing sales price of the Company's common stock on the last trading day of 2002 was $10.00.

The table assumes that the value of an investment in Carbon common stock and each index was $100 on February 23, 2000 and that all dividends were reinvested. The stock price performance shown on the graph is not necessarily indicative of future price performance.

| | 02/23/00 | 12/31/00 | 12/31/01 | 12/31/02 |
|---|---|---|---|---|
| Carbon Energy Corproation | 100.0 | 123.0 | 158.0 | 182.0 |
| S&P 500 Index(1) | 100.0 | 97.0 | 84.0 | 65.0 |
| DJ Secondary Oil Index(2) | 100.0 | 179.0 | 162.0 | 164.0 |

(1) Source: Fact Set Research Systems, Inc.

(2) Source: Bloomberg

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

The following table contains information regarding ownership of our common stock (the only class of stock outstanding) as of June 30, 2003 by each director, each executive officer named in the compensation table, all of our directors and executive officers as a group, and each shareholder who, to our knowledge, was the beneficial owner of five percent or more of the outstanding shares. All information is based on information provided by such persons to us. Unless otherwise indicated, their addresses are the same as Carbon's address and each person identified in the table holds sole voting and investment power with respect to the shares shown opposite such person's name. Footnotes supplement the information contained in the table.

| Name and Address of Beneficial Owner | Amount and Nature of Beneficial Ownership(a) | Percent Outstanding |
|---|---|---|
| Patrick R. McDonald and McDonald Energy, LLC | 326,054(b)(c) | 5.1% |
| Kevin D. Struzeski | 69,999(d) | 1.1% |
| Cortlandt S. Dietler<br>P.O. Box 5660 | 31,666 | * |

| Name and Address of Beneficial Owner | Amount and Nature of Beneficial Ownership(a) | Percent Outstanding |
|---|---|---|
| Denver, CO 80217 | | |
| David H. Kennedy<br>23 Lakeside Avenue<br>Darien, CT 06820 | 31,666 | * |
| Bryan H. Lawrence<br>410 Park Avenue, Suite 1900<br>New York, NY 10022 | 4,500,000(e) | 71.8% |
| Peter A. Leidel<br>410 Park Avenue, Suite 1900<br>New York, NY 10022 | 4,500,000(f) | 71.8% |
| Harry A. Trueblood, Jr<br>1720 S. Bellaire Street<br>Suite 912<br>Denver, CO 80222 | 262,062(g) | 4.2% |
| All directors and executive officers as a group (7 persons including the above) | 5,221,447 | 81.1% |
| Yorktown Energy Partners III, L.P.<br>410 Park Avenue, Suite 1900<br>New York, NY 10022 | 4,500,000 | 71.8% |

* Less than 1%

(a) Includes the number of shares of common stock of the Company subject to stock options exercisable within 60 days after June 30, 2003, as follows: Mr. McDonald, 70,000 shares; Mr. Struzeski, 49,999 shares; Mr. Dietler, 21,666 shares; Mr. Kennedy, 21,666 shares and Mr. Trueblood, 1,666 shares; all directors and officers as a group, 164,997 shares.

(b) Includes 50,000 shares of restricted stock granted pursuant to the Company's 1999 restricted stock plan, 39,999 of which have vested, 3,334 of which vest in 2003, 3,333 of which vest in 2004 and 3,334 of which vest in 2005.

(c) Patrick R. McDonald is the sole member of McDonald Energy, LLC. The total includes 117,100 shares owned by CEC Resources Holdings, LLC of which McDonald Energy, LLC has a 58.3% interest.

(d) Includes 20,000 shares of restricted stock, 12,499 of which have vested, 834 of which vest in 2003, 2,499 of which vest in 2004, 2,501 of which vest in 2005 and 1,667 which vest in 2006.

(e) These shares are owned by Yorktown Energy Partners III, L.P. As a member of Yorktown Partners LLC, the manager of Yorktown Energy Partners III, L.P., Mr. Lawrence may be deemed to be a beneficial owner of these shares. Mr. Lawrence disclaims beneficial ownership of these shares.

(f) These shares are owned by Yorktown Energy Partners III, L.P. As a member of Yorktown Partners LLC, the manager of Yorktown Energy Partners III, L.P., Mr. Leidel may be deemed to be a beneficial owner of these shares. Mr. Leidel disclaims beneficial ownership of these shares.

(g) Does not include 35,711 shares which are owned by Lucile B. Trueblood, Mr. Trueblood's wife, which she acquired as her separate property and as to which Mr. Trueblood disclaims any beneficial ownership. Includes 12,000 shares owned by the Harry A. Trueblood, Jr. Charitable Remainder Unitrust dated June 1, 1998 as to which shares Mr. Trueblood disclaims ownership; however, as the only trustee, he does hold sole voting rights and dispositive powers with respect to such shares.

The following table provides as of December 31, 2002, information regarding the Company's equity compensation plans, which consists of the 1999 stock option plan and 1999 restricted stock plan.

| Plan Category | Number of securities to be issued upon exercise of outstanding options, warrants and rights (a) | Weighted-average exercise price of outstanding options, warrants and rights (b) | Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c) |
|---|---|---|---|
| **Equity compensation plans approved by security holders** | 570,168 | $ 5.87 | 290,568 |
| **Equity compensation plans not approved by security holders** | -0- | -0- | -0- |
| **Total** | 570,168 | $ 5.87 | 290,568 |

The number of shares of common stock remaining available for future issuance as shown in the table consists of 75,568 shares that may be subject to options granted in the future under the 1999 stock option plan and 215,000 shares of common stock available under the 1999 restricted stock plan.

As described in Item 1 of this report, Carbon has entered into an agreement and plan of reorganization with Evergreen Resources, Inc. under which Carbon will merge with a subsidiary of Evergreen and Carbon shareholders will receive 0.275 shares of Evergreen stock for each outstanding share of Carbon common stock (and cash in lieu of any fractional shares). Yorktown Energy Partners III, L.P. and Mr. McDonald, who at March 31, 2003 beneficially owned approximately 73.2% and 6.0%, respectively, of Carbon's outstanding common stock, have executed voting agreements with Evergreen obligating each of them to vote all shares over which the party has voting control in favor of the merger. Carbon expects the merger to close in the second quarter or third quarter of 2003.

## ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

In October 1999, Yorktown purchased an aggregate of 4,500,000 shares of our common stock for $24,750,000 in cash. On October 14, 1999, Carbon, CEC and Yorktown signed the Exchange and Financing Agreement that provided for:

- An assignment of the BFC stock purchase agreement to Carbon;
- The purchase of common stock of Carbon by Yorktown as described above;
- The exchange offer made for CEC shares;
- Persons to be nominated as directors of the Company;
- The adoption of the Company's 1999 stock option plan and the Company's 1999 restricted stock plan; and
- The Company's entering into employment agreements with Mr. McDonald and Mr. Struzeski.

In the Exchange Agreement, Carbon, CEC and Yorktown agreed that the Board of Directors of Carbon will consist of five directors. Carbon, CEC and Yorktown agreed that the five directors initially would be David H. Kennedy, a person who passed away and was replaced by Cortlandt S. Dietler, Bryan H. Lawrence, Peter A. Leidel and Patrick R. McDonald. After completion of the exchange offer and Harry A.

Trueblood, Jr.'s acceptance of the exchange offer for all CEC common stock beneficially owned by him, the number of Carbon directors was increased to six and Mr. Trueblood was elected as the sixth director. As long as Yorktown beneficially owns shares with 50% or more of the outstanding votes in the election of directors of Carbon, Yorktown has the right to designate for nomination two directors. If Yorktown beneficially owns shares with 25% or more but less than 50% of the outstanding votes in the election of directors of Carbon, then Yorktown has the right to designate for nomination one director. Yorktown has no right to designate directors for nomination under the Exchange Agreement if Yorktown beneficially owns shares with less than 25% of the outstanding votes in the election of directors of Carbon. So long as Mr. McDonald is an officer of Carbon, he is to be designated for nomination as a director of Carbon.

As provided by the Exchange Agreement, a Nominating Committee of Carbon's Board was established. The Nominating Committee consists of one Yorktown designated director, Mr. McDonald so long as he is a director of Carbon, and two independent directors. The Nominating Committee is responsible for determining nominees for the positions of directors of Carbon or persons to be elected by the Board of Directors or shareholders of Carbon to fill any vacancy in the Board of Directors. The Nominating Committee is required to nominate for director each Yorktown director which Yorktown has the right to designate and has designated. The Nominating Committee is required to nominate Mr. McDonald if he is entitled to be nominated. The Nominating Committee will then nominate the remaining directors; at least two of the persons nominated will be independent directors. If the size of the Board is changed and there are not sufficient positions for the election of two independent directors after taking into account the directors designated by Yorktown and Mr. McDonald, then the Nominating Committee is not required to nominate two independent directors. If there is a vacancy in the position relating to a Yorktown director, the remaining Yorktown director has the right to designate any replacement to fill the vacancy. The Nominating Committee has the right to designate any replacement to fill any other vacancy. The Exchange Agreement requires that any change in the size or composition of the Board of Directors or the Nominating Committee be approved by a supermajority vote of the Board consisting of a majority of the entire Board which includes a majority of all Yorktown directors and at least one independent director. The Exchange Agreement requires that Yorktown and Mr. McDonald take such actions as shareholders of Carbon as necessary to effectuate the election of directors nominated pursuant to the foregoing provisions. The provisions relating to election of directors cease to be effective on October 29, 2009 or, if earlier, when Yorktown beneficially owns shares with less than 25% of the outstanding votes in the election of directors and Mr. McDonald is no longer an officer of Carbon.

On July 22, 1999, Mr. McDonald was granted a 20,000 share non-qualified option at a strike price of $4.25. The expiration date for these options was July 21, 2002. Due to non-public information prior to and at the expiration date, the sale of the shares subject to these options may have been prohibited. To facilitate the exercise of the options, the entire Board, exclusive of Mr. McDonald, authorized the cancellation of the options and a cash payment equal to the stock appreciation amount of $108,160. The appreciation amount was the difference per share between the exercise price of the options and the fair market value of the underlying stock on the date of cancellation. Concurrent with the cash payment, and with approval of the entire Board exclusive of Mr. McDonald,

Carbon purchased 5,267 shares of Carbon common stock from Mr. McDonald at the market price of $9.65 per share for a total of $50,827.

## ITEM 14 CONTROLS AND PROCEDURES

Within the 90 days prior to the date of this report, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including Carbon's principal executive officer and principal financial officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-14 under the Securities Exchange Act of 1934. Based upon that evaluation, the principal executive officer and principal financial officer concluded that the Company's disclosure controls and procedures are effective for purposes of recording, summarizing and timely reporting material information required to be disclosed in reports that the Company files under the Securities Exchange Act of 1934. There were no significant changes in the Company's internal controls or in other factors that could significantly affect these controls since the date the controls were evaluated.

# PART IV

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

(a)

(1) Financial Statements:

See indexes to Financial Statements of Carbon in Item 8.

Schedules are omitted because of the absence of the conditions under which they are required or because the information is included in the Consolidated Financial Statements or notes to the Consolidated Financial Statements.

(b) Reports on Form 8-K:

The following report was filed by the Company on Form 8-K during the quarter ended December 31, 2002: None.

(c) Exhibits:

| Exhibit Number | Description of Exhibit |
|---|---|
| 3.1 | Articles of Incorporation of Carbon Energy Corporation, incorporated by reference to Exhibit 2 of the Company's registration statement on Form S-4, No. 333-89783, effective January 18, 2000. |
| 3.2 | Bylaws of Carbon Energy Corporation, incorporated by reference to Exhibit 3 of the Company's registration statement on Form S-4, No. 333-89783, effective January 18, 2000. |
| 10.1 | 1999 Stock Option Plan, incorporated by reference to Exhibit 10.1 of the Company's registration statement on Form S-4, No. 333-89783, effective January 18, 2000. |
| 10.2 | 1999 Restricted Stock Plan, incorporated by reference to Exhibit 10.2 of the Company's registration statement on Form S-4, No. 333-89783, effective January 18, 2000. |
| 10.3 | Exchange and Financing Agreement dated October 14, 1999 among Carbon Energy Corporation, Carbon Canada Resources Ltd. and Yorktown Energy Partners III, L.P., incorporated by reference to Exhibit 10.3 of the Company's registration statement on Form S-4, No. 333-89783, effective January 18, 2000. |
| 10.4 | Stock Purchase Agreement dated August 11, 1999 between Bonneville Pacific Corporation and Carbon Canada Resources Ltd., incorporated by reference to Exhibit 10.4 of the Company's registration statement on Form S-4, No. 333-89783, effective January 18, 2000. |
| 10.5 | Form of Indemnification Agreement between Carbon Energy Corporation and its officers and directors, incorporated by reference to Exhibit 10.5 of the Company's registration statement on Form S-4, No. 333-89783, effective January 18, 2000. |
| 10.6 | Employment Agreement, dated as of October 29, 1999, between Carbon Energy Corporation and Patrick R. McDonald, incorporated by reference to Exhibit 10.6 of the Company's registration statement on Form S-4, No. 333-89783, effective January 18, 2000. |
| 10.7 | Employment Agreement, dated as of October 29, 1999, between Carbon Energy Corporation and Kevin D. Struzeski, incorporated by reference to Exhibit 10.7 of the Company's registration statement on Form S-4, No. 333-89783, effective January 18, 2000. |
| 10.8 | Credit agreement dated as of May 9, 2002 between CEC Resources Ltd. and Canadian Imperial Bank of Commerce, incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q No. 1-15639, filed August 19, 2002. |
| 10.9 | Amended and restated credit agreement dated December 31, 2002 between Carbon Energy Corporation (USA) and Bank of Oklahoma, National Association.** |
| 10.10 | Asset purchase and sale agreement dated January 15, 2003 by and between Carbon Energy Corporation (USA), formerly known as Bonneville Fuels Corporation as Seller and Fasken Acquisition 02, Ltd. as Buyer.** |
| 10.11 | First amendment to asset purchase and sale agreement, dated March 19, 2003 by and between Carbon Energy Corporation (USA), formerly known as Bonneville Fuels Corporation as |

| | |
|---|---|
| | Seller and Fasken Acquisition 02, Ltd. as Buyer.** |
| 10.12 | Employment Agreement dated October 1, 2002 between Carbon Energy Corporation and Patrick R. McDonald |
| 21 | List of subsidiaries** |
| 23.1 | Consent of KPMG LLP** |
| 23.2 | Consent of Ryder Scott Company, L.P.** |
| 23.3 | Consent of Sproule Associates Limited** |
| 24 | Power of Attorney** |
| 99.1 | Certificate of 10-K/A Report, dated September 15, 2003, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.* |

* Filed or furnished herewith

** Previously filed with this Report

## SIGNATURES

Pursuant to the requirements of Section 13 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.
Date: September 15, 2003

CARBON ENERGY CORPORATION

By: /s/ PATRICK R. MCDONALD

Patrick R. McDonald, *President and Chief Executive Officer*

By: /s/ KEVIN D. STRUZESKI

Kevin D. Struzeski, *Treasurer and Chief Financial Officer*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons of the Registrant and in the capacities and on the dates indicated:

| Date | Name and Title | | Signature |
|---|---|---|---|
| September 15, 2003 | Cortlandt S. Dietler, Director | ) ) ) | /s/ PATRICK R. MCDONALD |
| September 15, 2003 | David H. Kennedy, Director | ) ) ) | Patrick R. McDonald, for himself and as Attorney-in-Fact for the named directors who together constitute all |

| Date | Name and Title | | Signature |
|---|---|---|---|
| September 15, 2003 | Bryan H. Lawrence,<br>Director | )<br>)<br>) | of the members of Registrant's Board<br>of Directors |
| September 15, 2003 | Peter A. Leidel,<br>Director | )<br>)<br>) | |
| September 15, 2003 | Patrick R. McDonald,<br>Director | )<br>)<br>) | |
| September 15, 2003 | Harry A. Trueblood, Jr.,<br>Director | )<br>) | |

**CERTIFICATIONS**

I, Patrick R. McDonald, certify that:

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

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

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

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

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

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

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

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

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

   b.

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

6. The registrant's other certifying officer and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: September 15, 2003

/s/ PATRICK R. MCDONALD

Patrick R. McDonald
*President and Chief Executive Officer*

**CERTIFICATIONS**

I, Kevin D. Struzeski, certify that:

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

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

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

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

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

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

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

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

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

   b.

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

6. The registrant's other certifying officer and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: September 15, 2003

/s/ KEVIN D. STRUZESKI

Kevin D. Struzeski
*Treasurer and Chief Financial Officer*

**EXHIBIT INDEX**

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