2003

Quicksilver Resources Inc

FINANCIAL HIGHLIGHTS

In thousands, except per share, production and product price data

	2003	2002	2001	2000	1999
Revenues	**$140,949**	$ 121,979	$ 141,963	$ 118,392	$ 49,913
Income before income taxes	**$ 28,502**	$ 21,333	$ 30,110	$ 27,731	$ 3,023
Net Income	**$ 16,208**	$ 13,835	$ 19,310	$ 17,618	$ 3,162
Net Income per Diluted Share	**$ .71**	$ .68	$ 1.00	$ .95	$ .24
Diluted Weighted Avg. Number of Shares Outstanding for the Periods	**22,845**	20,394	19,221	18,467	13,151
Total Assets	**$666,934**	$ 529,538	$ 471,884	$ 440,111	$ 194,302
Long-Term Debt	**$249,097**	$ 248,493	$ 248,425	$ 239,986	$ 94,952
Total Stockholders' Equity	**$241,816**	$ 128,905	$ 94,387	$ 86,758	$ 69,551
Natural Gas & NGL Production (Mmcfe)	**35,346**	33,781	33,859	27,621	16,700
Average Price per Mcf	**$ 3.38**	$ 2.74	$ 3.04	$ 3.08	$ 2.22
Crude Oil Production (MBbl)	**808**	905	1,059	1,035	724
Average Price per Bbl	**$ 24.23**	$ 21.74	$ 21.03	$ 22.87	$ 14.55

Company Profile

Fort Worth, Texas-based Quicksilver Resources is a natural gas and crude oil production company engaged in the development and acquisition of long-lived producing natural gas and crude oil properties. The company, widely recognized as a leader in the development and production of unconventional natural gas reserves, including coalbed methane, shale gas, and tight sands gas, is listed on the New York Stock Exchange (KWK).

KWK
LISTED
NYSE

Table of Contents

Investor Inquiries and Requests

For more information about Quicksilver or for copies of press releases, reports, or other corporate information, please contact Investor Relations at our corporate headquarters, by phone at (817) 665-5000, by fax at (817) 665-5004, or by email at quicksilver@qrinc.com.

About the Cover: Cover photo courtesy of Alberta Photo Company.

Letter to Shareholders

2003 marked another year of strong advancement for Quicksilver Resources. After spending a significant percentage of the company's capital budget over the last two years identifying, testing, and proving new unconventional gas projects, Quicksilver began posting the results in 2003. Production from both our coalbed methane development in southern Alberta and our fractured shale project in Indiana and Kentucky is growing significantly and will multiply our reserve base over the next several years.

Our concentration on unconventional gas resources is paying off, and the Quicksilver team has sharpened its skills in quantifying and developing these types of reservoirs. This has resulted in a large drill site inventory and puts Quicksilver at the top of the list of companies with double-digit growth rates generated by drilling. Due to declining production and increasing finding and development costs in our industry, we expect our inventory of locations will increase in value as we go forward.

Quicksilver currently has drilling rights on over 1,300,000 net acres. Included in this number are 110,000 acres in a new company project, the Barnett Shale in north central Texas. Production from this formation has made the Barnett Shale play the largest producing gas field in Texas. As in many of our other unconventional projects, Quicksilver is using technological advancements to access commercial quantities of gas in this tight shale formation. The particular technological breakthrough in this play has been the drilling and fracture stimulation of horizontal wellbores. Having recently brought our first gas on stream from this project, we are now producing unconventional gas in four different geological basins. This certainly distinguishes Quicksilver from our industry peers and is affirmation that our business strategy is working. It is gratifying to see all areas of the company contributing to increased value for our shareholders. Michigan has provided the solid base of production and cash flow which has enabled new projects to come on line. In the northern Rockies, we continue to pursue shallow gas projects, and the steady oil production from that region supports the effort. Behind all of this is a dedicated team of employees working hard to achieve the company's goals. It is a pleasure to work with such a fine and talented group.

Quicksilver recently marked its fifth anniversary as a public company. The growth in assets and the value creation for our shareholders over those five years has been significant. The company continues to achieve milestones, and the next one in sight is reaching one trillion cubic feet of gas equivalents in reserves. With the projects in hand, we expect to be there shortly.

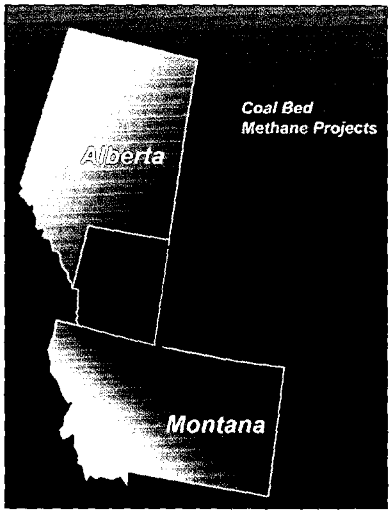
Our board of directors has kept us on course, and we thank them for all of their contributions. We also thank our shareholders for their continued support.

It is an exciting year for Quicksilver as we will drill more wells than in any previous year. We look forward to reporting our results and progress.

Very truly yours,

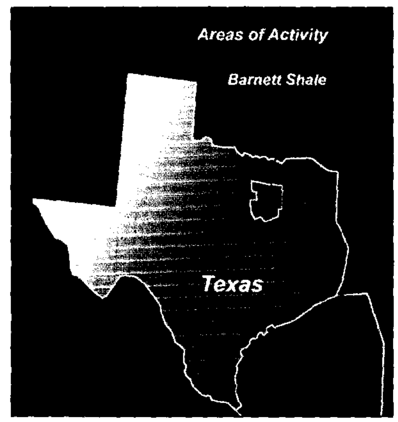
Thomas F. ("Toby") Darden
Chairman

Glenn Darden
President and CEO



very rare for this type of production. Because water disposal facilities are not required, capital expenditures are greatly reduced, and operating costs are less on an ongoing basis. As a result, this project is very cost efficient and profitable. These reservoirs typically have a slow decline rate and a reserve life of more than 20 years. MGV plans to drill approximately 280 net coalbed wells in 2004.

Texas – Barnett Shale



The company's newest unconventional gas project is in the Barnett Shale play in North Texas – the largest producing gas field in the state of Texas. This fractured shale is approximately 350 feet thick and occurs at a depth between 7,000 and 8,000 feet. Technology has increased the size of the original production fairway. Most of the new wells are drilled horizontally to access more fractured shale and avoid an underlying water zone (Ellenberger). In the northern portion of the play area or the core area, a limestone formation (Viola) at the base of the Barnett shale acts as a natural fracture stimulation barrier for the traditional vertical wells. New technology using horizontal well bores for drilling and completing is now producing successful wells in areas where the limestone barrier does not exist.

Quicksilver has assembled 110,000 net acres to pursue an active drilling program in the Barnett Shale. The company is flowing commercial gas from two third-party operated wells and is planning to drill an additional five Quicksilver operated wells in 2004.

LEADING IN PROCESSES

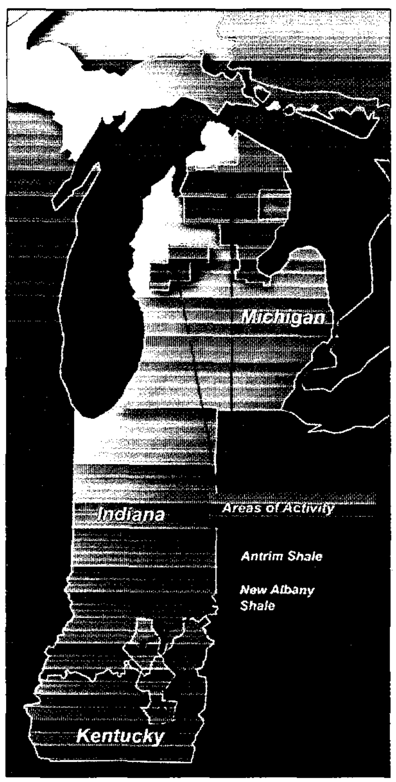
Just as the name implies, unconventional reservoirs do not respond to the same techniques and recovery methods typically used in the recovery of gas in conventional reservoirs. New strategies and new concepts are being applied every day to the exploration, drilling and completion of these types of

LEADING IN PRESENCE

With the commonly reported projections that consumption of natural gas will continue to increase in North America, as well as throughout the developing world, the energy industry will need to turn to unconventional sources for natural gas. Quicksilver Resources is positioned to help meet this growing need with its focus on unconventional sources such as fractured shales and coal seams.

What is unconventional gas? Historically the distinction between conventional gas and unconventional gas was based on economics. Marginally economic gas resources, known as unconventional, included low permeability reservoirs, including tight sands, shales, and coalbeds. With new technology and favorable gas prices, many of these previously uneconomic resources are now highly profitable.

Approximately 75 percent of Quicksilver Resources' current production comes from coal and fractured shale production. The remaining 25 percent comes from conventional production. Quicksilver Resources is currently producing unconventional gas in Michigan, Indiana, Texas and Canada.



Michigan – Antrim Shale

Quicksilver Resources' most mature development project is in the Antrim Shale formation in Michigan where the company has grown production over the past 13 years. It is a long life gas reservoir which is the solid foundation of Quicksilver's reserves and production base. The company drilled 55 net wells in 2003 and plans to drill 51 net wells in 2004.

Indiana/Kentucky – New Albany Shale

Quicksilver's unconventional gas production in Indiana comes from the New Albany Shale, a formation of the same geologic age and characteristics as the Antrim. This project is in the early stages of development, and the company expects it to become a significant contributor to its production and reserves over the next several years. Quicksilver drilled 90 net wells in 2003 and will drill 58 net wells in 2004.

Alberta, Canada – Edmonton Coals

Coalbed methane (CBM) is produced by Quicksilver through its Canadian subsidiary, MGV Energy Inc. (MGV), in southern and central Alberta, Canada. The natural gas found in these coals is the cleanest-burning fossil fuel and is often pure enough to be delivered directly into the pipeline with little or no processing. The company has drilled more than 200 net wells to date with typical wells averaging 140 Mcf per day. The Horseshoe Canyon member of the Edmonton group of coals is virtually water-free, which is

As the Future of Unconventional Gas Development

2003

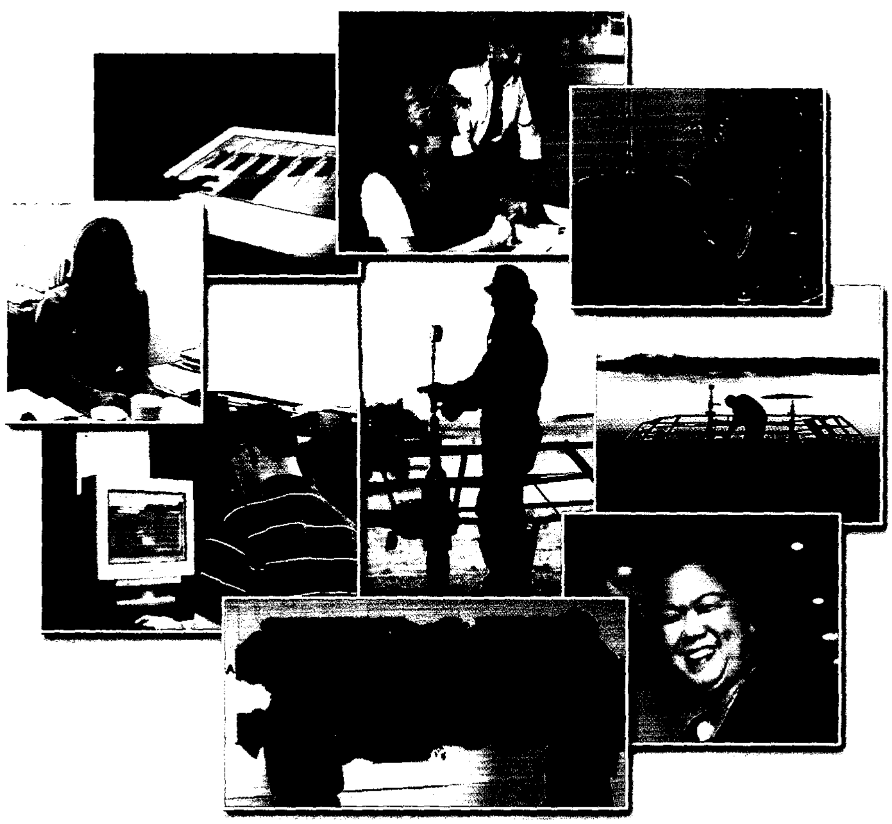
UNFOLDS,
QUICKSILVER
RESOURCES IS
POSITIONED TO LEAD.

LEADING IN PEOPLE

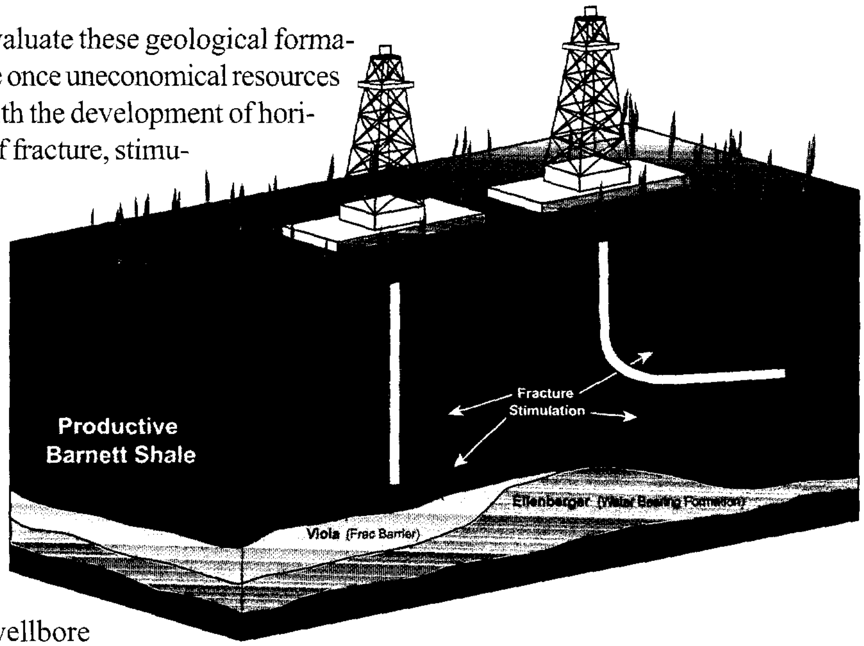
Quicksilver Resources' employees are the reason for our ongoing success. We have grown from a start of 15 employees in 1999 to more than 300 employees today. Quicksilver was founded by a team with extensive experience and knowledge of the oil and gas business. However, to manage the company's rapid growth, we have made additions in all areas of expertise including Engineering, Geology, Land, Operations, Safety, Environment, Legal, Accounting, Information Services, Human Resources, and Internal Audit. Quicksilver is very successful in attracting and retaining individuals who are highly skilled and embrace the company's growth vision.

The working environment at Quicksilver encourages open communication and cooperation without rigid departmental boundaries. Team members seek out the opinions and experience of others and offer to lend a hand to provide support with every task that must be completed to meet company goals.

Effective communication facilitates the transfer of information between producing areas while building on the experience gained in each unconventional gas field. Our culture leads to the dedication and commitment of all employees, which fuels Quicksilver Resources' ongoing growth and success.



wells. The technology used to evaluate these geological formations is constantly evolving. These once uneconomical resources have now become commercial with the development of horizontal drilling and the evolution of fracture, stimulation, and production techniques.

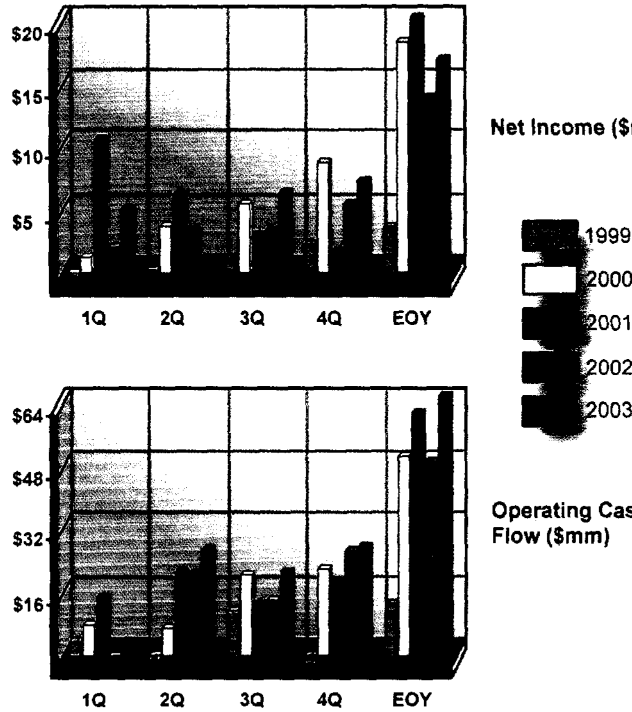


The advancement of seismic processing over the past few years has provided better tools to identify the location of hydrocarbons and increased the understanding of the fractures, location of water, and properties of the rock. Once a potential location has been identified, horizontal wells can now be used to target specific zones. In a horizontal well, the wellbore extends laterally through the zone and allows the fracture stimulation to travel vertically. Another technique which has recently emerged is "oriented perforating." By using a magnet at the end of the wellbore, an operator can steer the perforations or control the direction of the blasts into the casing and target a specific fracture for stimulation. The application of the best technology available to specific formations allows Quicksilver to recover more of the current gas in place and to expand the limits of each field.

LEADING IN POTENTIAL

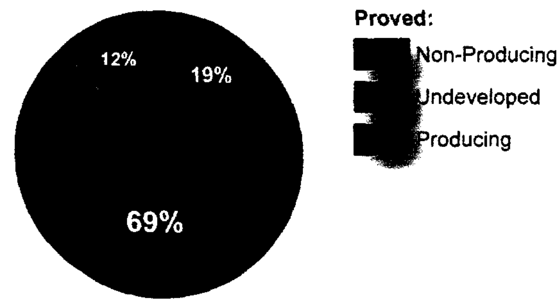
Quicksilver Resources has established itself as an industry leader with attractive growth potential due to its proven ability to identify and develop unconventional gas production for the future. We are excited about the potential of our significant drill site inventory. By combining our large acreage position with our experienced team and the advancement of technology, Quicksilver is planning to drill approximately 400 net wells in 2004. We have a business model that is working, and we believe that we can continue to expand into new areas of operation.

Reserves and Historical Data

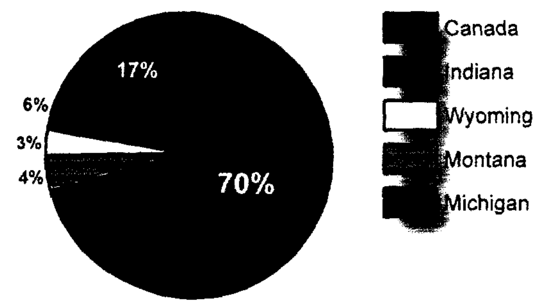


Net Income ($mm)

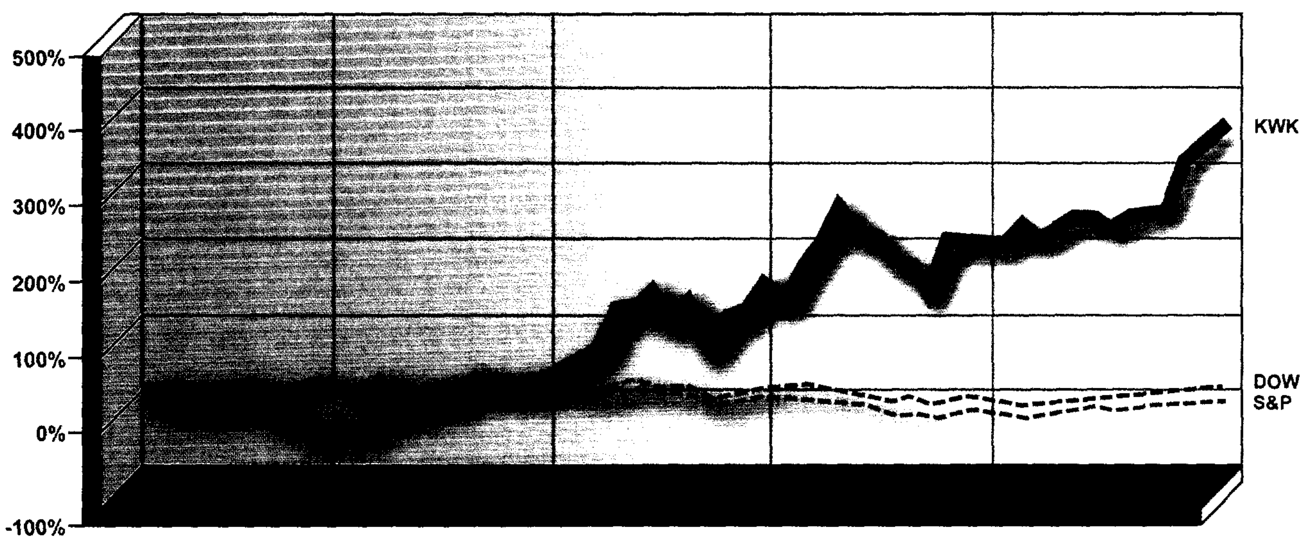
Operating Cash Flow ($mm)



Reserves By Category



Reserves By Location



KWK Stock Information

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2003

OR

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

For the transition period from _____ to _____.

Commission file number: 001-14837

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

Delaware	**75-2756163**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

777 West Rosedale, Suite 300,
Fort Worth, Texas 76104
(Address of principal executive offices) (Zip Code)
Registrant's telephone number, including area code: (817) 665-5000

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.01 per share	New York Stock Exchange

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

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

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

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

As of June 30, 2003, the aggregate market value of the voting stock held by non-affiliates of Quicksilver Resources Inc. was approximately $259,901,376 based on the New York Stock Exchange composite trading closing price of $23.95 on June 30, 2003, and using the definition of beneficial ownership contained in Rule 16a-1(a) (2) promulgated pursuant to the Securities Exchange Act of 1934.

As of March 1, 2004, 24,821,406 shares of common stock of Quicksilver Resources Inc. were outstanding.

Documents incorporated by reference: Proxy statement of the registrant relating to the annual meeting of stockholders to be held on May 18, 2004 which is incorporated into Part III of this Form 10-K.

INDEX TO ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2003

Except as otherwise specified and unless the context otherwise requires, references to the "Company," "Quicksilver," "we," "us," and "our" refer to Quicksilver Resources Inc. and its subsidiaries.

Quantities of natural gas are expressed in this report in terms of thousand cubic feet ("Mcf"), million cubic feet ("MMcf") or billion cubic feet ("Bcf"). Crude oil and natural gas liquids are quantified in terms of barrels ("Bbl"), thousands of barrels ("MBbl") or millions of barrels ("MMBbl"). Crude oil and natural gas liquids are compared to natural gas in terms of thousands of cubic feet of natural gas equivalent ("Mcfe"), millions of cubic feet of natural gas equivalent ("MMcfe") or billions of cubic feet of natural gas equivalent ("Bcfe"). One barrel of crude oil or natural gas liquids is the energy equivalent of six Mcf of natural gas. Natural gas volumes also may be expressed in terms of one million British thermal units ("MMBtu"), which is approximately equal to one Mcf. Daily natural gas and crude oil production is signified by the addition of the letter "d" to the end of the terms defined above. With respect to information relating to working interests in wells or acreage, "net" natural gas and crude oil wells or acreage is determined by multiplying gross wells or acreage by the working interest we own. Unless otherwise specified, all reference to wells and acres are gross.

PART I

ITEM 1. Business

We are an independent oil and gas company engaged in the exploration, acquisition, development, production and sale of natural gas, crude oil and natural gas liquids ("NGLs") primarily from unconventional reservoirs such as fractured shales, coal beds and tight sands. Mercury Exploration Company ("Mercury"), which made significant contributions of properties to us at the time of our formation, was founded by Frank Darden in 1963 to explore and develop conventional oil and gas properties in the United States. We are a Delaware corporation and became a public company in 1999 through a merger with MSR Exploration Ltd. ("MSR"). The Darden family, including Mercury and another entity controlled by the Dardens, still retains a significant ownership position in us, with approximately 38% beneficial ownership as of December 31, 2003. Thomas Darden, Glenn Darden and Anne Darden Self serve on our Board of Directors along with five independent directors. Thomas Darden is Chairman of our Board, Glenn Darden is our President and Chief Executive Officer and Anne Darden Self is our Vice President-Human Resources.

Our operations are concentrated in Michigan, Indiana, the Rocky Mountains and the Canadian province of Alberta. At December 31, 2003, we had estimated proved reserves of 881 Bcfe. Approximately 90% of our reserves were natural gas, 81% were classified as proved developed and we operated approximately 73% of our reserves. Approximately 70% of our estimated proved reserves are located in Michigan and are characterized by long reserve lives and predictable well production profiles. For 2004, our focus will be the exploration and development of coal bed methane reserves in Alberta, Canada. We believe that much of our future growth will be through exploration and development of our interests in these Canadian coal bed methane projects. Our newest acreage position is located in North Central Texas where we will be testing and evaluating the Barnett Shale formation during 2004.

We intend to maintain an active capital spending program that will be focused primarily on the continued development and exploitation of our properties in Michigan and Indiana, as well as development and exploratory spending in support of our coal bed methane operations in Canada. For 2004, we have established a company-wide capital budget of $157 million of which approximately $45 million will be allocated for compression and gathering systems. In geographic terms, we anticipate that 43% of the total capital budget will be allocated to our United States operations and 57% will be allocated to our Canadian operations.

The following table presents information regarding our primary areas of operation as of December 31, 2003:

Areas of Operations	Proved Reserves (Bcfe)	% Natural Gas	% Proved Developed	2003 Production (MMcfed)
Michigan	619.7	95%	89%	92.2
Canada	146.6	100%	57%	8.0
Indiana	48.4	100%	76%	2.4
Other	66.0	8%	64%	7.5
Total	880.7	90%	81%	110.1

Several important transactions have provided the basis for our growth. On December 2, 2002, we purchased from Enogex Exploration Corporation its interests in natural gas properties located in Michigan, most of which we have operated and continue to operate. We acquired approximately 64.2 Bcfe of estimated proved reserves for approximately $32.0 million ($28.7 million after closing adjustments). The purchased interests added production of approximately 8.4 MMcfd of natural gas. We financed the acquisition with available cash and existing credit facilities.

We conduct our Canadian operations through our wholly owned subsidiary, MGV Energy Inc. ("MGV"). Shortly after we completed our acquisition of MGV in 2000, we entered into a joint venture with EnCana

Corporation to explore for coal bed methane ("CBM") reserves on an area of over three million acres of land. In January 2003, MGV entered into an asset rationalization agreement with EnCana to divide the assets and rights subject to the joint venture and allow us to pursue independent operations. As a result of the agreement, MGV received an interest or an option to drill and earn in approximately 667,000 acres of Alberta land where we are conducting a variety of CBM projects. MGV acquired an additional 50% working interest in 76,800 acres in the Wood River area south of Edmonton, Alberta in January 2004 for $5.4 million from Ice Energy Limited. As a result, MGV now owns a 100% working interest in these lands.

Net gas sales from our initial CBM development projects, in the Gayford and Beiseker areas of the West Palliser block plus several single-well tie-ins outside the West Palliser block, averaged 5.8 MMcfd in 2003. By year-end, production from our CBM projects was 16 MMcfd. Negligible water volumes have been experienced in these areas, precluding the need for water handling facilities. We have connected these wells into existing infrastructure and pipeline systems to assure the control and priority of natural gas sales. As of December 31, 2003, we have 131.3 Bcf of proved reserves from our CBM projects in addition to 15.3 Bcf of proved reserves from our other Canadian natural gas interests.

Our 12-mile Cardinal Pipeline was placed into service at the end of September 2003. The Cardinal Pipeline transports our Indiana production to an interstate pipeline market in Kentucky. Including sales to a local end-user, we are now selling approximately 5.7 MMcfd, net from the New Albany shale production area. Including the 90 wells drilled and the 35 wells acquired from Aurora Energy Ltd. ("Aurora") in 2003, we have 190 total wells and 48.4 Bcf of proved reserves from our New Albany shale area. Production from approximately 24 of the 35 non-producing wells acquired from Aurora, located in north Harrison County, is expected to be reestablished in the first quarter of 2004.

Business Strategy

Our business strategy is designed to achieve our principal objectives of growth in reserves, production and cash flow to increase stockholder value. Key elements of our business strategy include:

Focus on Unconventional Natural Gas Reserves. We focus our exploration and development efforts on unconventional natural gas reservoirs. Unconventional reservoirs such as natural gas produced from fractured shales, coal beds and tight sands will not produce at commercial flow rates unless the formation is successfully stimulated with fracturing. The majority of our Michigan production is from the Antrim Shale where we, and Mercury prior to our formation, have been active drillers and producers for over twelve years. Our Antrim Shale activities have allowed us to develop a technical and operational expertise in the acquisition, development and production of unconventional natural gas reserves. Our Canadian CBM and Indiana New Albany Shale projects represent an extension of our expertise in unconventional natural gas reserves.

Low-Cost Development of Existing Property Base. We attempt to increase production and reserves through aggressive management of operations and relatively low-risk development drilling. From 2001 to 2003, our all-sources finding cost was $0.77 per Mcfe computed by dividing exploration, development and acquisition capital expenditures, plus unevaluated expenditures as of December 31, 2000, less unevaluated expenditures as of December 31, 2003, by net reserve additions for the periods 2001 to 2003. Our principal properties possess geological and reservoir characteristics that make them well suited for production increases through exploitation activities and development drilling. We perform workovers and infrastructure improvement projects to reduce operating costs and increase current and ultimate production. We regularly review operations and mechanical data on operated properties to determine if additional actions can profitably be taken to increase reserves and production.

Pursuit of Selective Complementary Acquisitions. We seek to acquire long-lived producing properties with a high degree of operating control that contain opportunities to profitably increase natural gas and crude oil reserves and production levels through exploitation. Our reservoir enhancement techniques include the implementation of technically advanced reservoir management and aggressive cost management of field operations. We target acreage that we believe will expose us to high potential prospects located in areas that are geologically similar to neighboring areas with large developed fields. Consistent with our primary operating strategy, our acquisition focus is on unconventional reserves, including additional interests in properties we currently operate. Our significant operating position in Michigan uniquely positions us for further consolidation in that state through acquisitions that would provide additional economies of scale.

Management of Commodity Price Risk. We are focused on growing our oil and gas operations while seeking to minimize the effect of commodity price swings on net income and cash flow from operations. Our commodity price risk management strategy helps to ensure a predictable base level of cash flow, which enhances our ability to execute our drilling and exploitation programs, meet debt service requirements and pursue acquisition opportunities despite price fluctuations. To help ensure a level of predictability in the prices received for our natural gas and crude oil production, we have entered into natural gas sales contracts with price floors and natural gas and crude oil financial hedges. The sales contracts and financial hedges currently in effect covered approximately 71% and 73% of our daily natural gas and crude oil production, respectively, or 69% of our total daily production, for the fourth quarter of 2003. As our fixed price natural gas hedges terminate in 2004 and 2005, we expect to modify our hedging programs. We anticipate that those programs will make use of hedges with terms generally no longer than 12 to 18 months and that allow us to realize a portion of any market increases in natural gas or crude oil prices over their term.

Participation in Exploratory Drilling Projects. We will continue to focus the bulk of our activities on lower risk exploitation activity and development drilling, including future activities in Canada. However, we are allocating approximately 17% of 2004 capital expenditures to target high potential projects with higher levels of financial risk. These projects include additional exploratory drilling in Canada, testing and evaluating the Barnett Shale formation in North Central Texas, and pursuing additional leasehold acquisitions and joint venture opportunities aimed at providing us with opportunities to explore for unconventional gas, including fractured shales, coal beds and tight sands, to which our technical and operational expertise is well suited.

Marketing

Through December 2003, the natural gas produced from our domestic properties was marketed for us by Cinnabar Energy Services & Trading, LLC, our wholly-owned subsidiary, under long-term sales contracts and short-term wholesale spot market sales. Cinnabar also bought natural gas from and provided marketing services for third party producers. Of the total natural gas volumes marketed by Cinnabar, approximately 83% was attributable to natural gas production from leases in which Quicksilver owns an interest with the remainder produced from leases where we have no ownership interest. Cinnabar ceased its operations as of January 1, 2004.

We sell natural gas and crude oil to a variety of customers, including utilities, major oil and gas companies or their affiliates, industrial companies, large trading and energy marketing companies, refineries and other users of petroleum products, and we are not dependent upon one purchaser or a small group of purchasers. Accordingly, the loss of a single purchaser in areas in which we sell natural gas or crude oil would not materially affect our sales. During 2003, the two largest purchasers of our total consolidated natural gas and crude oil sales were Sempra Energy and CoEnergy Trading Company.

Competition

We encounter substantial competition in acquiring oil and gas leases and properties, marketing natural gas and crude oil, securing personnel and conducting our drilling and field operations. Many competitors have financial and other resources, which substantially exceed ours. The competitors in development, exploration, acquisitions and production include the major oil and gas companies as well as numerous independents and individual proprietors. Resources of our competitors may enable them to pay more for desirable leases and to evaluate, bid for and purchase a greater number of properties or prospects. Our ability to replace and expand our reserve base is dependent upon our ability to select and acquire suitable producing properties and prospects for future drilling.

Our acquisitions have been financed primarily through the issuance of debt and equity and internally generated cash flow. There is competition for capital to finance oil and gas acquisitions and drilling. Our ability to obtain such financing is uncertain and can be affected by numerous factors beyond our control. The inability to raise capital in the future could have an adverse effect on our business.

Governmental Regulation

Our operations are affected from time to time in varying degrees by political developments and United States and Canadian federal, state, provincial and local laws and regulations. In particular, natural gas and crude oil production and related operations are, or have been, subject to price controls, taxes and other laws and regulations relating to the industry. Failure to comply with such laws and regulations can result in substantial penalties. The regulatory burden on the industry increases our cost of doing business and affects our profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted so we are unable to predict the future cost or impact of complying with such laws and regulations.

Environmental Matters

Our natural gas and crude oil exploration, development, production and pipeline gathering operations are subject to stringent United States and Canadian federal, state, provincial and local laws governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental agencies, such as the Environmental Protection Agency ("EPA"), issue regulations to implement and enforce such laws, and compliance is often difficult and costly. Failure to comply may result in substantial costs and expenses, including possible civil and criminal penalties. These laws and regulations may:

- require the acquisition of a permit before drilling commences;
- restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production, processing and pipeline gathering activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, frontier and other protected areas;
- require remedial action to prevent pollution from former operations such as plugging abandoned wells; and
- impose substantial liabilities for pollution resulting from operations.

In addition, these laws, rules and regulations may restrict the rate of natural gas and crude oil production below the rate that would otherwise exist. The regulatory burden on the industry increases the cost of doing business and consequently affects our profitability. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, disposal or clean-up requirements could adversely affect our operations and financial position, as well as the industry in general. While we believe that we are in substantial compliance with current applicable environmental laws and regulations, and we have not experienced any materially adverse effect from compliance with these environmental requirements, we cannot assure you that this will continue in the future.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the present or past owners or operators of the disposal site or sites where the release occurred and the companies that transported or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damages allegedly caused by the release of hazardous substances or other pollutants into the environment. Furthermore, although petroleum, including natural gas and crude oil, is exempt from CERCLA, at least two courts have ruled that certain wastes associated with the production of crude oil may be classified as "hazardous substances" under CERCLA and thus such wastes may become subject to liability and regulation under CERCLA. State initiatives to further regulate the disposal of crude oil and natural gas wastes are also pending in certain states, and these various initiatives could have adverse impacts on us.

Stricter standards in environmental legislation may be imposed on the industry in the future. For instance, legislation has been proposed in Congress from time to time that would reclassify certain exploration and production wastes as "hazardous wastes" and make the reclassified wastes subject to more stringent handling, disposal and clean-up restrictions. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as on the industry in general. Compliance with environmental requirements generally could have a materially adverse effect upon our capital expenditures, earnings or competitive position. Although we have not experienced any materially adverse effect from compliance with environmental requirements, we cannot assure you that this will continue in the future.

The Federal Water Pollution Control Act ("FWPCA") imposes restrictions and strict controls regarding the discharge of produced waters and other petroleum wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters. The FWPCA and analogous state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of crude oil and other hazardous substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. Federal effluent limitations guidelines prohibit the discharge of produced water and sand, and some other substances related to the natural gas and crude oil industry, into coastal waters. Although the costs to comply with zero discharge mandated under federal or state law may be significant, the entire industry will experience similar costs and we believe that these costs will not have a materially adverse impact on our financial condition and results of operations. Some oil and gas exploration and production facilities are required to obtain permits for their storm water discharges. Costs may be incurred in connection with treatment of wastewater or developing storm water pollution prevention plans.

The Resource Conservation and Recovery Act ("RCRA"), generally does not regulate most wastes generated by the exploration and production of natural gas and crude oil. RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy." However, these wastes may be regulated by the EPA or state agencies as solid waste. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, are regulated as hazardous wastes. Although the costs of managing solid hazardous waste may be significant, we do not expect to experience more burdensome costs than would be borne by similarly situated companies in the industry.

In addition, the U.S. Oil Pollution Act ("OPA") requires owners and operators of facilities that could be the source of an oil spill into "waters of the United States," a term defined to include rivers, creeks, wetlands and coastal waters, to adopt and implement plans and procedures to prevent any spill of oil into any waters of the United States. OPA also requires affected facility owners and operators to demonstrate that they have at least $35 million in financial resources to pay for the costs of cleaning up an oil spill and compensating any parties damaged by an oil spill. Substantial civil and criminal fines and penalties can be imposed for violations of OPA and other environmental statutes.

In Canada, the oil and gas industry is currently subject to environmental regulation pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and gas industry operations. In addition, legislation requires that well and facility sites be constructed, abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in substantial cash expenses, including possible fines and penalties.

In Alberta, environmental compliance has been governed by the Alberta Environmental Protection and Enhancement Act ("AEPEA") since September 1, 1993. AEPEA imposes environmental responsibilities on oil and gas operators in Alberta and also imposes penalties for violations.

Employees

As of March 1, 2004, we had 290 full time employees and 11 part time employees. There are no collective bargaining agreements in effect.

Executive Officers

The following information is provided with respect to our officers.

Name	Age	Position(s) Held With Quicksilver
Thomas F. Darden	50	Chairman of the Board
Glenn Darden	48	President, Chief Executive Officer and Director
Bill Lamkin	58	Executive Vice President and Chief Financial Officer
Jeff Cook	47	Senior Vice President—Operations
Mark D. Whitley	52	Vice-President—Operations
Robert N. Wagner	40	Vice-President—Reserves Group
D. Wayne Blair	47	Vice President and Controller
John C. Cirone	53	Vice President, General Counsel and Secretary
Anne Darden Self	46	Vice President—Human Resources and Director
J. Michael Gatens	45	Chairman of the Board and Chief Executive Officer—MGV Energy Inc.
George W. Voneiff	42	President and Chief Operating Officer—MGV Energy Inc.
MarLu Hiller	41	Treasurer

The following biographies describe the business experience of our executive officers and the other officers named above.

THOMAS F. DARDEN has served on our Board of Directors since December 1997. He also served at that time as President of Mercury Exploration Company. During his term as President of Mercury, Mercury developed and acquired interests in over 1,200 producing wells in Michigan, Indiana, Kentucky, Wyoming, Montana, New Mexico and Texas. Mr. Darden graduated from Tulane University with a BA in Economics in 1975. Prior to joining us, Mr. Darden was employed by Mercury or its parent corporation, Mercury Production Company, for 22 years. He became a director and the President of MSR on March 7, 1997. On January 1, 1998, he was named Chairman of the Board and Chief Executive Officer of MSR. He was elected our President when we were formed and then Chairman of the Board and Chief Executive Officer on March 4, 1999, the date of our acquisition of MSR. He served as our Chief Executive Officer until November 1999.

GLENN DARDEN has served on our Board of Directors since December 1997. Prior to that time, he served with Mercury for 18 years, and for the last five of those 18 years was the Executive Vice President of Mercury. Prior to working for Mercury, Mr. Darden worked as a geologist for Mitchell Energy Corporation. He graduated from Tulane University in 1979 with a BA in Earth Sciences. Mr. Darden became a director and Vice President of MSR on March 7, 1997, and was named President and Chief Operating Officer of MSR on

January 1, 1998. He served as our Vice-President until he was elected President and Chief Operating Officer on March 4, 1999. Mr. Darden became our Chief Executive Officer in November 1999.

BILL LAMKIN is a Certified Management Accountant and a Certified Cash Manager with over 20 years of experience in the oil and gas industry. He graduated from Texas Wesleyan University with a BBA in Accounting in 1968. He served as Controller/Chief Financial Officer at Whittaker Corporation and Sargeant Industries, Inc. between 1970 and 1978. He worked as Treasurer, Controller, and Director of Financial Services at Union Pacific Resources from 1978 until he became our Executive Vice President and Chief Financial Officer when he joined us in June 1999.

JEFF COOK became our Senior Vice President-Operations in July 2000. From 1979 to 1981, he held the position of operations supervisor with Western Company of North America. In 1981, he became a District Production Superintendent for Mercury and became Vice President of Operations in 1991 and Executive Vice President in 1998 before joining us. Mr. Cook graduated from Texas Christian University with a BA in Finance in 1979.

MARK D. WHITLEY became our Vice President-Operations in August 2003. He has more than 28 years of oil and gas production and operations experience including 20 years with Mitchell Energy Company LP prior to its 2002 merger with Devon Energy. While at Devon, Mr. Whitley directed the production and operations activity in the exploration of the Fort Worth Basin's Barnett Shale gas play. He graduated with a MS in chemical engineering from the University of Kentucky in 1979 after receiving his undergraduate degree from Worcester Polytechnic Institute.

ROBERT N. WAGNER was named as our Vice President-Reserves Group in December 2002. He had served as our Vice President-Engineering since July 1999. From January 1999 to July 1999, he was our manager of eastern region field operations. From November 1995 to January 1999, Mr. Wagner held the position of district engineer with Mercury. Prior to 1995, he was with Mesa, Inc. for over eight years and served as both drilling engineer and production engineer. Mr. Wagner received a BS in Petroleum Engineering from the Colorado School of Mines in Golden, Colorado in 1986.

D. WAYNE BLAIR is a Certified Public Accountant with over 20 years of experience in the oil and gas industry. He graduated from Texas A&M University in 1979 with a BBA in Accounting. He was employed by Sabine Corporation from 1980 through 1988 where he held the position of Assistant Controller. From 1988 through 1994, he served as Controller for a group of private businesses involved in the oil and gas industry. Prior to joining us in April 2000, he was the Controller for Mercury.

JOHN C. CIRONE was named as our Vice President, General Counsel and Secretary on July 1, 2002. He graduated from St. Louis University School of Law in 1974 and was employed by Union Pacific Resources from 1978 to 2000. During that time, he served in various positions in the Law Department and from 1997 to 2000 he was the Manager of Land and Negotiations. In 2000, he was promoted to the position of Assistant General Counsel of Union Pacific Resources. After leaving Union Pacific Resources in August 2000, Mr. Cirone was engaged in the private practice of law prior to joining us.

ANNE DARDEN SELF has served on our board of directors since September 1999, and she became our Vice President-Human Resources in July 2000. She is also currently President of Mercury, where she has worked since 1992. From 1988 to 1991, she was with Banc PLUS Savings Association in Houston, Texas. She was employed as Marketing Director and then spent three years as Vice President of Human Resources. She worked from 1987 to 1988 as an Account Executive for NW Ayer Advertising Agency. Prior to 1987, she spent several years in real estate management. She attended Sweet Briar College and graduated from the University of Texas in Austin in 1980 with a BA in history.

J. MICHAEL GATENS is Chairman/CEO of MGV Energy Inc., which he co-founded in September 1997 in Calgary, Alberta. MGV became a wholly owned subsidiary of Quicksilver Resources Inc. in December 2000. Mr. Gatens is also Chairman of the Canadian Society for Unconventional Gas, and is MGV's liaison with the Coal Association of Canada and the Canadian Association of Petroleum Producers. Prior to starting MGV in 1997, he worked for S.A. Holditch & Associates, Inc. for 15 years, leaving as Director and Vice President of the Eastern Division in Pittsburgh. Mr. Gatens received BS and MS degrees in Petroleum Engineering from Texas A&M University in 1980 and 1987.

GEORGE W. VONEIFF co-founded MGV Energy Inc. in Calgary, Alberta in September 1997 to pursue unconventional gas opportunities, primarily in Western Canada. MGV became a wholly owned subsidiary of Quicksilver Resources Inc. in December 2000 and Mr. Voneiff continued in his role as President/COO. Prior to founding MGV, he was with the petroleum consulting firm S.A. Holditch & Associates, Inc. from 1991 to 1997 and worked for Enserch Exploration Inc. from 1984 to 1990. Mr. Voneiff received BS and MS degrees in Petroleum Engineering from Texas A&M University in 1983 and 1991.

MARLU HILLER is a Certified Public Accountant with over 15 years of experience in public and oil and gas accounting. She graduated from Baylor University with a BBA in Accounting in 1985, and was with Ernst & Young for three years before joining Union Pacific Resources. At Union Pacific Resources, she served in various capacities, including financial reporting, financial system implementations, and manager of accounting for Union Pacific Fuels, which was Union Pacific Resources' marketing company. Ms. Hiller joined us in August of 1999 as Director of Financial Reporting and Planning and was named Treasurer in May of 2000.

Risk Factors

You should be aware that the occurrence of any of the events described in this Risk Factors section and elsewhere in this annual report or in any other of our filings with the Securities and Exchange Commission ("SEC") could have a material adverse effect on our business, financial position, liquidity and results of operations. In evaluating us, you should consider carefully, among other things, the factors and the specific risks set forth below, and in documents we incorporate by reference. This annual report contains forward-looking statements that involve risks and uncertainties.

Because we have a limited operating history, our future operating results are difficult to forecast, and our failure to sustain profitability in the future could adversely affect the market price of our common stock.

Although our predecessors operated for years in the oil and gas industry prior to our formation, we began operations in 1998, and have a limited operating history in our current form upon which you may base your evaluation of our performance. As a result of our recent formation and our brief operating history, the operating results from the properties contributed by Mercury and others to us when we were formed may not indicate what our future results will be. We cannot assure you that we will maintain the current level of revenues, natural gas and crude oil reserves or production we now attribute to the properties contributed to us when we were formed and those acquired since our formation. Any future growth of our natural gas and crude oil reserves, production and operations could place significant demands on our financial, operational and administrative resources. Our failure to sustain profitability in the future could adversely affect the market price of our common stock.

Natural gas and crude oil prices fluctuate widely, and low prices could have a material adverse impact on our business.

Our revenues, profitability and future growth depend in part on prevailing natural gas and crude oil prices. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under our credit facility is subject to periodic redetermination based in part on changing expectations of future prices. Lower prices may also reduce the amount of natural gas and crude oil that we can economically produce.

While prices for natural gas and crude oil may be favorable at any point in time, they fluctuate widely. For example, the wholesale price of natural gas rose from approximately $2.00 per thousand cubic feet in January of 2002 to over $10.00 in February of 2003. Among the factors that can cause this fluctuation are:

- the level of consumer product demand;
- weather conditions;
- domestic and foreign governmental regulations;
- the price and availability of alternative fuels;
- political conditions in oil and gas producing regions;
- the domestic and foreign supply of oil and gas;
- the price of foreign imports; and
- overall economic conditions.

Our financial statements are prepared in accordance with generally accepted accounting principles. The reported financial results and disclosures were developed using certain significant accounting policies, practices and estimates, which are discussed in the Management's Discussion and Analysis of Financial Condition and Results of Operations section in this annual report. We employ the full cost method of accounting whereby all costs associated with acquiring, exploring for, and developing natural gas and crude oil reserves are capitalized and accumulated in separate country cost centers. These capitalized costs are amortized based on production from the reserves for each country cost center. Each capitalized cost pool cannot exceed the net present value of the underlying natural gas and crude oil reserves. A write down of these capitalized costs could be required if natural gas and/or crude oil prices were to drop precipitously at a reporting period end. Future price declines or increased operating and capitalized costs without incremental increases in natural gas and crude oil reserves could require us to record a write down.

Reserve estimates depend on many assumptions that may turn out to be inaccurate and any material inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves.

The process of estimating natural gas and crude oil reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves disclosed in this annual report.

In order to prepare these estimates, we and independent reserve engineers engaged by us must project production rates and timing of development expenditures. We and the engineers must also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions such as natural gas and crude oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of natural gas and crude oil reserves are inherently imprecise.

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

At December 31, 2003, approximately 19% of our estimated proved reserves were undeveloped. Undeveloped reserves, by their nature, are less certain. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. Our reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our natural gas and crude oil reserves and the costs associated with these reserves in accordance with industry standards, we cannot assure you that the estimated costs are accurate, that development will occur as scheduled or that the actual results will be as estimated.

You should not assume that the present value of future net revenues referred to in this annual report is the current market value of our estimated natural gas and crude oil reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in consumption by natural gas and crude oil purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of natural gas and crude oil properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor. The effective interest rate at various times and the risks associated with us or the oil and gas industry in general will affect the accuracy of the 10% discount factor.

Our key assets are concentrated in a small geographic area.

Approximately 53% of our 2003 production was from the Antrim Shale formation in Michigan. An additional 31% was also located in Michigan. Because of this geographic concentration, any regional events that increase costs, reduce availability of equipment or supplies, reduce demand or limit production, including weather and natural disasters, may impact us more than if our operations were more geographically diversified.

If our production level was significantly reduced or limited below the amounts for which we have entered into contractual deliveries, we would be required to purchase natural gas at market prices to fulfill our obligation under the sales contracts. This could adversely affect our cash flow to the extent any such shortfall related to our sales contracts with floor pricing.

Our Canadian operations present unique risks and uncertainties, different from or in addition to those we face in our domestic operations.

Through MGV, we have entered into joint ventures with other companies to explore for and develop CBM reserves on lands in southern Alberta. MGV shares exploratory and evaluation costs with its joint venture partners. As a result of MGV's exploration activities to date, we estimate our proved CBM reserves to be 131.3 Bcf. We expect MGV to accelerate its scheduled activities, expand into other areas and increase its capital expenditures. Capital expenditures relating to MGV's operations are budgeted to be approximately $89 million in 2004, constituting approximately 57% of our total budgeted capital expenditures.

If our revenues decrease as a result of lower natural gas or crude oil prices or otherwise, we may have limited ability to maintain this level of capital expenditures. In the event additional capital resources are unavailable to us, we may curtail our acquisition, development drilling and other activities outside of Canada in order to keep pace with Canadian drilling activities. While initial results indicate that net recoverable reserves on CBM lands could be substantial, we can offer you no assurance that development will occur as scheduled or that actual results will be in accordance with estimates.

Other risks of our operations in Canada include, among other things, increases in taxes and governmental royalties, changes in laws and policies governing operations of foreign-based companies, currency restrictions and exchange rate fluctuations. Laws and policies of the United States affecting foreign trade and taxation may also adversely affect our Canadian operations.

We may have difficulty financing our planned growth.

We have experienced and expect to continue to experience substantial capital expenditure and working capital needs, particularly as a result of our property acquisition and drilling activities. In the future, we will most likely require additional financing in addition to cash generated from our operations to fund our planned growth. If revenues decrease as a result of lower natural gas or crude oil prices or otherwise, we may have limited ability to expend the capital necessary to replace our reserves or to maintain production at current levels, resulting in a decrease in production over time. If our cash flow from operations is not sufficient to satisfy our capital expenditure requirements, we cannot be certain that additional financing will be available to us on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail our acquisition, development drilling and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

We are vulnerable to operational hazards, transportation dependencies, regulatory risks and other uninsured risks associated with our activities.

The oil and gas business involves operating hazards such as well blowouts, explosions, uncontrollable flows of crude oil, natural gas or well fluids, fires, formations with abnormal pressures, pipeline ruptures or spills, pollution, releases of toxic gas and other environmental hazards and risks, any of which could cause us to experience substantial losses. Also, the availability of a ready market for our natural gas and crude oil production depends on the proximity of reserves to, and the capacity of, natural gas and crude oil gathering systems, pipelines and trucking or terminal facilities.

United States and Canadian federal, state and provincial regulation of oil and gas production and transportation, tax and energy policies, changes in supply and demand and general economic conditions all could adversely affect our ability to produce and market our natural gas and crude oil. In addition, we may be liable for environmental damage caused by previous owners of properties purchased or leased by us.

As a result of operating hazards, regulatory risks and other uninsured risks, we could incur substantial liabilities to third parties or governmental entities, the payment of which could reduce or eliminate funds available for exploration, development or acquisitions. According to customary industry practices, we maintain insurance against some, but not all, of such risks and losses. The occurrence of an event that is not covered, or not fully covered, by insurance could have a material adverse effect on our business, financial condition and results of operations. In addition, pollution and environmental risks generally are not fully insurable.

We may be unable to make additional acquisitions of producing properties or successfully integrate them into our operations.

Our growth in recent years has been due in significant part to acquisitions of producing properties. We expect to continue to evaluate and, where appropriate, pursue acquisition opportunities on terms our management considers to be favorable to us. We cannot assure you that we will be able to identify suitable acquisitions in the future, or that we will be able to finance these acquisitions on favorable terms or at all. In addition, we compete against other companies for acquisitions, and we cannot assure you that we will be successful in the acquisition of any material property interests. Further, we cannot assure you that any future acquisitions that we make will be integrated successfully into our operations or will achieve desired profitability objectives.

The successful acquisition of producing properties requires an assessment of recoverable reserves, exploration potential, future natural gas and crude oil prices, operating costs, potential environmental and other liabilities and other factors beyond our control. These assessments are necessarily inexact and their accuracy inherently uncertain, and such a review may not reveal all existing or potential problems, nor will it necessarily permit us to become sufficiently familiar with the properties to fully assess their merits and deficiencies. Inspections may not always be performed on every well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken.

In addition, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may be substantially different in operating and geological characteristics or geographic location than existing properties. While our current operations are located primarily in Michigan, Indiana, Montana, Wyoming and Alberta, Canada, we cannot assure you that we will not pursue acquisitions of properties in other locations.

The failure to replace our reserves could adversely affect our production and cash flows.

Our future success depends upon our ability to find, develop or acquire additional natural gas and crude oil reserves that are economically recoverable. Our proved reserves, which are primarily in the mature Michigan basin, will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. In order to increase reserves and production, we must continue our development drilling and recompletion programs or undertake other replacement activities. Our current strategy is to maintain our focus on low-cost operations while increasing our reserve base, production and cash flow through development and exploration of our existing properties and acquisitions of producing properties where we can utilize our experience as a low-cost operator. We cannot assure you, however, that our planned development projects and acquisition activities will result in significant additional reserves or that we will have continuing success drilling productive wells at low finding and development costs. Furthermore, while our revenues may increase if prevailing natural gas and crude oil prices increase significantly, our finding costs for additional reserves also could increase.

We cannot control the activities on properties we do not operate.

Other companies operate properties that include approximately 27% of our proved reserves. As a result, we have a limited ability to exercise influence over operations for these properties or their associated costs. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities. As a result, the success and timing of our drilling and development activities on properties operated by others depend upon a number of factors that are outside of our control, including:

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

We cannot control the operations of gas processing and transportation facilities we do not own or operate.

Other companies own processing plants and pipelines that deliver approximately 58% of our natural gas production to market in Michigan. As a result, we have no influence over the operation of these facilities and must depend upon the owners of these facilities to minimize any loss of processing and transportation capacity. This risk was highlighted in 2003 by the shutdown of CMS Energy Inc. and Michigan Consolidated Gas Co. processing plants in Michigan that resulted in an approximate 725 Mmcf decrease in our production for the year.

The loss of key personnel could adversely affect our ability to operate.

Our operations are dependent on a relatively small group of key management and technical personnel. We cannot assure you that these individuals will remain with us for the immediate or foreseeable future. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on us.

Competition in our industry is intense, and we are smaller and have a more limited operating history than most of our competitors.

We compete with major and independent oil and gas companies for property acquisitions. We also compete for the equipment and labor required to operate and develop these properties. Many of our competitors have substantially greater financial and other resources than we do. In addition, larger competitors may be able to absorb the burden of any changes in federal, state, provincial and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be able to pay more for exploratory prospects and productive oil and gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for oil and gas prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to complete transactions in this highly competitive environment. Furthermore, the oil and gas industry competes with other industries in supplying the energy and fuel needs of industrial, commercial, and other consumers.

Leverage materially affects our operations.

As of December 31, 2003, our long-term debt was $249.4 million, including $178.0 million outstanding under our bank credit facility, $70.0 million outstanding under our second lien notes and $1.4 million of other debt. Our borrowing base was $250 million and we had $70.5 million of available borrowing capacity under our bank credit facility. The borrowing base limitation on our credit facility is periodically redetermined. Scheduled redeterminations occur on May 1 and November 1 of each year. Our borrowing base is impacted by, among other factors, the fair value of our oil and gas reserves. Changes in the fair value of our oil and gas reserves are affected by prices for natural gas and crude oil, operating expenses and the results of our drilling activity. A significant decline in the fair value of our reserves could reduce our borrowing base. A borrowing base reduction could limit our ability to carry out our capital expenditure programs and possibly require the repayment of a portion of our current bank borrowings.

Our level of debt affects our operations in several important ways, including the following:

- a large portion of our cash flow from operations is used to pay interest on borrowings;
- the agreements governing our debt contain covenants that limit our ability to borrow additional funds or to dispose of assets;
- the covenants contained in the agreements governing our debt may affect our flexibility in planning for, and reacting to, changes in business conditions;
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes;
- our leveraged financial position may make us more vulnerable to economic downturns and may limit our ability to withstand competitive pressures, despite our entry into long-term natural gas contracts with price floors and hedging arrangements to reduce our exposure;
- any debt that we incur under our bank credit facility will be at variable rates, making us vulnerable to increases in interest rates, to the extent those rates are not hedged; and
- a high level of debt will affect our flexibility in planning for or reacting to changes in market conditions.

In addition, we may significantly alter our capitalization in order to make future acquisitions or develop our properties. These changes in capitalization may significantly increase our level of debt. A higher level of debt increases the risk that we may default on our debt obligations. Our ability to meet debt obligations and to reduce our level of debt depends on our future performance. General economic conditions and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control.

If we are unable to repay our debt as required out of cash on hand, we could attempt to refinance the debt or repay the debt with the proceeds of an equity offering. We cannot assure you that we will be able to generate sufficient cash flow to pay the principal or interest on our debt or that future borrowing or equity financing will be available to pay or refinance the debt. The terms of our debt may also prohibit us from taking these actions. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions and our market value and operations performance at the time of the offering or other financing. We cannot assure you that any offering or refinancing can be successfully completed. In the event additional capital resources are unavailable, we may curtail our acquisition, development drilling and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

Several companies have entered into purchase contracts with us for a significant portion of our production and if they default on these contracts, we could be materially and adversely affected.

Our long-term natural gas contracts, which extend through March 2009, accounted in 2003 for the sale of approximately 36% of our natural gas production and for a significant portion of our total revenues. We cannot assure you that the other parties to these contracts will continue to perform under the contracts. If the other parties were to default after taking delivery of our natural gas, it could have a material adverse effect on our cash flows for the period in which the default occurred. A default by the other parties prior to taking delivery of our natural gas could also have a material adverse effect on our cash flows for the period in which the default occurred depending on the prevailing market prices of natural gas at the time compared to the contractual prices.

Hedging our production may result in losses.

To reduce our exposure to fluctuations in the prices of natural gas and crude oil, we have entered into long-term natural gas and crude oil hedging arrangements. These hedging arrangements expose us to risk of financial loss in some circumstances, including the following:

- our production is materially less than expected; or
- the other parties to the hedging contracts fail to perform their contractual obligations.

In addition, these hedging arrangements may limit the benefit we would receive from increases in the prices for natural gas and crude oil in the following instances:

- there is a change in the expected difference between the underlying price in the hedging agreement and actual prices received; or
- a sudden unexpected event materially impacts natural gas or crude oil prices.

The result of natural gas and crude oil market prices exceeding our swap prices requires us to make payment for the settlement of our hedge derivatives on the fifth day of the production month for natural gas hedges and the fifth day after the production month for crude oil hedges. We do not receive market price cash payments from our customers until 25 to 60 days after the production month's end. This could have a material adverse effect on our cash flows for the period between hedge settlement and payment for revenues earned.

If we choose not to engage in hedging arrangements in the future, we may be more adversely affected by changes in natural gas and crude oil prices than our competitors who engage in hedging arrangements.

Our activities are regulated by complex laws and regulations, including environmental regulations that can adversely affect the cost, manner or feasibility of doing business.

Oil and gas operations are subject to various United States and Canadian federal, state, provincial and local government laws and regulations that may be changed from time to time in response to economic or political conditions. Matters that are typically regulated include:

- discharge permits for drilling operations;

- drilling bonds;
- reports concerning operations;
- spacing of wells;
- unitization and pooling of properties;
- environmental protection; and
- taxation.

From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and gas wells below actual production capacity to conserve supplies of natural gas and crude oil. We also are subject to changing and extensive tax laws, the effects of which cannot be predicted.

The development, production, handling, storage, transportation and disposal of natural gas and crude oil, by-products and other substances and materials produced or used in connection with oil and gas operations are also subject to laws and regulations primarily relating to protection of human health and the environment. The discharge of natural gas, crude oil or pollutants into the air, soil or water may give rise to significant liabilities on our part to the government and third parties and may result in the assessment of civil or criminal penalties or require us to incur substantial costs of remediation.

Legal and tax requirements frequently are changed and subject to interpretation, and we are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. We cannot assure you that existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations, will not materially adversely affect our business, results of operations and financial condition.

A small number of existing stockholders control our company, which could limit your ability to influence the outcome of stockholder votes.

Members of the Darden family, together with Mercury Exploration Company and Quicksilver Energy, L.P., companies primarily owned by the members of the Darden family, beneficially own on the date of this annual report approximately 38% of our common stock. As a result, these entities and individuals will generally be able to control the outcome of stockholder votes, including votes concerning the election of directors, the adoption or amendment of provisions in our charter or bylaws and the approval of mergers and other significant corporate transactions.

A large number of our outstanding shares and shares to be issued upon exercise of our outstanding options may be sold into the market in the future, which could cause the market price of our common stock to drop significantly, even if our business is doing well.

Our shares that are eligible for future sale may have an adverse effect on the price of our stock. There were 24,733,411 shares of our common stock outstanding at December 31, 2003, including 170,421 shares issuable upon exchange of exchangeable shares issued by MGV Energy Inc., one of our subsidiaries. Approximately 14,953,277 of these shares are freely tradable without substantial restriction or the requirement of future registration under the Securities Act of 1933. In addition, as of December 31, 2003 we had the following options outstanding to purchase shares of our common stock:

- Options to purchase 235,933 shares at $3.6875 per share;
- Options to purchase 208,333 shares at $7.125 per share;
- Options to purchase 33,352 shares at $9.80 per share;
- Options to purchase 49,723 shares at $16.04 per share;

- Options to purchase 9,800 shares at $16.50 per share;
- Options to purchase 42,385 shares at $17.02 per share;
- Options to purchase 29,620 shares at $22.08 per share; and
- Options to purchase 20,210 shares at $24.10 per share.

Sales of substantial amounts of common stock, or a perception that such sales could occur, and the existence of options to purchase shares of common stock at prices that may be below the then current market price of the common stock, could adversely affect the market price of our common stock and could impair our ability to raise capital through the sale of our equity securities.

Our restated certificate of incorporation, our bylaws and our stockholder rights plan contain provisions that could discourage an acquisition or change of control without our board of directors' approval.

Our restated certificate of incorporation and our bylaws contain provisions that could discourage an acquisition or change of control without our board of directors' approval, such as:

- our board of directors is authorized to issue preferred stock without stockholder approval;
- our board of directors is classified; and
- advance notice is required for director nominations by stockholders and actions to be taken at annual meetings at the request of stockholders.

In addition, we have adopted a stockholder rights plan. The provisions, described above and the stockholder rights plan could impede a merger, consolidation, takeover or other business combination involving us or discourage a potential acquirer from making a tender offer or otherwise attempting to take control of us, even if that change of control might be beneficial to stockholders, thus increasing the likelihood that incumbent directors will retain their positions. In certain circumstances, the fact that corporate devices are in place that will inhibit or discourage takeover attempts could reduce the market value of our common stock.

Internet Website

We file annual, quarterly and special reports, proxy statements and other information with the SEC. Our SEC filings are available to the public over the Internet at the SEC's web site at http://www.sec.gov. You may also read and copy any document we file at the SEC's public reference room at 450 Fifth Street, N.W., Washington, D.C. 20549. You may obtain information on the operation of the SEC's public reference room in Washington, D.C. by calling the SEC at 1-800-SEC-0330. In addition, we make available free of charge through our Internet website at http://www.qrinc.com, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

Additionally, charters for the committees of our Board of Directors and our Corporate Governance Guidelines and Code of Business Conduct and Ethics can be found on our Internet website at http://www.qrinc.com under the heading "Corporate Governance." Stockholders may request copies of these documents by writing to the Investor Relations Department at 777 West Rosedale Street, Suite 300, Fort Worth, Texas 76104.

ITEM 2. Properties

We own significant natural gas and crude oil production interests in the following geographic areas:

Michigan

Producing Formation	Proved Reserves (Bcfe)	% Gas	% Proved Developed	2003 Production (MMcfed)
Antrim Shale	535.7	100%	90%	57.9
Non-Antrim	84.0	65%	84%	34.3
All Formations	619.7	95%	89%	92.2

Michigan has favorable natural gas supply/demand characteristics as the state has been importing an increasing percentage of its natural gas and currently imports approximately 75% of its demand. This supply/demand situation generally allows Michigan producers to sell their natural gas at a slight premium to typical industry benchmark prices.

The Antrim Shale underlies a large percentage of our Michigan acreage and is fairly homogeneous in terms of reservoir quality; wells tend to produce relatively predictable amounts of natural gas. While subsurface fracturing can increase reserves and production attributable to any particular well, the over 7,800 wells drilled in the trend and the approximately 841 wells we, including Mercury prior to our formation, have drilled suggest typical per well reserves of 400 MMcf to 800 MMcf and a total productive life of more than 20 years. As new wells produce and the de-watering process takes place, they tend to reach a production level of 125 Mcf to 200 Mcf per day in six to 12 months, remaining at these levels for one to two years, then declining at 8% to 10% per year thereafter. The total cost to drill and complete an Antrim well is approximately $175,000, including all acreage, production facilities and flow lines, and the wells tend to produce the best economic results when drilled in large numbers in a fairly concentrated area. This well concentration provides for a more rapid de-watering of a specific area, which decreases the time to natural gas production and increases the amount of natural gas production. It also enables us to maximize the use of existing production infrastructure, which decreases per unit operating costs. Since reserve quantities and production levels over a large number of wells are fairly predictable, maximizing per well recoveries and minimizing per unit production costs through a sizeable well-engineered drilling program are the keys to profitable Antrim development.

At December 31, 2003, we owned working interests in 2,927 Antrim wells and operated 50% of those wells. Since 1998, we have drilled 418 Antrim wells and successfully completed 412 for a success rate of 99%. We have 103 net identified Antrim drilling locations currently classified as proved undeveloped locations. In 2003, we drilled and successfully completed 54.7 (net) Antrim wells. For 2004, we have budgeted for the drilling of 51 (net) Antrim wells, including several horizontal wells.

Our Prairie du Chien ("PdC") wells produce from several Ordovician age reservoirs with the majority being in the 1,000 feet to 1,200 feet thick PdC Group that has three major sands: the Lower PdC, Middle PdC and Upper PdC. Many of these wells also can produce from the St. Peter sandstone and the Glenwood formations, both of which lie directly above the PdC. Some of the wells are producing from two or more of these zones. Depending upon the area and the particular zone, the PdC will produce dry gas, gas and condensate or oil with associated gas. The average depths of these wells range from 7,000 feet to 12,000 feet.

Our PdC production is well established, and four development wells have been drilled in recent years to increase production from existing fields. There are numerous proved non-producing zones in existing well bores that provide recompletion opportunities, allowing us to maintain or, in some cases, increase production from our PdC wells as currently producing reservoirs deplete. We participated in one non-operated PdC well in 2003 and are currently drilling the second of two PdC wells in the Beaver Creek field. Production from the three wells is expected to commence in the first half of 2004.

Our Richfield/Detroit River wells are located in Kalkaska and Crawford counties in the Garfield and Beaver Creek fields. The Garfield Richfield has seven wells producing under primary solution gas drive. Additional potential exists in the Garfield Richfield either by secondary waterflood and/or improved oil recovery with CO2 injection. The potential upside is under evaluation and has not been included in our booked reserves. The Beaver Creek Richfield is currently being waterflooded, with 96 producing wells and 58 water injection wells. The Richfield zone consists of seven dolomite reservoirs spread over a 200-foot interval.

The Detroit River Zone III ("DRZ3") at Beaver Creek was the focus of one of our development programs in 2002. Lying approximately 200 feet above the Richfield, the DRZ3 is a six-foot dolomite zone that covers approximately 10,000 acres on the Beaver Creek structure. We began a Detroit River development program in the third quarter of 2002. As of December 31, 2003, 29 wells were producing. A processing plant and related facilities were completed in 2003 after production commenced in late 2002. Proved reserves associated with the DRZ3 development were reduced 1.4 MMBbl as a result of early disappointing production results. While there is the opportunity for improving production and proved reserve quantities, we have determined that our resources are better allocated to continued exploration and development of our many unconventional gas projects.

Our Niagaran wells produce from numerous Silurian-age Niagaran (dolomite/limestone) pinnacle reefs located in nine counties in Northern Michigan. The depth of these wells range from 3,400 feet to 7,800 feet with reservoir thickness from 300 feet to 600 feet. Depending upon the location of the specific reef in the pinnacle reef belt of the northern shelf area, the Niagaran reefs will produce dry gas, gas and condensate or oil with associated gas. As of December 31, 2003, we had 66 gross (30.2 net) Niagaran wells.

Indiana

We acquired a 100% working interest in 33 New Albany Shale producing wells in 2000. Included with the acquisition of these producing wells, we also acquired the eight-mile 12-inch GTG gas pipeline that runs from southern Indiana to northern Kentucky. We have drilled an additional 119 wells since 2000 and acquired 35 non-producing wells. The New Albany Shale is similar to the Michigan Antrim, as it has to be dewatered in order to produce desorbed methane gas. Typical reserves per well are estimated to be approximately 320 MMcf.

Including the 90 wells drilled and 35 wells acquired in 2003, we have 190 total wells in this New Albany Shale area. Average daily production in 2003 from all of our New Albany Shale wells was 2.4 MMcfd. In September 2003, we commenced transportation of New Albany production through a pipeline extension that connects to the Texas Gas Pipeline in northern Kentucky. At December 31, 2003, daily production from our New Albany Shale wells was 5.7 MMcfd. In 2004, we intend to reestablish production from approximately 24 of the 35 non-producing wells acquired in 2003 and anticipate drilling approximately 58 wells in the New Albany Shale.

Canada

In 2000, we began to focus on the potential of Canadian CBM through MGV. In late 2000, we entered into a joint venture with EnCana to explore for and develop CBM reserves initially in the West Palliser block in the province of Alberta. By January 2003, the joint venture had drilled 175 exploratory, pilot and development wells. In January 2003, we entered into an asset rationalization agreement with EnCana to divide the assets and rights subject to the joint venture and allow us to pursue independent operations. In 2003 we drilled 184 successful wells, most as operator, including significant developments in the Gayford and Beiseker areas. By December 31, 2003, we had proved reserves of 131.3 Bcf from our CBM projects and had ongoing field operations in all our joint ventures. Commercial CBM wells had been connected to sales points in many locations up to 100 miles north of the West Palliser block. These wells will continue to exhibit production rates generally between 50 and 250 Mcfd with negligible water production.

Our Gayford and Beiseker development areas include 132 net producing wells drilled or acquired by year-end 2003. Commercial production began in the Gayford area from 23 wells in January 2003 with additional drilling bringing the Gayford well total to 71 net wells by year-end. Beiseker development production began in August 2003 with 61 net wells producing by year-end. Numerous other CBM wells were drilled outside of the Gayford and Beiseker areas as exploration, pilot or pre-development wells, with some of those tied into sales lines for long-term tests. Our 2004 plans for Canadian CBM projects include the drilling of approximately 280 net wells, with the majority of those being CBM development wells.

MGV also owns interests in other natural gas properties located in southern Alberta. At the end of 2003, MGV held interests in 763 gross (333 net wells). All of these properties are located in southern Alberta.

Our Canadian proved reserves at December 31, 2003 were estimated to be 146.6 Bcf, including 131.3 Bcf of reserves from our CBM projects. Our average daily production in Canada for 2003 was 8.0 MMcfd. By year-end 2003 we were producing approximately 18 Mmcfd in Canada with 16 Mmcfd of that production from our CBM projects.

Rocky Mountain Region

Our Rocky Mountain properties are located in Montana and Wyoming, and production, which is primarily crude oil, is from well-established producing formations at depths ranging from 1,000 feet to 17,000 feet. These properties typically have multiple producing zones, some of which include the Phosphoria at 750 feet to 1,000 feet, the Tensleep at 1,000 feet to 3,000 feet and the Muddy/Mowry at 8,400 feet to 9,000 feet. Our Rocky Mountain properties possess significant development drilling, secondary recovery and other exploitation opportunities. As of December 31, 2003, our Rocky Mountain proved reserves were 10 MMbbls of crude oil and 4.0 Bcfe of natural gas and NGLs for total equivalent reserves of 63.8 Bcfe. In 2003, our daily production averaged 7.5 MMcfed.

Oil and Gas Reserves

The following reserve quantity and future net cash flow information concerns our proved reserves that are located in the United States and Canada. Independent petroleum engineers with Schlumberger Data and Consulting Services and Netherland, Sewell & Associates, Inc. prepared our reserve estimates. Proved oil and gas reserves, as defined by SEC Regulation S-X Rule 4-10(a) (2i), 2(ii), 2(iii), (3) and (4), are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. Prices do not include the effect of derivative instruments we have entered into. Future production and development costs include production and property taxes.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for re-completion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.

The reserve data set forth in this document represents only estimates and is subject to inherent uncertainties. The determination of oil and gas reserves is based on estimates that are highly complex and interpretive. Reserve engineering is a subjective process that is dependent on the quality of available data and on engineering and geological interpretation and judgment. Although we believe the reserve estimates contained in this document are reasonable, reserve estimates are imprecise and are expected to change, as additional information becomes available.

The following table summarizes our proved reserves and the standardized measure of discounted future net cash flows attributable to them at December 31, 2003, 2002 and 2001.

	Years Ended December 31, Total Proved Reserves			Years Ended December 31, Proved Developed Reserves		
	2003	2002	2001	2003	2002	2001
Natural gas (MMcf)						
United States	643,520	637,983	535,009	569,979	550,889	456,074
Canada	146,632	53,602	16,513	83,698	22,750	8,890
Total	790,152	691,585	551,522	653,677	573,639	464,964
Crude oil (MBbl)						
United States	13,173	16,002	13,344	8,734	10,722	8,543
Canada	—	—	—	—	—	—
Total	13,173	16,002	13,344	8,734	10,722	8,543
NGL (MBbl)						
United States	1,918	2,216	1,538	1,405	1,524	1,023
Canada	—	—	—	—	—	—
Total	1,918	2,216	1,538	1,405	1,524	1,023
Total (MMcfe)	880,696	800,893	640,814	714,511	647,115	522,360

	Year ended December 31,		
	2003	2002	2001
Representative crude oil and natural gas prices: (1)			
Natural gas—NYMEX Henry Hub	$ 5.97	$ 4.74	$ 2.57
Crude oil—NYMEX	32.55	31.20	19.84
Present values (in thousands): (2)			
Standardized measure of discounted future net cash flows, before income tax	$1,200,650	$867,748	$358,950
Standardized measure of discounted future net cash flows, after income tax	$ 848,741	$614,851	$268,942

(1) The natural gas and crude oil prices as of each respective year-end were based, respectively, on NYMEX Henry Hub prices per MMbtu and NYMEX prices per Bbl, with these representative prices adjusted by field to arrive at the appropriate corporate net price.

(2) Determined based on year-end unescalated prices and costs in accordance with the guidelines of the SEC, discounted at 10% per annum.

Volumes, Sales Prices and Oil and Gas Production Expense

The following table sets forth certain information regarding production, average unit prices and costs for the periods indicated:

	Years Ended December 31,		
	2003	2002	2001
Production:			
Natural gas (MMcf)			
United States	31,612	31,910	31,815
Canada	2,924	935	874
Total natural gas	34,536	32,845	32,689
Crude oil (MBbl)			
United States	807	905	1,059
Canada	1	—	—
Total crude oil	808	905	1,059
NGL (MBbl)			
United States	133	156	192
Canada	2	—	3
Total NGL	135	156	195
Total production (Mmcfe)	40,192	39,209	40,212
Average Prices (including impact of hedges):			
Natural gas—per Mcf			
United States	$ 3.32	$ 2.77	$ 3.05
Canada	3.98	2.13	2.47
Consolidated	3.38	2.75	3.03
Crude oil—per Bbl			
United States	$ 24.23	$ 21.74	$ 21.03
Canada	24.46	—	—
Consolidated	24.23	21.74	21.03
NGL—per Bbl			
United States	$ 21.45	$ 14.97	$ 19.97
Canada	26.01	—	21.76
Consolidated	21.50	14.97	19.97
Average Prices (excluding impact of hedges):			
Natural gas—per Mcf			
United States	$ 4.50	$ 2.99	$ 3.68
Canada	4.15	2.22	3.05
Consolidated	4.47	2.97	3.67
Crude oil—per Bbl			
United States	$ 26.69	$ 21.86	$ 21.03
Canada	24.46	—	—
Consolidated	26.69	21.86	21.03
NGL—per Bbl			
United States	$ 21.45	$ 14.97	$ 19.97
Canada	26.01	—	21.76
Consolidated	21.50	14.97	19.97
Production cost (per Mcfe) (1)			
United States	$ 1.29	$ 1.06	$ 1.28
Canada	1.35	1.84	1.95
Consolidated	1.30	1.08	1.31

(1) Includes production taxes.

Drilling Activity

During the periods indicated, the Company drilled or participated in the drilling of the following exploratory and development wells:

	Years Ended December 31,					
	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Development:						
United States						
Productive	102.0	74.3	106.0	81.2	148.0	109.0
Non-productive	—	—	1.0	1.0	—	—
Canada						
Productive	32.0	32.0	17.0	17.0	51.0	13.6
Non-productive	—	—	—	—	—	—
Total	134.0	106.3	124.0	99.2	199.0	122.6
Exploratory:						
United States						
Productive	76.0	73.3	24.0	22.9	4.0	3.0
Non-productive	1.0	1.0	3.0	3.0	5.0	4.5
Canada						
Productive	152.0	116.5	44.0	26.2	85.0	33.1
Non-productive	1.0	0.4	—	—	—	—
Total	230.0	191.2	71.0	52.1	94.0	40.6
Total:						
Productive	362.0	296.1	191.0	147.3	288.0	158.7
Non-productive	2.0	1.4	4.0	4.0	5.0	4.5
Total	364.0	297.5	195.0	151.3	293.0	163.2

Acquisition, Exploration and Development Capital Expenditures

	United States	Canada	Consolidated
		(in thousands)	
2003			
Proved acreage	$ 3,215	$ 3,388	$ 6,603
Unproved acreage	24,063	6,739	30,802
Development costs	47,480	43,001	90,481
Exploration costs	9,411	17,066	26,477
Total	$84,169	$70,194	$154,363
2002			
Proved acreage	$32,199	$ —	$ 32,199
Unproved acreage	550	5,422	5,972
Development costs	34,178	938	35,116
Exploration costs	5,925	8,659	14,584
Total	$72,852	$15,019	$ 87,871
2001			
Proved acreage	$ 2,811	$ 343	$ 3,154
Unproved acreage	2,595	197	2,792
Development costs	47,776	2,229	50,005
Exploration costs	2,081	8,022	10,103
Total	$55,263	$10,791	$ 66,054

Productive Oil and Gas Wells

The following table summarizes productive oil and gas wells attributable to our direct interests as of December 31, 2003:

	As of December 31, 2003 Productive Wells			
	Natural Gas		Crude Oil	
	Gross	Net	Gross	Net
United States	4,695	1,547.7	448	414.8
Canada	622	234.6	3	0.1
Total	5,317	1,782.3	451	414.9

Oil and Gas Acreage

Our principal natural gas and crude oil properties consist of non-producing and producing natural gas and crude oil leases, including reserves of natural gas and crude oil in place. The following table indicates our interest in developed and undeveloped acreage held directly by us. Developed acres are defined as acreage spaced or allocated to wells that are producing or capable of producing. Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or gas, regardless of whether or not such acreage contains proved reserves. Gross acres are the total number of acres in which we have a working interest. Net acres are the sum of our fractional interests owned in the gross acres.

	As of December 31, 2003			
	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
United States	685,891	362,476	615,733	497,853
Canada	79,336	40,442	519,247	384,665
Total	765,227	402,918	1,134,980	882,518

ITEM 3. Legal Proceedings

In August 2001, a group of royalty owners, Athel E. Williams et al., brought suit against us and three of our subsidiaries in the Circuit Court of Otsego County, Michigan. The suit alleges that Terra Energy Ltd, one of our subsidiaries, underpaid royalties or overriding royalties to the 13 named plaintiffs and to a class of plaintiffs who have yet to be determined. The pleadings of the plaintiffs seek damages in an unspecified amount and injunctive relief against future underpayments. The court heard arguments on class certification on November 8, 2002, and on December 6, 2002 the court issued a memorandum opinion granting class certification in part and denying it in part. The court stated that those portions of the royalty owners' complaint against us alleging that we deducted excessive postproduction costs from royalty payments should not be certified as class action. The court certified the remainder of the complaint for class action status. On December 20, 2002, we filed a motion for clarification and reconsideration of the court's order. That motion was denied on March 9, 2003. Based on information currently available to us, we believe that the final resolution of this matter will not have a material effect on our financial condition, results of operations, or cash flows.

ITEM 4. Submission of Matters to a Vote of Security Holders

There were no matters submitted to a stockholder vote during the fourth quarter of 2003.

PART II.

ITEM 5. Market For Registrant's Common Equity, Related Stockholder Matters and Issuer Purchase of Equity Securities

Market Information

Our common stock is traded on the New York Stock Exchange under the symbol "KWK".

The following table sets forth the quarterly high and low sales prices of our common stock for the periods indicated below.

	HIGH	LOW
2003		
Fourth Quarter	$33.65	$24.40
Third Quarter	26.15	22.94
Second Quarter	26.11	22.46
First Quarter	24.43	19.54
2002		
Fourth Quarter	$24.40	$16.79
Third Quarter	25.95	16.89
Second Quarter	26.35	21.30
First Quarter	23.50	16.80

As of March 1, 2004, there were approximately 519 common stockholders of record.

We have not paid dividends on our common stock and intend to retain our cash flow from operations for the future operation and development of our business. In addition, our primary credit facility prohibits payments of dividends on our common stock.

ITEM 6. Selected Financial Data

The following tables set forth, as of the dates and for the periods indicated, our selected financial information. Our financial information is derived from our audited consolidated financial statements for such periods. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and notes thereto contained in this document. The following information is not necessarily indicative of our future results.

Selected Financial Data
(Unaudited)
(in thousands, except for per share data)

	Years Ended December 31,				
	2003	2002	2001	2000	1999
Consolidated Statements of Income Data:					
Total revenues	$ 140,949	$121,979	$141,963	$ 118,392	$ 49,913
Income before income taxes	28,502	21,333	30,110	27,731	3,023
Income before cumulative effect of change in accounting principle	18,505	13,835	19,310	17,618	3,162
Net income	16,208	13,835	19,310	17,618	3,162
Earnings—per share before accounting change					
Basic	$ 0.83	$ 0.70	$ 1.03	$ 0.96	$ 0.24
Diluted	0.81	0.68	1.00	0.95	0.24
Earnings—per share					
Basic	$ 0.72	$ 0.70	$ 1.03	$ 0.96	$ 0.24
Diluted	0.71	0.68	1.00	0.95	0.24

	Years Ended December 31,				
	2003	2002	2001	2000	1999
Consolidated Statements of Cash Flows Data:					
Net cash provided by (used in):					
Operating activities	$ 63,053	$ 43,999	$ 57,921	$ 47,691	$ 10,220
Investing activities	(147,422)	(83,659)	(67,227)	(195,518)	(42,288)
Financing activities	79,369	40,050	5,199	158,103	34,330
Capital expenditures	$ 148,488	$ 88,965	$ 67,566	$ 194,507	$ 43,452
Consolidated Balance Sheets Data:					
Working capital (deficit) (1)	$ (30,803)	$ (23,678)	$ (19,141)	$ 935	$ 7,168
Properties—net	604,576	470,078	412,455	374,099	170,800
Total assets	666,934	529,538	471,884	440,111	194,302
Long-term debt	249,097	248,493	248,425	239,986	94,952
Stockholders' equity	241,816	128,905	94,387	86,758	69,551

(1) Working capital includes the current portion of assets and liabilities, which reflect estimated fair value of derivative obligations.

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

We are an independent oil and gas company engaged in the exploration, acquisition, development, production and sale of natural gas, crude oil and natural gas liquids primarily from unconventional reservoirs such as fractured shales, coal beds and tight sands. At December 31, 2003, approximately 90% of our proved reserves were natural gas. Approximately 70% of those reserves are located in Michigan.

Our Michigan activities have allowed us to develop a technical and operational expertise in the acquisition, development and production of unconventional natural gas reserves. Consistent with one of our business strategies, our Canadian coal bed methane and Indiana New Albany Shale projects represent an extension of that expertise.

For 2004, we plan to focus on the exploration and development of CBM reserves in Alberta, Canada, the New Albany shale in Indiana/Kentucky and the Barnett shale in Texas. We expect budgeted capital expenditures for 2004 to be approximately $157 million, of which, about $89 million is allocated to our Canadian operations with the remainder allocated to our U.S. operations.

We generate net income and cash flows on an ongoing basis by producing natural gas, crude oil and natural gas liquids in quantities and at prices that allow us to not only generate operating income, but also allow us to conduct exploration, development and acquisition activities to efficiently replace the reserves that have been produced.

We use several measurements to determine our performance. Among the key measurements we use are: cash flow from operating activities; operating expenses per unit of production; overhead costs per unit of production; finding costs per unit of reserve addition; and the ratio of total reserve additions to production during a given period of time.

Natural gas prices were favorable throughout 2003 and many industry analysts expect them to remain favorable for the foreseeable future. If prices for natural gas remain favorable, we will be able to fund more of our capital expenditures with cash flow from operations; however, we do not expect our cash flow from operations to be sufficient to satisfy our total budgeted capital expenditures. To fund our total budgeted capital expenditures in 2004 we plan to borrow additional funds under our existing bank credit facility. Consequently, our level of debt will increase. As of December 31, 2003, we had $70.5 million of available borrowing capacity under our bank credit facility. The ratio of our total debt to equity as of December 31, 2003 was approximately one to one.

The possibility of decreasing prices to be received for production is among the several risks that we face. We manage this risk by entering into natural gas sales contracts with price floors and natural gas and crude oil financial hedges. Our commodity risk management strategy helps to ensure a predictable base level of cash flow, which enhances our ability to execute our drilling and exploration programs, meet debt service requirements and pursue acquisition opportunities despite price fluctuations.

If our revenues decrease significantly as a result of presently unexpected declines in natural gas prices or otherwise, we may curtail our acquisition, development drilling and other activities outside of Canada and secondarily within Canada. We could also be forced to sell some of our assets on an untimely or unfavorable basis.

Forward-Looking Information

Certain statements contained in this annual report and other materials we file with the SEC, as well as information included in oral statements or other written statements made or to be made by us, other than statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements may relate to a variety of matters not currently ascertainable, such as future capital expenditures, drilling activity, acquisitions and dispositions, development or exploratory activities, cost savings efforts, production activities and volumes, hydrocarbon reserves, hydrocarbon prices, hedging activities and the results thereof, financing plans, liquidity, regulatory matters, competition and our ability to realize efficiencies related to certain transactions or organizational changes. Forward-looking statements generally are accompanied by words such as "may," "will," "could," "should," "anticipate," "believe," "budgeted," "expect," "intend," "plan," "project," "potential," "estimate," "continue," or "future" or the negative, other variations thereof or other or similar statements. Although we believe that the expectations reflected in such forward-looking statements are reasonable, no assurance can be given that such expectations will prove correct. Factors that could cause our results to differ materially from the results discussed in such forward-looking statements include:

- changes in general economic conditions;
- fluctuations in crude oil and natural gas prices;
- failure or delays in achieving expected production from oil and gas development projects;
- uncertainties inherent in estimates of oil and gas reserves and predicting oil and gas reservoir performance;
- competitive conditions in our industry;
- actions taken by third-party operators, processors and transporters;
- changes in the availability and cost of capital;
- operating hazards, natural disasters, casualty losses and other matters beyond our control;
- the effects of existing and future laws and governmental regulations;
- the effects of existing or future litigation; and
- certain factors discussed elsewhere in this annual report.

All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this section. The following discussion and analysis should be read in conjunction with "Selected Financial Data" and the consolidated financial statements and notes thereto appearing elsewhere in this annual report.

CRITICAL ACCOUNTING POLICIES

Our financial statements are prepared in accordance with accounting principles generally accepted in the United States of America. The reported financial results and disclosures were determined using significant accounting policies, practices and estimates described below. We believe the reported financial results are reliable and that the ultimate actual results will not differ significantly from those reported.

Oil and Gas Properties

We employ the full cost method of accounting for our oil and gas production assets. Under the full cost method, all costs associated with the acquisition, exploration and development of oil and gas properties are capitalized and accumulated in cost centers on a country-by-country basis. The sum of net capitalized costs and estimated future development and dismantlement costs for each cost center is depleted on the equivalent unit-of-production basis using proved oil and gas reserves as determined by independent petroleum engineers.

Net capitalized costs are limited to the lower of unamortized cost net of related deferred tax or the cost center ceiling. The cost center ceiling is defined as the sum of (i) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on unescalated year-end prices and costs, adjusted for contract provisions and financial derivatives that hedge our oil and gas revenue; (ii) the cost of properties not being amortized; (iii) the lower of cost or market value of unproved properties included in the costs being amortized less (iv) income tax effects related to differences between the book and tax basis of the oil and gas properties. Such limitations are imposed separately for the U.S. and Canadian cost centers.

The ceiling test is affected by a decrease in net cash flow from reserves due to higher operating or finding costs or reduction in market prices for natural gas and crude oil. These changes can reduce the amount of economically producible reserves. At December 31, 2003, the capitalized cost, inclusive of future development costs, for U.S. and Canadian reserves was \$0.70 per Mcfe and \$0.97 per Mcfe, respectively. If the cost center ceiling falls below the capitalized cost for the cost center, we would be required to report an impairment of the cost center's oil and gas assets at the reporting date.

Revenue Recognition

Revenues are recognized when title to the product transfers to purchasers. We follow the "sales method" of accounting for revenue for natural gas and crude oil production, so that we recognize sales revenue on all production sold to purchasers, regardless of whether the sales are proportionate to our ownership in the property. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves. Ultimate revenues from the sales of natural gas and crude oil production is not known with certainty until up to three months after production and title transfer occur. Current revenues are accrued based on our estimate of actual deliveries and actual prices received.

Hedging

We enter into financial derivative instruments to hedge risk associated with the prices received from natural gas and crude oil production and marketing. We also utilize financial derivative instruments to hedge the risk associated with interest rates on our debt outstanding. Every derivative instrument is recorded on our balance sheet as either an asset or liability measured at fair value determined by reference to published future market prices and interest rates. The cash settlement of all derivative instruments is recognized as income or expense in the period in which the hedged transaction is recognized. Gains or losses on derivative instruments terminated prior to their original expiration date are deferred and recognized as income or expense in the period in which the hedged transaction is recognized. The ineffective portion of hedges is recognized currently in earnings.

Portions of our hedge derivatives were classified as current based upon the maturity of the derivative instruments. Based upon the estimated fair values of those hedge derivatives as of December 31, 2003, our revenues for 2004 will decrease approximately \$31.8 million and interest expense will increase approximately \$0.8 million. Net income, after income taxes will be approximately \$21.2 million lower. These amounts will be reclassified from accumulated other comprehensive income in 2004.

Site Dismantlement and Asset Retirement Obligations

We have significant obligations to remove equipment and restore land at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells and associated production facilities. We adopted Statement of Financial Accounting Standard ("SFAS") No. 143, *Accounting for Asset Retirement Obligations"* effective January 1, 2003. Under SFAS No. 143, the estimated fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets is recorded in the periods in which it is incurred. When the liability is recorded, we increase the carrying amount of the related long-lived asset. The liability is accreted to the fair value at the time of the settlement over the useful life of the asset, and the capitalized cost is depleted or depreciated over the useful life of the related asset. The fair value of the liability associated with these retirement obligations is based upon estimates of the current costs to settle such obligations discounted using a credit-adjusted risk-free interest rate that considers the estimated date of settlement of those obligations. As a result of the adoption of SFAS No. 143, we recognized asset retirement costs of $10.8 million and asset retirement obligations of $13.3 million and a cumulative-effect adjustment of $2.3 million. The cumulative-effect adjustment of $2.3 million included $1.3 million for additional depletion and depreciation of the asset retirement costs, $2.2 million for accretion of the fair value of the asset retirement obligations and $1.2 million for deferred tax expenses. During 2003, $0.7 million of accretion expense was recognized and included in the $32.1 million of depletion, depreciation and accretion expense reported in the statement of income for the year. Additional asset retirement costs and obligations of $1.2 million were recognized during 2003. These amounts are associated with long-lived assets placed into service in 2003. Asset retirement obligations at December 31, 2003 are $15.2 million, of which $54,000 has been classified as current.

Income Taxes

Deferred income taxes are established for all temporary differences between the book and the tax basis of assets and liabilities. In addition, deferred tax balances must be adjusted to reflect tax rates that will be in effect in years in which the temporary differences are expected to reverse. MGV, the Company's Canadian subsidiary, computes taxes at rates in effect in Canada. U.S. deferred tax liabilities are not recognized on profits that are expected to be permanently reinvested by MGV and thus are not considered available for distribution to the parent Company.

Included in our net deferred tax liability are $54.1 million of future tax benefits from prior unused tax losses. Realization of these tax assets depends on sufficient future taxable income before the benefits expire. We believe we will have sufficient future taxable income to utilize the loss carry forward benefits before they expire; however, if not, we could be required to recognize a loss for some or all of these tax assets. Net operating loss carry forwards and other deferred tax assets are reviewed annually for recoverability, and are recorded, net of a valuation allowance, if necessary.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements, special purpose entities, financing partnerships or guarantees. The companies in which we have an equity investment do not have any debts.

RESULTS OF OPERATIONS

Summary Financial Data
Year Ended December 31, 2003 Compared with December 31, 2002

	Years Ended December 31, 2003	2002
	(in thousands)	
Total operating revenues	$140,949	$121,979
Total operating expenses	93,782	81,477
Operating income	48,498	40,702
Income before accounting change	18,505	13,835
Net income	16,208	13,835

Net income for 2003 was $16.2 million ($0.71 per diluted share) compared to net income of $13.8 million ($0.68 per diluted share) for 2002. Included in 2003 was a $2.3 million charge ($0.10 per diluted share), net of tax, for the adoption of SFAS No. 143, *Accounting for Asset Retirement Obligations*, as of January 1, 2003. The

2003 period also included a $3.8 million pre-tax charge ($2.5 million after tax) to interest expense as a result of our early redemption of $53 million in principal amount of our subordinated notes payable.

Operating Revenues

Total revenues for 2003 were $141.0 million, a $19.0 million increase from the $122.0 million reported in 2002. Higher realized prices and additional sales volumes increased revenue $26.7 million. Realized sales prices increased 21%. Additional sales volumes were primarily associated with the Enogex interests purchased in December 2002 and the CBM development projects in Canada. Other revenue for 2003 was $7.8 million lower from the prior year. Revenue of $5.1 million was recognized from the sale of Section 29 tax credits in 2002. The tax credits expired in 2002. In 2003, other revenue was reduced by $0.5 million as a result of the completion of our negotiations to purchase the tax credit properties.

Gas, Oil and NGL Sales

Our sales volumes, revenues and average prices for the years ended December 31, 2003 and 2002 are as follows:

	Years Ended December 31,	
	2003	**2002**
Average daily sales volume		
Natural gas—Mcfd		
United States	86,608	87,425
Canada	8,011	2,563
Total	94,619	89,988
Crude oil—Bbld		
United States	2,212	2,479
Canada	1	—
Total	2,213	2,479
NGL—Bbld		
United States	365	426
Canada	4	—
Total	369	426
Total sales—Mcfed		
United States	102,073	104,858
Canada	8,042	2,563
Total	110,115	107,421
Natural gas, oil and NGL sales (in thousands)		
United States	$127,339	$110,263
Canada	11,698	2,033
Total natural gas, oil and NGL sales	$139,037	$112,296
Product sale revenues (in thousands)		
Natural gas sales	$116,563	$ 90,289
Crude oil sales	19,576	19,679
NGL sales	2,898	2,328
Total oil, gas and NGL sales	$139,037	$112,296
Unit prices—including impact of hedges		
Natural gas—per Mcf		
United States	$ 3.32	$ 2.77
Canada	3.98	2.13
Consolidated	3.38	2.75
Crude oil—per Bbl		
United States	$ 24.23	$ 21.74
Canada	24.46	—
Consolidated	24.23	21.74
NGL—per Bbl		
United States	$ 21.45	$ 14.97
Canada	26.01	—
Consolidated	21.50	14.97

Natural gas sales increased $26.3 million from 2002 to $116.6 million for 2003. Our average realized natural gas price increased 23% to $3.38 per Mcf for 2003 and increased revenue $20.6 million. Volumes increased 1,690,000 Mcf from 2002 to 2003 and increased sales $5.7 million. Sales volumes for 2003 increased approximately 5,856,000 Mcf as a result of our drilling programs in the U.S. and Canada. Sales volumes from our Canadian CBM projects, which started production in January 2003, were approximately 2,113,000 Mcf for 2003. U.S. sales volumes increased 2,434,000 Mcf as a result of the additional interests in Michigan properties purchased from Enogex in December 2002. New wells drilled in the Michigan Antrim and Indiana New Albany formations increased sales volumes 1,071,000 Mcf and 239,000 Mcf, respectively. These increases were offset by curtailments in sales volumes as a result of extremely cold weather in the first quarter of 2003 and shutdowns of third party processing plants and pipelines in the second through fourth quarters of 2003. These events reduced sales volumes by approximately 260,000 Mcf and 814,000 Mcf, respectively. Additionally, March through September 2003 sales from our Indiana properties were curtailed when our local end-user reduced its deliveries of gas by approximately 161,000 Mcf. The remaining decreases were the result of natural decline in production from our natural gas wells.

Crude oil sales were $19.6 million for 2003 compared to $19.7 million in 2002. The $2.49 increase in our average realized crude oil price increased revenue $2.3 million which was nearly offset by the decrease in oil sales volumes for 2003. The 11% decrease in sales volumes to 808,000 barrels for the year was the result of an approximately 20,300 barrel decrease due to the sale of Wyoming and Texas oil properties in June 2002 and natural production declines. These reductions were partially offset by a full year's production from wells drilled in the Beaver Creek Detroit River Zone 3 development that increased sales volumes 31,800 barrels.

NGL sales for 2003 increased $0.6 million to $2.9 million. NGL prices increased $6.53 from 2002 to $21.50 and resulted in a $1.0 million increase in revenue that was partially offset by a decrease in sales volumes.

Other Revenues

Other revenue in 2003 consisted of revenue from the marketing, transportation and processing of natural gas. In 2002, other revenue also included revenue of $5.1 million from the sale of Section 29 tax credits. The tax credits expired in 2002. In 2003, other revenue was reduced by $0.5 million as a result of the completion of our negotiations to purchase the tax credit properties. Natural gas marketing, transportation and processing revenue for 2003 was $2.5 million as compared to $4.6 million in 2002. Marketing revenue in 2003 decreased $1.8 million from 2002 primarily as a result of pipeline delivery imbalances that occurred during 2003. Repayments of those imbalances required the purchase of natural gas when natural gas prices had increased from the time in which the imbalances occurred resulting in marketing margin losses.

Operating Expenses

Operating expenses were $93.8 million in 2003 compared to $81.5 million for 2002. The increase was the result of additional sales volumes.

Oil and Gas Production Costs

	Years Ended December 31,	
	2003	2002
	(in thousands, except per unit amounts)	
Production expenses		
United States	$48,243	$40,505
Canada	3,951	1,723
	$52,194	$42,228
Production expenses—per Mcfe		
United States	$ 1.29	$ 1.06
Canada	1.35	1.84
Consolidated	1.30	1.08

Oil and gas production costs for 2003 were $52.2 million compared to 2002 expense of $42.2 million. Production taxes were $3.0 million higher as a result of higher sales volumes and higher average natural gas and crude oil prices in 2003. Canadian production expenses, excluding production taxes of $0.3 million, increased $1.9 million. Canadian production increased approximately 2,000,000 Mcf primarily as a result of the start-up of production from our CBM projects in January of 2003. Although absolute Canadian production expense increased, expense per Mcfe, including production taxes, decreased $0.49 to $1.35 per Mcfe for 2003 as a result of 2003 CBM production.

Production expenses for U.S. properties increased $5.0 million, excluding production tax increases of $2.7 million. Notable production expense increases included $3.1 million of additional expense associated with natural gas volumes produced from the acquired Enogex interests, $0.8 million resulting from settlement costs for post-production cost allowances in Michigan and environmental issues in Indiana and Michigan. Inventory losses, primarily in Indiana, increased expense $0.3 million in 2003. Additional operating expenses of approximately $0.8 million were primarily due to the start-up of producing wells in Indiana during the fourth quarter.

Depletion, Depreciation and Accretion

	Years Ended December 31,	
	2003	**2002**
	(in thousands, except per unit amounts)	
Depletion	$27,379	$26,953
Depreciation of other fixed assets	3,949	3,206
Accretion	739	—
Total depletion, depreciation and accretion	$32,067	$30,159
Average depletion cost per Mcfe	$ 0.68	$ 0.69

Depletion increased $0.4 million to $27.4 million in 2003. Increased depletion was the result of higher sales volumes partially offset by a slight decrease in our consolidated depletion rate. Additional depreciation of $0.7 million was primarily the result of additions to processing and transportation assets including the Cardinal Pipeline which began operations in September 2003. Accretion expense of $0.7 million in 2003 was the result of the adoption of SFAS No. 143 as of January 1, 2003.

General and Administrative Expenses

General and administrative expenses were $8.1 million for 2003 and $0.6 million higher than 2002 general and administrative expenses. The increase is primarily the result of $0.7 million in additional bonuses earned in 2003 and $0.3 million due to the addition of management personnel in the last half of the year. Professional fees were $0.2 million higher than in 2002 and were related to the use of additional engineering and accounting services. These increases were partially offset by the $0.3 million reduction in expense for contract labor in 2003.

Income from Equity Affiliates

Income from equity affiliates increased $1.1 million from the prior year when we recorded losses of $0.8 million associated with Voyager Compression Services LLC. During 2002, Voyager recorded operating losses in addition to an impairment of its assets and lease termination costs in conjunction with ending its operations.

Interest Expense

Interest expense was $20.2 million in 2003. Interest expense for 2003 included a charge of $3.8 million as a result of the early redemption of $53.0 million in principal amount of our subordinated notes payable through the issuance of $70.0 million in principal amount of second lien notes. The $3.8 million charge consisted of a prepayment premium of $3.2 million and remaining deferred financing costs of $1.5 million partially offset by an associated deferred hedging gain of $0.9 million. Ongoing interest expense decreased $2.8 million as a result of a significant decrease in our effective interest rates that was partially offset by an increase in our average debt outstanding in 2003. The interest rates paid on our debt were lower in 2003 because of lower LIBOR rates and the refinancing of our subordinated notes payable through the issuance of our new second lien notes which decreased the associated interest rate approximately 8.3%.

Income Taxes

	Years Ended December 31,	
	2003	**2002**
Income tax provision (in thousands)	$9,997	$7,498
Effective tax rate	35.1%	35.2%

The income tax provision of $10.0 million was established using an effective U.S. federal tax rate of 35%. The provision also includes $1.7 million for Canadian federal and provincial income tax expense. Canadian income tax expense includes consideration of tax rate reductions that were enacted during 2003. Income tax expenses increased from the prior year as a result of higher 2003 pretax income as compared to 2002.

Summary Financial Data
Year Ended December 31, 2002 Compared with December 31, 2001

	Years Ended December 31,	
	2002	**2001**
	(in thousands)	
Total operating revenues	$121,979	$141,963
Total operating expenses	81,477	89,681
Operating income	40,702	53,407
Net income	13,835	19,310

Net income of $13.8 million ($0.68 per diluted share) was recorded for 2002, a decrease of 28% over 2001 net income of $19.3 million ($1.00 per diluted share). The decrease was largely the result of an 8% drop in 2002 realized prices. The sales price decreases were only partially offset by a 20% decrease in production expense for 2002.

Operating Revenues

Total revenues for 2002 were $122.0 million, a $20.0 million decrease from the $142.0 million reported in 2001. Realized sales prices decreased 8%. This decrease, along with a decrease in crude oil volumes, decreased production revenue $13.0 million from the 2001 period. Other revenue was $6.9 million lower primarily due to a decrease in deferred revenue recognition from the sale of Section 29 tax credits and the one-time receipt of revenue associated with a bankruptcy settlement in 2001.

Gas, Oil and NGL Sales

Our sales volumes, revenues and average prices for the years ended December 31, 2002 and 2001 are as follows:

	Years Ended December 31, 2002	2001
Average daily sales volume		
Natural gas—Mcfd		
United States	87,425	87,166
Canada	2,563	2,393
Total	89,988	89,559
Crude oil—Bbld		
United States	2,479	2,902
Canada	—	—
Total	2,479	2,902
NGL—Bbld		
United States	426	525
Canada	—	8
Total	426	533
Total sales—Mcfed		
United States	104,858	107,725
Canada	2,563	2,445
Total	107,421	110,170
Natural gas, oil and NGL sales (in thousands)		
United States	$110,263	$123,077
Canada	2,033	2,268
Total natural gas, oil and NGL sales	$112,296	$125,345
Product sale revenues (in thousands)		
Natural gas sales	$ 90,289	$ 99,183
Crude oil sales	19,679	22,275
NGL sales	2,328	3,887
Total oil, gas and NGL sales	$112,296	$125,345
Unit prices—including impact of hedges		
Natural gas—per Mcf		
United States	$ 2.77	$ 3.05
Canada	2.13	2.47
Consolidated	2.75	3.03
Crude oil—per Bbl		
United States	$ 21.74	$ 21.03
Canada	—	—
Consolidated	21.74	21.03
NGL—per Bbl		
United States	$ 14.97	$ 19.97
Canada	—	21.76
Consolidated	14.97	19.97

Natural gas sales decreased $8.9 million from 2001 to $90.3 million for 2002. The $0.28 per Mcf decrease in average natural gas prices accounted for the entire revenue decrease. Sales volumes for 2002 were slightly higher than 2001 sales volumes. In 2001, sales volumes of 540,000 Mcf were attributable to prior year production payouts identified during 2001. These 2001 payout volumes were offset by approximately 696,000 Mcf of additional 2002 net sales volumes. Significant production increases in Michigan included 646,000 Mcf from Sturgeon Valley Ranch where 15 wells were drilled in late 2001 and at Garfield Field where PdC wells were fracture stimulated between February and June of 2002, resulting in production increases of 306,000 Mcf. Drilling in Indiana resulted in additional production of 132,000 Mcf. Production in 2002 also included 252,000 Mcf from the interests purchased from Enogex Exploration Corporation in December 2002. These increases were partially offset by natural production declines on existing production. In 2002, we drilled 104 net productive wells excluding Canadian wells. We successfully worked over or recompleted a total of 20 net wells during 2002.

Oil sales were $19.7 million for 2002 compared to $22.3 million in 2001. Sales volumes for 2002 decreased 154,000 barrels from 2001 total crude oil production, decreasing oil sales $3.4 million. Higher realized oil prices offset the sales volume decline by $760,000 over the prior year. We sold oil properties located in Wyoming and Texas in June and July of 2002. These property sales resulted in a decrease of approximately 21,000 barrels as compared to 2001.

NGL sales for 2002 decreased $1.6 million to $2.3 million. The decrease was primarily the result of lower NGL prices for 2002.

Other Revenues

Other revenue in 2002 consisted of revenue associated with Section 29 tax credits and with marketing, transportation and processing of natural gas. Revenue derived from Section 29 tax credit monetizations decreased $5.8 million from 2001. Deferred revenue recognition associated with the 2000 tax credit monetization ceased during 2002. Natural gas marketing, transportation and processing revenue for 2002 was $3.0 million as compared to $3.6 million in 2001. The decrease was due primarily to lower gas marketing margins and less marketed volumes in 2002. Other revenue in 2002 also decreased due to the one-time receipt of $0.6 million of revenue recognized in 2001 as a result of a bankruptcy settlement.

Operating Expenses

Operating expenses were $81.5 million in 2002 compared to $89.7 million for 2001. The decrease was the result of lower sales volumes, including the absence of 2001 payout volumes, and cost reduction measures we instituted early in 2002 resulting in a decrease in lease operating expense and production overhead of $4.0 million. Additional expense recoveries of $3.5 million were the result of review of various operating agreements under which we operate both oil and gas properties and other partnerships. The review resulted in an increase of expenses recovered from the oil and gas properties and partnerships. In 2001, we recovered a $1.1 million provision for doubtful accounts associated with the receipt of a bankruptcy settlement.

Oil and Gas Production Costs

	Years Ended December 31,	
	2002	2001
	(in thousands, except per unit amounts)	
Production expenses		
United States	$40,505	$50,967
Canada	1,723	1,738
	$42,228	$52,705
Production expenses—per Mcfe		
United States	$ 1.06	$ 1.28
Canada	1.84	1.95
Consolidated	1.08	1.31

Oil and gas production costs for 2002 were $42.2 million compared to 2001 expense of $52.7 million. Production costs, excluding production taxes and expense recoveries, were $4.0 million lower in 2002. Lower 2002 production volumes decreased production costs $1.3 million. In early 2002, we instituted cost reduction measures that resulted in a $2.7 million decrease in production expenses. Production taxes were $2.3 million lower as a result of lower sales volumes and lower average natural gas and crude oil prices in 2002.

Additional expense recoveries of $4.3 million were recorded in 2002. A review of the operating agreements under which we operate both oil and gas properties and partnerships resulted in an additional $3.5 million of expense recoveries. Beginning in the fourth quarter of 2002, we brought the compressor maintenance function in-house on our operated compressor facilities. Additional 2002 expense recoveries associated with compressor maintenance were $0.8 million.

Depletion and Depreciation

	Years Ended December 31,	
	2002	2001
	(in thousands, except per unit amounts)	
Depletion	$26,953	$26,162
Depreciation of other fixed assets	3,206	2,481
Total depletion and depreciation	$30,159	$28,643
Average depletion cost per Mcfe	$ 0.69	$ 0.65

Depletion increased $790,000 to $27.0 million in 2002. A higher depletion rate increased 2002 depletion $1.5 million, but this was partially offset by a $690,000 decrease due to lower production volumes. Depreciation increased $725,000 to $3.2 million in 2002 primarily as a result of gas compression assets added in 2002.

General and Administrative Expenses

General and administrative expenses were $7.6 million for 2002 and comparable to 2001 general and administrative expenses. Legal expenses increased $450,000 primarily as a result of legal fees incurred for defense of a royalty lawsuit filed against us in late 2001. The increase was offset by decreases in stock exchange fees, board of directors' fees, professional engineering fees and several other expense categories. Stock exchange fees for 2001 included $136,000 for our initial listing on the New York Stock Exchange. No expense for directors' fees was recognized for 2002, as the directors were compensated with stock options accounted for under APB Opinion No. 25 and FASB Interpretation No. 44.

Income from Equity Affiliates

Income from equity affiliates decreased $925,000 from the prior year due primarily to losses of $796,000 associated with Voyager Compression Services LLC. During 2002, Voyager recorded operating losses in addition to an impairment of its assets and lease termination costs in conjunction with ending its operations.

Interest Expense and Other Income/ Expense

Interest expense of $19.8 million in 2002 decreased $3.9 million from 2001. The decrease reflects a significant decrease in our effective interest rates partially offset by an increase in our average debt outstanding in 2002.

Income Taxes

	Years Ended December 31,	
	2002	2001
Income tax provision (in thousands)	$7,498	$10,800
Effective tax rate	35.2%	35.9%

The income tax provision of $7.5 million was established using an effective U.S. federal tax rate of 35%. The 2002 current benefit of $262,000 consists of a refund of federal alternative minimum tax of $178,000 and a state income tax benefit of $139,000 partially offset by Canadian Large Corporation tax expense of $55,000. Income tax expenses decreased from the prior year as a result of lower 2002 pretax income as compared to 2001.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of cash during 2003 were: cash provided by operations; the issuance of common stock in a public offering in August; and proceeds from the issuance of second lien notes in June. Primary cash outflows for the year were capital expenditures and the repayment of debt.

Operating income from the production and sale of oil and natural gas (production revenue less production expense) contributed $16.8 million of the $19.0 million increase in cash from operating activities. The increase was the result of a 3% increase in sales volumes and a 21% increase in sales prices for 2003. Cash from operations includes the $3.2 prepayment premium paid for the early redemption of $53 million in principal amount of our subordinated notes in June 2003.

Our principal operating sources of cash include sales of natural gas, crude oil and NGLs and revenues from natural gas transportation and processing. We sold approximately 74% and 85% of our 2003 natural gas and crude oil production, respectively, under long-term contracts with price floors and financial hedges. As a result, we benefit from significant predictability of our natural gas and crude oil revenues. However, when natural gas and crude oil market prices exceed our financial hedge swap prices, we are required to make payment for the settlement of our hedge derivatives on the fifth day of the production month for natural gas hedges and the fifth day after the production month for crude oil hedges. We do not receive market price cash payment from our customers until 25 to 60 days after the month of production. Additionally, in the event of a significant production curtailment, we are required contractually to fulfill our commitments under our long-term sales contracts by purchasing natural gas volumes at market prices. During the first quarter of 2003, we increased borrowings under our credit facility in part as the result of settlement of our hedge derivatives for the months of January through March.

Cash used in investing activities was $147.4 million for 2003, an increase of $63.8 million from 2002. Capital expenditures increased $59.5 million for 2003 compared to 2002.

Capital expenditures

	United States	Canada	Consolidated
2003			
Proved acreage	$ 3,215	$ 3,388	$ 6,603
Unproved acreage	24,063	6,739	30,802
Development costs	37,682	41,820	79,502
Exploration costs	9,411	17,066	26,477
Gas processing, transportation and administrative	4,820	284	5,104
Total	$79,191	$69,297	$148,488
2002			
Proved acreage	$32,199	$ —	$ 32,199
Unproved acreage	550	5,422	5,972
Development costs	34,178	938	35,116
Exploration costs	5,925	8,659	14,584
Gas processing, transportation and administrative	952	142	1,094
Total	$73,804	$15,161	$ 88,965

Our 2003 capital expenditures for our exploration and production operations were focused in four areas. Expenditures for Canadian exploration and development were approximately $69.0 million. Those expenditures continued exploration and development in the Gayford and Beiseker CBM projects as well as exploration of several other CBM projects. Included in the $69.0 million of Canadian expenditures was $6.7 million for acquisition of additional acreage in several areas. We spent approximately $24.6 million for continued development of our Michigan properties. Expansion of our properties in southern Indiana and northern Kentucky accounted for approximately $31.8 million of our expenditures on exploration and development activities and includes $10.9 million used to acquire additional unproved acreage. An additional $4.0 million was expended for the construction of the Cardinal Pipeline, which transports natural gas from our Indiana properties to an interstate pipeline in Kentucky. We also spent approximately $12.6 million to acquire a significant acreage position in north central Texas where we will be testing and evaluating the Barnett Shale formation in 2004.

As of December 31, 2003 and 2002, our total capitalization was as follows:

	Year ended December 31,	
	2003	2002
	(in thousands)	
Long-term and short-term debt:		
Notes payable to banks	$178,000	$192,000
Second mortgage notes payable	70,000	—
Subordinated notes payable	—	53,000
Mercury note payable	—	1,920
Various loans	1,386	1,582
Fair value interest hedge	50	942
Total debt	249,436	249,444
Stockholders' equity	241,816	128,905
Total capitalization	$491,252	$378,349

Net cash provided by financing activities for 2003 was $79.4 million. On June 27, 2003, we redeemed $53 million in principal amount of our subordinated notes payable through the issuance of $70 million in principal amount of second lien notes. The $3.2 million prepayment premium paid in connection with the refinancing was included in interest expense for the year and is included in cash from operations. On August 26, 2003, we issued 3.5 million shares of common stock for $79.2 million, net of issuance costs.

Our credit facility is a three-year revolving facility that matures on May 15, 2005 and permits us to obtain revolving credit loans and to issue letters of credit for our account from time to time in an aggregate amount not to exceed the lesser of the borrowing base or $250 million. The current borrowing base is $250 million and is subject to semi-annual redetermination and certain other redeterminations based upon several factors. Scheduled redeterminations occur on May 1 and November 1 of each year. Our borrowing base is impacted primarily by the fair value of our oil and gas reserves. Changes in the fair value of our oil and gas reserves are affected by prices for natural gas and crude oil, operating expenses and the results of our drilling activity. A significant decline in the fair value of our reserves could reduce our borrowing base. A borrowing base reduction could limit our ability to carry out our capital expenditure programs and possibly require the repayment of a portion of our current bank borrowings.

At our option, loans may be prepaid, and revolving credit commitments may be reduced in whole or in part at any time in minimum amounts. As of year-end, we can designate the interest rate on amounts outstanding at either the London Interbank Offered Rate (LIBOR)+1.50% or bank prime. The collateral for the credit facility consists of substantially all of our existing assets and any future reserves acquired. The loan agreements prohibit the declaration or payment of dividends by us and contain other restrictive covenants, which, among other things, require the maintenance of a minimum current ratio (calculated in accordance with provisions of the loan agreements) of at least 1.0. At December 31, 2003, we were in compliance with all such restrictions. At December 31, 2003, we had $70.5 million available under the credit facility.

We also have $70 million of Second Mortgage Notes outstanding at December 31, 2003. These notes are a combined LIBOR based variable rate and 7.5% fixed rate interest commitment with a termination date of December 31, 2006. A total of $30 million of the $70 million Second Mortgage Notes accrue interest at a variable rate based upon three-month LIBOR plus 5.48%. In September, we entered into a fair value interest swap covering the $40 million fixed rate Second Mortgage Notes. The swap converts the debt's 7.5% fixed-rate to a floating six-month LIBOR base rate plus 4.07% through the termination of the notes. In January 2004, the swap position was closed and we received $0.3 million. The gain on the swap settlement will be amortized through the original contractual termination date of the swap, December 31, 2006. The Second Mortgage Notes contain restrictive covenants that, among other things, require maintenance of a minimum current ratio of at least 1.0 (calculated in each case in accordance with provisions of the Second Mortgage Notes), a collateral coverage ratio and an earnings ratio before interest, taxes, depreciation and amortization and non-cash income and expense. At December 31, 2003, we were in compliance with such restrictions.

We believe that our capital resources are adequate to meet the requirements of our business. We anticipate our 2004 capital expenditure budget of approximately $157 million will be funded by cash flow from operations, credit facility utilization and the possible issuance of common stock. If capital resources are inadequate or unavailable, we may curtail our acquisition, development and exploration drilling and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

Contractual Obligations and Commercial Commitments

Information regarding our contractual obligations (within the scope of Item 303(a)(5) of Regulation S-K) as of December 31, 2003 is set forth in the following table. At December 31, 2003, we did not have any capital lease obligations or other material purchase obligations that were binding on us and that specified all significant terms. Other long-term liabilities constituting contractual obligations reflected on our balance sheet at December 31, 2003 consisted of derivative obligations and asset retirement obligations.

	Payments Due by Period				
Contractual Obligations	**Total**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**After 5 Years**
			(in thousands)		
Long-Term Debt	$249,436	$ 339	$249,097	$ —	$ —
Derivative Obligations	43,016	33,404	9,612	—	—
Asset Retirement Obligations	15,189	54	119	126	14,890
Gas Purchase Obligations	3,202	2,293	909	—	—
Operating Lease Obligations	6,838	1,432	3,848	1,350	208
Total Obligations	$317,681	$37,522	$263,585	$1,476	$15,098

Long-Term Debt—As of December 31, 2003 we had $178 million outstanding under our credit facility. The remaining long-term debt consists of second lien notes of $70 million and other notes of $1.4 million.

Derivative Obligations—We utilize financial derivatives to manage price risk associated with our natural gas and crude oil product revenue. We also manage interest rate risk associated with our long-term debt. The recorded assets and liabilities associated with our derivative obligations were estimated based on published market prices of natural gas and crude oil for the periods covered by the contracts. Estimates of the liability associated with our interest rate derivative obligations are based upon estimates prepared by our counterparties. These amounts do not necessarily reflect what payments will be made to settle these obligations.

Asset Retirement Obligations—Our liabilities include the fair value, $15.2 million, of asset retirement obligations that result from the acquisition, construction or development and the normal operation of our long-lived assets.

Gas Purchase Obligations—Cinnabar, our subsidiary which ceased operations January 1, 2004, previously contracted to purchase natural gas through May 2005 for resale on the open market. Quicksilver has assumed the obligation.

Operating Leases—We lease office buildings and other property under operating leases. $4.6 million of our operating lease obligations are with an affiliate of Mercury, which is owned by the Darden family.

Interest Obligations—Based upon our debt outstanding at December 31, 2003, we anticipate interest payments to be approximately $10.6 million. We expect to increase borrowings under our credit facility to fund our capital program throughout 2004. For each additional $10 million in borrowings, annual interest payments will increase by approximately $0.3 million. If our borrowing base were to be fully utilized by year-end 2004, we estimate that interest payments would increase by approximately $1.3 million. Should interest rates increase or decrease by 1%, interest paid on our variable-rate debt of $133 million outstanding at January 13, 2004 would increase or decrease by $1.3 million annually. Interest payments would increase or decrease by a further $0.7 million annually should we utilize all of the $70.5 million available under our credit facility at December 31, 2003.

We have the following commercial commitments as of December 31, 2003.

	Amounts of Commitments Expiration per Period				
Commercial Commitments	**Total Committed**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**After 5 Years**
		(in thousands)			
Standby Letters of Credit	$1,553	$1,553	$—	$—	$—
Total Commitments	$1,553	$1,553	$—	$—	$—

Standby Letters Of Credit—Our letters of credit have been issued to fulfill contractual or regulatory requirements. The majority of these letters are against the credit facility. All letters have an annual renewal option.

Recently Issued Accounting Standards

In June 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 141, *Business Combinations*, which requires the purchase method of accounting for business combinations initiated after June 30, 2001 and eliminated the pooling-of-interests method. In July 2001, the FASB also issued SFAS No. 142, *Goodwill and Other Intangible Assets*, which discontinued the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review for impairment. Intangible assets with a determinable useful life continue to be amortized over that period. The amortization provisions apply to goodwill and intangible assets acquired after June 30, 2001. SFAS Nos. 141 and 142 clarify that more assets should be distinguished and classified between tangible and intangible. We did not change or reclassify contractual mineral rights included in oil and gas properties on the balance sheet upon adoption of SFAS No. 142. We believe the treatment of such mineral rights as tangible assets under the full cost method of accounting for crude oil and natural gas properties is appropriate. An issue has arisen regarding whether contractual mineral rights should be classified as intangible rather than tangible assets. If it is determined that reclassification is necessary, our gross oil and gas properties would be reduced by $74.9 million and $31.1 million and intangible assets would be increased by like amounts at December 31, 2003 and 2002, respectively, representing cost incurred from the effective date of June 30, 2001. The provisions of SFAS Nos. 141 and 142 impact only the balance sheet and associated footnote disclosure. The reclassifications would not affect our cash flows or results of operations.

SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections*, was issued in April 2002. The Statement rescinds SFAS No. 4, *Reporting Gains and Losses from Extinguishment of Debt,* and an amendment of that Statement, SFAS No. 64, *Extinguishments of Debt Made to Satisfy Sinking-Fund Requirements.* As a result of the rescission of SFAS No 4, debt extinguishment will no longer be classified as extraordinary under APB No. 30, *Reporting the Results of Operations—Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions.* We have adopted this statement.

In December 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation—Transition and Disclosure—an amendment of FASB Statement No. 123.* The statement provides alternative methods of transition for voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. We complied with the disclosure requirements in our financial statements for the year ended December 31, 2003.

The FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities,* in April 2003. The statement clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* The statement is effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. We have complied with the provisions in this statement.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity.* The statement establishes standards for the classification and measurement of certain financial instruments with characteristics of both liabilities and equity. The statement is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period after June 15, 2003. We do not believe the provisions in this statement affect the Company's liabilities or equity.

The FASB issued FASB Interpretation No. ("FIN") 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*, in November 2002. The FIN elaborates on the disclosures required by a guarantor in its financial statements under certain guarantees it has issued. It also clarifies, that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. FIN 46, *Consolidation of Variable Interest Entities*, was issued in January 2003 and FIN 46R was issued in December 2003. FIN 46R addresses consolidation by business enterprises of variable interest entities. We have reviewed both Interpretations. Neither FIN has any effect on our financial statements.

ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk

We have established policies and procedures for managing risk within our organization, including internal controls. The level of risk assumed by us is based on our objectives and capacity to manage risk.

Our primary risk exposure is related to natural gas and crude oil commodity prices. We have mitigated the downside risk of adverse price movements through the use of swaps, futures and forward contracts; however, we have also limited future gains from favorable movements.

Commodity Price Risk

We enter into various contracts to hedge our exposure to commodity price risk associated with anticipated future natural gas and crude oil production. These contracts have included physical sales contracts and derivatives including price ceilings and floors, no-cost collars and fixed price swaps. As of December 31, 2003, we sell approximately 25,000 Mcfd and 10,000 Mcfd of natural gas under long-term contracts with floor prices of $2.49 per Mcf and $2.47 per Mcf, respectively, through March 2009. Approximately 28,200 Mcfd of our natural gas production was sold under these contracts during 2003. The remaining 6,800 Mcfd sold under these contracts were third-party volumes controlled by us. These contracts are not considered derivatives, but rather normal sales contracts under SFAS No. 133.

Approximately 38,000 Mcfd of our natural gas production is hedged using fixed price swap agreements at a weighted average price of $2.70 per Mcf. These agreements expire from April 2004 to April 2005. An additional 10,000 Mcfd of our first quarter 2004 natural gas production and 750 Bbld of our 2004 crude oil production is hedged using price collars. As a result of these various contracts, we benefit from significant predictability of our natural gas and crude oil revenues.

The following table summarizes our open financial derivative positions as of December 31, 2003 related to natural gas and crude oil production.

Product	Type	Contract Period	Volume	Weighted Avg Price Per Mcf or Bbl	Fair Value
					(in thousands)
Gas	Collar	Jan 2004-Mar 2004	5,000 Mcfd	$ 6.00 – 7.80	$ 164
Gas	Collar	Jan 2004-Mar 2004	5,000 Mcfd	6.00 – 7.85	166
Gas	Fixed Price	Jan 2004-Mar 2004	5,000 Mcfd	6.85	336
Gas	Fixed Price	Jan 2004-Apr 2004	7,500 Mcfd	2.40	(3,190)
Gas	Fixed Price	Jan 2004-Dec 2004	503 Mcfd	2.39	(406)
Gas	Fixed Price	Jan 2004-Apr 2005	10,000 Mcfd	2.79	(12,565)
Gas	Fixed Price	Jan 2004-Apr 2005	10,000 Mcfd	2.79	(12,601)
Gas	Fixed Price	Jan 2004-Apr 2005	10,000 Mcfd	2.79	(12,601)
Oil	Collar	Jan 2004-Jun 2004	500 Bbld	21.00 – 34.60	(30)
Oil	Collar	Jan 2004-Dec 2004	500 Bbld	21.00 – 29.35	(418)
				Net open positions	$(41,145)

Utilization of our financial hedging program may result in realization of natural gas and crude oil prices varying from market prices that we receive from the sale of natural gas and crude oil. As a result of the hedging programs, revenues from production were lower than if the hedging program had not been in effect by $39.8 million in 2003, $7.4 million in 2002 and $22.1 million in 2001.

Commodity price fluctuations affect our remaining natural gas and crude oil volumes as well as our NGL volumes. Up to 4,500 Mcfd of natural gas is committed at market price through May 2004. Additional natural gas volumes of 16,500 Mcfd are committed at market price through September 2008. During 2003, approximately 5,800 Mcfd of our natural gas production was sold under these contracts. An additional 15,200 Mcfd sold under these contracts were third-party volumes controlled by us.

Based on our 2003 average production and long-term natural gas sales contracts with floor prices of $2.49 per Mcf and $2.47 per Mcf, and our 2003 average production, each $1.00 per Mcf increase/decrease in the price of natural gas would increase/decrease our revenue by approximately $24.3 million. Should additional revenue of $24.3 million be realized, approximately $12.5 million would be required for settlement of our existing fixed price hedges.

Prior to ceasing operations as of January 1, 2004, Cinnabar Energy Services & Trading, LLC, our wholly owned marketing company, also entered into various financial contracts to hedge its exposure to commodity price risk associated with future contractual natural gas sales and purchases of third party volumes. These contracts included either fixed and floating price sales or purchases from third parties. As a result of these firm sale and purchase commitments and associated financial price swaps, the hedge derivatives qualified as fair value hedges. Marketing revenues were higher by $0.3 million in 2003, and lower by $2.2 million and $3.0 million in 2002 and 2001, respectively as a result of hedging activities. Hedge ineffectiveness resulted in $188,000 of net gains, $26,000 of net losses and $48,000 net gains recorded to other revenue for 2003, 2002 and 2001, respectively. The following table summarizes Cinnabar's open financial derivative positions and hedged firm commitments as of December 31, 2003 related to natural gas marketing.

Contract Period	Volume	Weighted Avg Price per Mcf	Fair Value (in thousands)
Natural Gas Sales Contracts			
Jan 2004-Mar 2004	328 Mcfd	$ 5.94	$ (8)
Jan 2004-Mar 2004	329 Mcfd	$ 4.91	(36)
Jan 2004-May 2004	656 Mcfd	$ 5.51	(35)
Jan 2004-Jun 2004	328 Mcfd	$ 6.48	43
Jan 2004-Oct 2004	2,286 Mcfd	$ 5.26	(277)
			(313)
Natural Gas Financial Derivatives			
Jan 2004-Mar 2004	328 Mcfd	Floating Price	$ 13
Jan 2004-Mar 2004	329 Mcfd	Floating Price	35
Jan 2004-May 2004	656 Mcfd	Floating Price	37
Jan 2004-Jun 2004	328 Mcfd	Floating Price	(42)
Jan 2004-Oct 2004	2,368 Mcfd	Floating Price	378
			421
		Total-net	$ 108

The fair value of fixed price and floating price natural gas and crude oil derivatives and associated firm commitments as of December 31, 2003 was estimated based on published market prices of natural gas and crude oil for the periods covered by the contracts. The net differential between the prices in each derivative and commitment and market prices for future periods, as adjusted for estimated basis, has been applied to the volumes stipulated in each contract to arrive at an estimated future value. This estimated future value was discounted on each contract at rates commensurate with federal treasury instruments with similar contractual lives. As a result, the fair value of our derivatives and commitments does not necessarily represent the value a third party would pay to assume our contract positions.

Interest Rate Risk

We manage our exposure associated with interest rates by entering into interest rate swaps. As of December 31, 2003, the interest payments for $75.0 million notional variable-rate debt are hedged with an interest rate swap that converts a floating three-month LIBOR base to a 3.74% fixed-rate through March 31, 2005. Our liability associated with the swap was $2.0 million at December 31, 2003.

On September 10, 2003, we entered into an interest rate swap to hedge the $40.0 million of fixed-rate second lien notes issued on June 27, 2003. The swap converts the debt's 7.5% fixed-rate debt to a floating six-month LIBOR base. Our asset associated with the swap was $50,000 at December 31, 2003. In January 2004, the swap position was cancelled, and we received a cash settlement of $0.3 million that will be recognized over the original maturity date for the swap, December 31, 2006.

Interest expense for the years ended December 31, 2003, 2002 and 2001 was $1.4 million, $2.6 million and $1.3 million higher, respectively, as a result of the interest rate swaps.

If interest rates on our variable interest-rate debt of $133 million, as of January 13, 2004, increase or decrease by one percentage point, our annual pretax income will decrease or increase by $1.3 million.

Credit Risk

Credit risk is the risk of loss as a result of non-performance by counterparties of their contractual obligations. We sell a portion of our natural gas production directly under long-term contracts, and the remainder of our natural gas and crude oil was sold through Cinnabar until December 31, 2003. All such natural gas and crude oil is sold to large trading companies and energy marketing companies, refineries and other users of petroleum products. We also enter into hedge derivatives with financial counterparties. We monitor exposure to counterparties by reviewing credit ratings, financial statements and credit service reports. Exposure levels are limited and parental guarantees are required according to our established policy. Each customer and/or counterparty is reviewed as to credit worthiness prior to the extension of credit and on a regular basis thereafter. In this manner, we reduce credit risk.

While we follow our credit policies at the time we enter into sales contracts, the credit worthiness of counterparties could change over time. In fact, Standard & Poors and Moody's downgraded credit ratings of the parent companies of the two counterparties to our long-term gas contracts in early 2003. Please see "Item 1. Risk Factors."

Performance Risk

Performance risk results when a financial counterparty fails to fulfill its contractual obligations such as commodity pricing or volume commitments. Typically, such risk obligations are defined within the trading agreements. We manage performance risk through management of credit risk. Each customer and/or counterparty is reviewed as to credit worthiness prior to the extension of credit and on a regular basis thereafter.

Foreign Currency Risk

Our Canadian subsidiary uses the Canadian dollar as its functional currency. To the extent that business transactions in Canada are not denominated in Canadian dollars, we are exposed to foreign currency exchange rate risk. While cross-currency transactions are immaterial, the result of a ten percent change in the Canadian-U.S. exchange rate would increase or decrease equity by approximately $9.6 million at December 31, 2003.

ITEM 8. Financial Statements and Supplementary Data

QUICKSILVER RESOURCES INC.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

To the Stockholders of Quicksilver Resources Inc.:

The integrity and consistency of the consolidated financial statements of Quicksilver Resources Inc. (the "Company"), which were prepared in accordance with accounting principles generally accepted in the United States of America, are the responsibility of management and properly include some amounts that are based upon estimates and judgments.

The Company maintains a system of internal accounting controls to provide reasonable assurance, at appropriate cost, that the Company's assets are protected and transactions are properly recorded. Additionally, the integrity of the financial accounting system is based on careful selection and training of qualified personnel, organizational arrangements which provide for appropriate division of responsibilities and communication of established written policies and procedures.

Deloitte & Touche LLP, independent auditors, has audited the consolidated financial statements of the Company. Their report expresses their opinion as to the fair presentation, in all material respects, of the financial statements and is based upon their independent audit conducted in accordance with generally accepted auditing standards.

The Audit Committee, composed solely of independent directors, meets periodically with the independent auditors and representatives of management to discuss auditing and financial reporting matters. In addition, the independent auditors meet periodically with the Audit Committee without management representatives present and have free access to the Audit Committee at any time. The Audit Committee is responsible for appointment of the independent auditors, which is subject to stockholder ratification, and the general oversight review of management's discharge of its responsibilities with respect to the matters referred to above. We believe the Company's internal controls as of and for the year ended December 31, 2003 provide reasonable assurance that the consolidated financial statements are reliable.

/s/ Glenn Darden

Glenn Darden
President and Chief Executive Officer

/s/ Bill Lamkin

Bill Lamkin
Executive Vice President and Chief Financial Officer

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Stockholders of
Quicksilver Resources Inc.
Fort Worth, Texas

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

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

On January 1, 2001, the Company adopted Statement of Financial Accounting Standard No. 133, *Accounting for Derivative Instruments and Certain Hedging Activities.*

As discussed in note 3 to the consolidated financial statements, on January 1, 2003, the Company adopted Statement of Financial Accounting Standard No. 143, *Accounting for Asset Retirement Obligations.*

/s/ Deloitte & Touche LLP

Deloitte & Touche LLP

Fort Worth, Texas
March 15, 2004

QUICKSILVER RESOURCES INC.
CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2003 AND 2002
In thousands, except for share data

	2003	2002
ASSETS		
Current assets		
Cash and cash equivalents	$ 4,116	$ 9,116
Accounts receivable	26,247	21,075
Current deferred income taxes	11,760	9,045
Inventories and other current assets	7,588	5,540
Total current assets	49,711	44,776
Investments in and advances to equity affiliates	9,173	10,219
Properties, plant and equipment—net ("full cost")	604,576	470,078
Other assets	3,474	4,465
	$666,934	$529,538
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current portion of long-term debt	$ 339	$ 951
Accounts payable	17,954	14,931
Accrued derivative obligations	34,577	26,362
Accrued liabilities	27,644	26,210
Total current liabilities	80,514	68,454
Related party debt	—	1,280
Long-term debt	249,097	247,213
Deferred derivative obligations	9,662	26,387
Asset retirement obligations	15,135	234
Deferred income taxes	70,710	57,065
Commitments and contingencies (Note 13)	—	—
Stockholders' equity		
Preferred stock, $0.01 par value, 10,000,000 shares authorized, 1 share issued as of December 31, 2003 and 2002	—	—
Common stock, $0.01 par value, 40,000,000 shares authorized, 27,312,315 and 23,663,447 shares issued as of December 31, 2003 and 2002, respectively	273	237
Paid in capital in excess of par value	194,493	114,113
Treasury stock of 2,578,904 and 2,570,502 shares as of December 31, 2003 and 2002, respectively	(10,299)	(10,099)
Accumulated other comprehensive loss	(17,683)	(34,170)
Retained earnings	75,032	58,824
Total stockholders' equity	241,816	128,905
	$666,934	$529,538

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

QUICKSILVER RESOURCES INC.
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 AND 2001
In thousands, except for per share data

	2003	2002	2001
Revenues			
Oil, gas and NGL sales	$139,037	$112,296	$125,345
Other revenue	1,912	9,683	16,618
Total revenues	140,949	121,979	141,963
Expenses			
Oil and gas production costs	52,194	42,228	52,705
Other operating costs	1,301	1,538	1,734
Depletion and depreciation	32,067	30,159	28,643
Provision for doubtful accounts	87	—	(1,071)
General and administrative	8,133	7,552	7,670
Total expenses	93,782	81,477	89,681
Income from equity affiliates	1,331	200	1,125
Operating income	48,498	40,702	53,407
Other income-net	(186)	(470)	(454)
Interest expense	20,182	19,839	23,751
Income before income taxes	28,502	21,333	30,110
Income tax expense	9,997	7,498	10,800
Income before cumulative effect of change in accounting principle	18,505	13,835	19,310
Cumulative effect of change in accounting principle, net of tax	2,297	—	—
Net income	$ 16,208	$ 13,835	$ 19,310
Other comprehensive loss—net of taxes			
Adoption of SFAS No. 133 at January 1, 2001	—	—	(60,304)
Net derivative settlements	27,037	7,114	15,234
Net change in derivative fair value	(20,939)	(27,237)	31,736
Foreign currency translation adjustment	10,389	(40)	(660)
Comprehensive income (loss)	$ 32,695	$ (6,328)	$ 5,316
Basic net income per common share:			
Income before cumulative effect of change in accounting principle	$ 0.83	$ 0.70	$ 1.03
Cumulative effect of change in accounting principle, net of tax	(0.11)	—	—
Net income	$ 0.72	$ 0.70	$ 1.03
Diluted net income per common share:			
Income before cumulative effect of change in accounting principle	$ 0.81	$ 0.68	$ 1.00
Cumulative effect of change in accounting principle, net of tax	(0.10)	—	—
Net income	$ 0.71	$ 0.68	$ 1.00
Basic weighted average shares outstanding	22,394	19,806	18,664
Diluted weighted average shares outstanding	22,845	20,394	19,221

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

QUICKSILVER RESOURCES INC.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 AND 2001
In thousands, except for share and per share data

	2003	2002	2001
Preferred stock, $0.01 par value, 10,000,000 shares authorized			
Balance at beginning of year	$ —	$ —	$ —
Issuance of 1 share special voting preferred	—	—	—
Balance at end of year: 1 share issued at December 31, 2003, 2002 and 2001	—	—	—
Common stock, $0.01 par value, 40,000,000 shares authorized			
Balance at beginning of year	237	225	223
Issuance of common stock	36	12	2
Balance at end of year: 27,312,315; 23,663,447 and 22,534,875 shares issued at December 31, 2003, 2002 and 2001, respectively	273	237	225
Paid in capital in excess of par value			
Balance at beginning of year	114,113	77,814	75,544
Acquisition of minority interest	—	(189)	(59)
Acquisition of Mercury assets	—	—	396
Acquisition of Voyager Compression Services assets	(515)	—	—
Issuance of common stock	80,994	36,680	1,933
Fair value of options issued	—	229	—
Stock issuance costs	(99)	(421)	—
Balance at end of year	194,493	114,113	77,814
Treasury stock, at cost			
Balance at beginning of year	(10,099)	(14,634)	(14,675)
(Acquisition) reissuance of treasury stock, net	(200)	4,535	41
Balance at end of year: 2,578,904; 2,570,502 and 3,751,852 shares at December 31, 2003, 2002, and 2001, respectively	(10,299)	(10,099)	(14,634)
Accumulated other comprehensive loss			
Deferred losses on hedge derivatives			
Balance at beginning of year	(33,457)	(13,334)	—
Adoption of SFAS No. 133 at January 1, 2001	—	—	(60,304)
Net change during the year related to cash flow hedges	6,098	(20,123)	46,970
Balance at end of year	(27,359)	(33,457)	(13,334)
Deferred foreign exchange adjustment			
Balance at beginning of year	(713)	(673)	(13)
Foreign currency translation adjustment	10,389	(40)	(660)
Balance at end of year	9,676	(713)	(673)
Total accumulated other comprehensive loss	(17,683)	(34,170)	(14,007)
Retained earnings			
Balance at beginning of year	58,824	44,989	25,679
Net income	16,208	13,835	19,310
Balance at end of year	75,032	58,824	44,989
Total stockholders' equity	$241,816	$128,905	$ 94,387

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

QUICKSILVER RESOURCES INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS END DECEMBER 31, 2003, 2002 AND 2001
In thousands

	2003	2002	2001
Operating activities:			
Net income	$ 16,208	$ 13,835	$ 19,310
Charges and credits to net income not affecting cash			
Cumulative effect of accounting change, net of tax	2,297	—	—
Depletion and depreciation	32,067	30,159	28,643
Deferred income taxes	9,736	7,760	10,337
Recognition of unearned revenues	507	(3,678)	(9,396)
Income from equity affiliates	(1,331)	(200)	(1,125)
Amortization of deferred loan costs	2,637	1,239	1,606
Non-cash (gain) loss from hedging activities	(678)	842	(303)
Other	455	169	263
Changes in assets and liabilities			
Accounts receivable	(2,606)	414	10,833
Inventory, prepaid expenses and other	(240)	(852)	(1,877)
Accounts payable	3,055	2,664	(619)
Accrued liabilities and other	946	(8,353)	249
Net cash from operating activities	63,053	43,999	57,921
Investing activities:			
Purchase of properties and equipment	(148,488)	(88,965)	(67,409)
Acquisition of Mercury assets, net of cash balances received	—	—	(157)
Acquisition of Voyager Compression Service assets	(684)	—	—
Distributions and advances from equity affiliates-net	1,649	4,043	290
Proceeds from sale of properties	101	1,263	49
Net cash used for investing activities	(147,422)	(83,659)	(67,227)
Financing activities:			
Notes payable, bank proceeds	114,000	16,000	18,000
Principal payments on long-term debt	(113,116)	(14,912)	(14,618)
Issuance of common stock, net of issuance costs	79,926	40,640	1,895
Payments to acquire treasury stock	—	(316)	(78)
Deferred financing costs	(1,441)	(1,362)	—
Net cash from financing activities	79,369	40,050	5,199
Net increase (decrease) in cash and equivalents	(5,000)	390	(4,107)
Cash and equivalents at beginning of period	9,116	8,726	12,833
Cash and equivalents at end of period	$ 4,116	$ 9,116	$ 8,726

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

QUICKSILVER RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 AND 2001

1. NATURE OF OPERATIONS

Quicksilver Resources Inc. ("Quicksilver") is an independent oil and gas company incorporated in the state of Delaware and headquartered in Fort Worth, Texas. Quicksilver engages in the acquisition, development, exploration, production and sale of natural gas, crude oil and natural gas liquids as well as the marketing, processing and transmission of natural gas. Substantial portions of Quicksilver's reserves are located in Michigan, Indiana and Alberta, Canada. Quicksilver has U.S. offices in Gaylord, Michigan; Corydon, Indiana; Cut Bank, Montana; Casper, Wyoming and a Canadian subsidiary, MGV Energy Inc. ("MGV") located in Calgary, Alberta.

Quicksilver's results of operations are largely dependent on the difference between the prices received for its natural gas and crude oil products and the cost to find, develop, produce and market such resources. Natural gas and crude oil prices are subject to fluctuations in response to changes in supply, market uncertainty and a variety of factors beyond Quicksilver's control. These factors include worldwide political instability, quantity of natural gas in storage, foreign supply of crude oil and natural gas, the price of foreign imports, the level of consumer demand and the price of available alternative fuels. Quicksilver manages a portion of the operating risk relating to natural gas and crude oil price volatility through hedging and fixed price contracts. (see notes 4 and 5)

2. SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The Consolidated Financial Statements include the accounts of Quicksilver and its subsidiaries (collectively, the "Company"). The Company accounts for its ownership in unincorporated partnerships and companies under the equity method of accounting as it has significant influence over those entities, but because of terms of the ownership agreements Quicksilver does not meet the criteria for control which would require consolidation of the entities. The Company also consolidates its pro-rata share of oil and gas joint ventures. All significant inter-company transactions are eliminated.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during each reporting period. Management believes its estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties, which may cause actual results to differ materially from the Company's estimates. Significant estimates underlying these financial statements include the estimated quantities of proved natural gas and crude oil reserves used to compute depletion of natural gas and crude oil properties and the related present value of estimated future net cash flows therefrom (see Supplementary Information beginning on page 78), estimates of current revenues based upon expectations for actual deliveries and prices received, the estimated fair value of financial derivative instruments and the estimated fair value of asset retirement obligations.

Cash and Cash Equivalents

Cash equivalents consist of time deposits and liquid debt investments with original maturities of three months or less.

Accounts Receivable

The Company's customers are natural gas and crude oil purchasers. Each customer and/or counterparty of the Company is reviewed as to credit worthiness prior to the extension of credit and on a regular basis thereafter. Although the Company does not require collateral, appropriate credit ratings are required and parental guarantees are obtained. Receivables are generally due in 30-60 days. When collections of specific amounts due are no longer reasonably assured, an allowance for doubtful accounts is established. During 2003, two purchasers accounted for approximately 17% and 12%, respectively, of the Company's total consolidated natural gas and crude oil sales.

Hedging

The Company enters into financial derivative instruments to hedge price risk for its natural gas and crude oil sales and interest rate risk. Hedging is accounted for in accordance with Statements of Financial Accounting Standards ("SFAS") No. 133, *Accounting for Derivative Instruments and Hedge Activities*, and SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities*, which amended SFAS No. 133 (see note 3). The Company does not enter into financial derivatives for trading or speculative purposes.

All derivatives are recorded on the balance sheet as either an asset or liability measured at fair value. Gains and losses that qualify as hedges are recognized in revenues or interest expense in the period in which the hedged transaction is recognized. Gains or losses on derivative instruments terminated prior to their original expiration date are deferred and recognized as income or expense in the period in which the hedged transaction is recognized. Fair value is determined by reference to published future market prices or interest rates. Ineffective portions of hedges are recognized currently in earnings.

The Company's long-term contracts for delivery of 25,000 Mcfd and 10,000 Mcfd at a floor of $2.49 and $2.47, respectively, through March 2009 are not considered derivatives but rather normal sales contracts under SFAS No. 133. Approximately 6,800 Mcfd of these volumes are third-party volumes controlled by the Company.

Inventories

Inventories consist of well equipment, spare parts and supplies carried on a first-in, first-out basis at the lower of cost or market.

Investments in Equity Affiliates

Income from equity affiliates is included as a component of operating income as the operations of the affiliates are associated with the production, processing and transportation of the Company's natural gas production.

Properties, Plant, and Equipment

The Company follows the full cost method of accounting for oil and gas properties. Accordingly, all costs associated with the acquisition, exploration and development of oil and gas properties, including costs of undeveloped leasehold, geological and geophysical expenses, dry holes, leasehold equipment and overhead charges directly related to acquisition, exploration and development activities, are capitalized. Proceeds received from disposals are credited against accumulated cost except when the sale represents a significant disposal of reserves, in which case a gain or loss is recognized.

The sum of net capitalized costs and estimated future development and dismantlement costs for each cost center is depleted on the equivalent unit-of-production method, based on proved oil and gas reserves as determined by independent petroleum engineers. Excluded from amounts subject to depletion are costs associated with unevaluated properties. Natural gas and crude oil are converted to equivalent units based upon the relative energy content, which is six thousand cubic feet of natural gas to one barrel of crude oil.

Net capitalized costs are limited to the lower of unamortized cost net of deferred tax or the cost center ceiling. The cost center ceiling is defined as the sum of (i) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on unescalated year-end prices and costs, adjusted for contract provisions and financial derivatives that hedge the Company's oil and gas revenue, (ii) the cost of properties not being amortized, (iii) the lower of cost or market value of unproved properties included in the cost being amortized less (iv) income tax effects related to differences between the book and tax basis of the natural gas and crude oil properties. Such limitations are imposed separately for the U.S. and Canadian cost center.

All other properties and equipment are stated at original cost and depreciated using the straight-line method based on estimated useful lives from five to forty years.

Revenue Recognition

Revenues are recognized when title to the products transfer to the purchaser. The Company follows the "sales method" of accounting for its natural gas and crude oil revenue, so that the Company recognizes sales revenue on all natural gas or crude oil sold to its purchasers, regardless of whether the sales are proportionate to the Company's ownership in the property. A receivable or liability is recognized only to the extent that the Company has an imbalance on a specific property greater than the expected remaining proved reserves. As of December 31, 2003 and 2002, the Company's aggregate natural gas and crude oil imbalances were not material to its consolidated financial statements.

Environmental Compliance and Remediation

Environmental compliance costs, including ongoing maintenance and monitoring, are expensed as incurred. Environmental remediation costs, which improve the condition of a property, are capitalized.

Income Taxes

Deferred income taxes are established for all temporary differences between the book and the tax basis of assets and liabilities. In addition, deferred tax balances must be adjusted to reflect tax rates that will be in effect in years in which the temporary differences are expected to reverse. MGV, the Company's Canadian subsidiary, computes taxes at rates in effect in Canada. U.S. deferred tax liabilities are not recognized on profits that are expected to be permanently reinvested by MGV and thus not considered available for distribution to the parent Company. Net operating loss carry forwards and other deferred tax assets are reviewed annually for recoverability, and are recorded, net of a valuation allowance, if necessary.

Disclosure of Fair Value of Financial Instruments

The Company's financial instruments include cash, time deposits, accounts receivable, notes payable, accounts payable, long-term debt and financial derivatives. The fair value of long-term debt is estimated at the present value of future cash flows discounted at rates consistent with comparable maturities for credit risk. The carrying amounts reflected in the balance sheet for financial assets classified as current assets and the carrying amounts for financial liabilities classified as current liabilities approximate fair value due to the short maturity of such instruments.

Foreign Currency Translation

The Company's Canadian subsidiary, MGV, uses the Canadian dollar as its function currency. All balance sheet accounts of Canadian operations are translated into U.S. dollars at the year-end rate of exchange and statement of income items are translated at the weighted average exchange rates for the year. The resulting translation adjustments are made directly to a separate component of accumulated other comprehensive income within stockholders' equity. Gains and losses from foreign currency transactions are included in the consolidated statement of income.

Earnings per share

Basic net income or loss per common share is computed by dividing the net income or loss attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income or loss per common share is calculated in the same manner, but also considers the impact to net income and common shares for the potential dilution from stock options, stock warrants and any other outstanding convertible securities.

The following is a reconciliation of the numerator and denominator used for the computation of basic and diluted net income per common share.

	Years Ended December 31,		
	2003	2002	2001
	(in thousands, except per share data)		
Net income	$16,208	$13,835	$19,310
Weighted average common shares—basic	22,394	19,806	18,664
Effect of dilutive securities:			
Stock options	451	559	488
Warrants	—	29	69
Weighted average common shares—diluted	22,845	20,394	19,221
Net income—per share			
Basic	$ 0.72	$ 0.70	$ 1.03
Diluted	0.71	0.68	1.00

Warrants representing 550,000 shares of common stock were excluded from the 2002 and 2001 diluted net income per share computation for the period prior to their exercise as the exercise price exceeded the average market price of the Company's common stock.

Stock-Based Employee Compensation

At December 31, 2003, the Company has one stock-based employee compensation plan, which is described more fully in Note 16. The Company accounts for the plan under the recognition and measurement principles of APB No. 25, *Accounting for Stock Issued to Employees*, and related Interpretations. No stock-based employee compensation cost is reflected in net income, as all options granted under the plan had an exercise price equal to the market value of the underlying common stock on the date of grant. The following table illustrates the effect on net income and earnings per share if the Company had applied fair value recognition provisions of FASB Statement No. 123, *Accounting for Stock-Based Compensation.*

	Years Ended December 31,		
	2003	2002	2001
	(in thousands, except per share data)		
Net income, as reported	$16,208	$13,835	$19,310
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	(436)	(674)	(590)
Pro forma net income	$15,772	$13,161	$18,719
Earnings per share			
Basic—as reported	$ 0.72	$ 0.70	$ 1.03
Basic—pro forma	$ 0.70	$ 0.66	$ 1.00
Diluted—as reported	0.71	0.68	1.00
Diluted—pro forma	0.69	0.65	0.97

Recently Issued Accounting Standards

In June 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 141, *Business Combinations*, which requires the purchase method of accounting for business combinations initiated after June 30, 2001 and eliminated the pooling-of-interests method. In July 2001, the FASB also issued SFAS No. 142, *Goodwill and Other Intangible Assets*, which discontinued the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review for impairment. Intangible assets with a determinable useful life continue to be amortized over that period. The amortization provisions apply to goodwill and intangible assets acquired after June 30, 2001. SFAS Nos. 141 and 142 clarify that more assets should be distinguished and classified between tangible and intangible. The Company did not change or reclassify contractual mineral rights included in oil and gas properties on the balance sheet upon adoption of SFAS No. 142. The Company believes the treatment of such mineral rights as tangible assets under the full cost method of accounting for crude oil and natural gas properties is appropriate. An issue has arisen regarding whether contractual mineral rights should be classified as intangible rather than tangible assets. If it is determined that reclassification is necessary, the Company's gross oil and gas properties would be reduced by $74.9 million and $31.1 million and intangible assets would be increased by like amounts at December 31, 2003 and 2002, respectively, representing cost incurred from the effective date of June 30, 2001. The provisions of SFAS Nos. 141 and 142 impact only the balance sheet and associated footnote disclosure. The reclassifications would not affect the Company's cash flows or results of operations.

SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections*, was issued in April 2002. The Statement rescinds SFAS No. 4, *Reporting Gains and Losses from Extinguishment of Debt*, and an amendment of that Statement, SFAS No. 64, *Extinguishments of Debt Made to Satisfy Sinking-Fund Requirements*. As a result of the rescission of SFAS No 4, debt extinguishment will no longer be classified as extraordinary under APB No. 30, *Reporting the Results of Operations—Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions*. The Company has adopted this statement.

In December 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation—Transition and Disclosure—an amendment of FASB Statement No. 123*. The statement provides alternative methods of transition for voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. The Company complied with the disclosure requirements in our financial statements for the year ended December 31, 2003.

The FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*, in April 2003. The statement clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. The statement is effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. The Company has complied with the provisions in this statement.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*. The statement establishes standards for the classification and measurement of certain financial instruments with characteristics of both liabilities and equity. The statement is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period after June 15, 2003. The Company does not believe the provisions in this statement affect the Company's liabilities or equity.

The FASB issued FASB Interpretation No. ("FIN") 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*, in November 2002. The FIN elaborates on the disclosures required by a guarantor in its financial statements under certain guarantees it has issued. It also clarifies, that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. FIN 46, *Consolidation of Variable Interest Entities*, was issued in January 2003 and FIN 46R was issued in December 2003. FIN 46R addresses consolidation by business enterprises of variable interest entities. The Company has reviewed both Interpretations. Neither FIN has any effect on its financial statements.

3. ASSET RETIREMENT OBLIGATIONS

The FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations*, which is effective for fiscal years beginning after June 15, 2002. This statement, adopted by the Company as of January 1, 2003, establishes accounting and reporting standards for the legal obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction or development and the normal operation of long-lived assets. It requires that the fair value of the liability for asset retirement obligations be recognized in the period in which it is incurred. Upon initial recognition of the asset retirement liability, an asset retirement cost is capitalized by increasing the carrying amount of the long-lived asset by the same amount as the liability. In periods subsequent to initial measurement, the asset retirement cost is allocated to expense using a systematic method over the asset's useful life. Changes in the liability for the asset retirement obligation are recognized for (a) the passage of time and (b) revisions to either the timing or the amount of the original estimate of undiscounted cash flows.

In connection with adoption of SFAS No. 143, all asset retirement obligations of the Company were identified and the fair value of the retirement costs were estimated as of the date the long-lived assets were placed into service. The asset retirement obligations' fair values were then estimated as of January 1, 2003. At January 1, 2003, the Company recognized asset retirement costs of $10.8 million and asset retirement obligations of $13.3 million, of which $0.9 million was classified as current. The cumulative-effect adjustment of $2.3 million included $1.3 million for additional depletion and depreciation of the asset retirement costs,

$2.2 million for accretion of the fair value of the asset retirement obligations and $1.2 million for deferred tax benefits. The asset retirement obligation would have been $12.6 million at January 1, 2002 had FAS No. 143 been in effect.

The following table reflects pro forma income for all periods assuming that SFAS No. 143 was applied retroactively.

	For the Year Ended December 31,		
	2003	2002	2001
	(in thousands)		
Income before cumulative effect of change in accounting principle	$18,505	$13,835	$19,310
Deduct: accretion of asset retirement obligation and depletion and depreciation of associated fixed assets, net of tax effects	—	(523)	(475)
Pro forma net income before cumulative effect of change in accounting principle	$18,505	$13,312	$18,835
Pro forma net income—per share			
Basic	$ 0.83	$ 0.67	$ 1.01
Diluted	0.81	0.65	0.98

The following table provides a reconciliation of the changes in the estimated asset retirement obligation from the amount recorded upon adoption of SFAS No. 143 on January 1, 2003 through December 31, 2003.

	2003
	(in thousands)
Beginning asset retirement obligation	$13,326
Additional liability incurred	999
Accretion expense	739
Asset retirement costs incurred	(39)
Currency translation adjustment	164
Ending asset retirement obligation	$15,189

During the year ended December 31, 2003, accretion expense was recognized and included in the $32.1 million of depletion, depreciation and accretion expense reported in the statement of income for the year. There have not been any revisions to either the timing or the amount of the original estimate of undiscounted cash flows during 2003. Asset retirement obligations at December 31, 2003 are $15.2 million, of which $54,000 has been classified as current.

4. HEDGING

The Company hedges a portion of its equity production of natural gas and crude oil using various financial derivatives. All derivatives are evaluated using the hedge criteria established under SFAS Nos. 133 and 138. If hedge criteria are met, the change in a derivative's fair value (for a cash flow hedge) is deferred in stockholders' equity as a component of accumulated other comprehensive income. These deferred gains and losses are recognized into income in the period in which the hedged transaction is recognized in revenues to the extent the hedge is effective. The ineffective portions of hedges are recognized currently in earnings.

During 2003 and 2002, Cinnabar Energy Services and Trading LLC ("Cinnabar"), the Company's wholly owned marketing subsidiary, entered into both fixed and floating price firm natural gas sale and purchase commitments and associated financial price swaps which extend through November 2004. The derivative transactions qualify as fair value hedges. Hedge ineffectiveness resulted in $188,000 of net gains, $26,000 of net losses and $48,000 of net gains recorded to other revenue in 2003, 2002 and 2001, respectively.

During 2002, the Company cancelled three interest rate swap agreements. The first, covering its $53 million of Second Mortgage Notes ("Subordinated Notes"), was cancelled on July 15, 2002 and the Company received a cash settlement of $1.0 million. The swap agreement converted the debt's 14.75% fixed rate to a floating three-month LIBOR base rate and qualified as a fair value hedge. The Company deferred the $1.0 million settlement, which was to be recognized through the original maturity date for the swap, March 30, 2009. The Company redeemed the $53 million in principal amount of Subordinated Notes in June 2003. At that time the remaining $0.9 million deferred gain was recognized.

In October 2002, the Company cancelled two fixed-rate interest rate swaps related to $75 million of the Company's variable-rate debt and entered into a new fixed-rate interest swap that converted the interest rate to a fixed-rate of 3.74% through March 31, 2005. The fair value of the open swap at its inception was $1.9 million. The Company recognized the $1.9 million loss associated with the cancelled swaps through the original maturity date of the swaps, March 31, 2003. At December 31, 2003, the fair value of the open interest swap was $2.0 million.

On September 11, 2003, the Company entered into a fair value interest swap covering $40 million of its fixed rate 2003 Second Mortgage Notes. The swap converted the debt's 7.5% fixed rate to a floating six-month LIBOR base rate plus 4.07% through the termination of the notes. The fair value of the swap was a gain of $50,000 as of December 31, 2003. In January 2004, the swap position was cancelleded and the Company received a cash settlement of $0.3 million that will be recognized over the original maturity date for the swap, December 31, 2006.

The change in carrying value of the Company's derivatives, firm sale and purchase commitments accounted for as hedges and interest rate swaps in the Company's balance sheet since December 31, 2002 resulted from a decrease in the remaining hedged volumes partially offset by an increase in market prices for natural gas, crude oil and a decrease in interest rates. The change in fair value of all cash flow hedges was reflected in accumulated other comprehensive income, net of deferred tax effects. Natural gas and crude oil derivative assets and liabilities reflected as current in the December 31, 2003 balance sheet represent the estimated fair value of contract settlements scheduled to occur over the subsequent twelve-month period based on market prices for natural gas and crude oil as of the balance sheet date. These settlement amounts are not due and payable until the monthly period that the related underlying hedged gas or oil sales transaction occurs. Settlement of the underlying hedged transactions occurs in the following 20 to 85 days.

The estimated fair values of all derivatives and the associated fixed price firm sale and purchase commitments of the Company as of December 31, 2003 and 2002 are provided below. The associated carrying values of these swaps are equal to the estimated fair values for each period presented.

	December 31, 2003	December 31, 2002
	(in thousands)	
Derivative assets:		
Fixed price purchase commitments	$ —	$ 29
Fixed price sale commitments	43	—
Natural gas financial collars	330	—
Floating price natural gas financial swaps	463	269
Fixed price natural gas financial swaps	336	—
Fixed to floating interest rate swap	50	—
	$ 1,222	$ 298
Derivative liabilities:		
Fixed price natural gas financial swaps	$41,363	$48,560
Fixed price crude oil financial swaps	—	292
Fixed price sale commitments	356	226
Crude oil financial collars	448	379
Floating price natural gas financial swaps	42	382
Floating to fixed interest rate swap	2,030	2,910
	$44,239	$52,749

The fair value of all natural gas and crude derivatives and firm sale and purchase commitments accounted for as hedges as of December 31, 2003 and 2002 was estimated based on market prices of natural gas and crude oil for the periods covered by the derivatives. The net differential between the prices in each derivative and market prices for future periods, as adjusted for estimated basis, has been applied to the volumes stipulated in each contract to arrive at an estimated future value. This estimated future value was discounted on each contract at rates commensurate with federal treasury instruments with similar contractual lives. The fair value of interest rate swaps was based upon counterparty estimates of the fair value of such swaps. As a result, the fair value of the Company's derivatives and commitments does not necessarily represent the value a third party would pay to assume the Company's contract positions. Of the $1.2 million of derivatives assets and $44.2 million of derivative liabilities, $1.2 million of assets and $34.6 million of liabilities have been classified as current at December 31, 2003 based on the maturity of the derivative instruments resulting in $21.1 million of after-tax losses to be reclassified from accumulated other comprehensive income in 2004.

5. FINANCIAL INSTRUMENTS

The Company has established policies and procedures for managing risk within its organization, including internal controls. The level of risk assumed by the Company is based on its objectives and capacity to manage risk.

Quicksilver's primary risk exposure is related to natural gas and crude oil commodity prices. The Company has mitigated the downside risk of adverse price movements through the use of swaps, futures and forward contracts; however, it has also limited future gains from favorable movements.

Commodity Price Risk

The Company enters into contracts to hedge its exposure to commodity price risk associated with anticipated future natural gas and crude oil production. These contracts have included physical sales contracts and derivatives including price ceilings and floors, no-cost collars and fixed price swaps. As of December 31, 2003, Quicksilver sells approximately 25,000 Mcfd and 10,000 Mcfd of natural gas under long-term contracts with a floor of $2.49 per Mcf and $2.47 per Mcf, respectively, through March 2009. Approximately 28,200 Mcfd of the Company's natural gas production was sold under these contracts during 2003. The remaining 6,800 Mcfd sold under these contracts were third-party volumes controlled by the Company. These contracts are not considered derivatives, but rather normal sales contracts under SFAS No. 133.

Approximately 38,000 Mcfd of the Company's natural gas production is hedged using fixed price swap agreements at prices averaging $2.71 per Mcf. These agreements expire from April 2004 to April 2005. An additional 5,000 Mcfd of the Company's first quarter 2004 natural gas production is hedged using a fixed price agreement at a price of $6.85 per Mcf and 10,000 Mcfd of its first quarter 2004 natural gas production is hedged using two price collar agreements. Additionally, 750 Bbld of the Company's 2004 crude oil production is hedged using two price collar agreements. These agreements of 500 Bbld of crude oil production expire in June and December 2004. As a result of these various contracts, the Company benefits from significant predictability of its natural gas and crude oil revenues. The following table summarizes the Company's open financial derivative positions as of December 31, 2003 related to natural gas and crude oil production.

Product	Type	Contract Period	Volume	Weighted Avg Price Per Mcf or Bbl	Fair Value
					(in thousands)
Gas	Collar	Jan 2004-Mar 2004	5,000 Mcfd	$ 6.00 – 7.80	$ 164
Gas	Collar	Jan 2004-Mar 2004	5,000 Mcfd	6.00 – 7.85	166
Gas	Fixed Price	Jan 2004-Mar 2004	5,000 Mcfd	6.85	336
Gas	Fixed Price	Jan 2004-Apr 2004	7,500 Mcfd	2.40	(3,190)
Gas	Fixed Price	Jan 2004-Dec 2004	503 Mcfd	2.39	(406)
Gas	Fixed Price	Jan 2004-Apr 2005	10,000 Mcfd	2.79	(12,565)
Gas	Fixed Price	Jan 2004-Apr 2005	10,000 Mcfd	2.79	(12,601)
Gas	Fixed Price	Jan 2004-Apr 2005	10,000 Mcfd	2.79	(12,601)
Oil	Collar	Jan 2004-Jun 2004	500 Bbld	21.00 – 34.60	(30)
Oil	Collar	Jan 2004-Dec 2004	500 Bbld	21.00 – 29.35	(418)
				Net open positions	$(41,145)

Utilization of the Company's financial hedging program may result in natural gas and crude oil realized prices varying from market prices that the Company receives from the sale of natural gas and crude oil. As a result of the hedging programs, revenues from production in 2003, 2002 and 2001 were $39.8 million, $7.4 million and $22.1 million, respectively, lower than if the hedging program had not been in effect.

Commodity price fluctuations affect the remaining natural gas and crude oil volumes as well as the Company's NGL volumes. Up to 4,500 Mcfd of natural gas is committed at market price through May 2004. Additional natural gas volumes of 16,500 Mcfd are committed at market price through September 2008. During 2003, approximately 5,800 Mcfd of Quicksilver's natural gas production was sold under these contracts. An additional 15,200 Mcfd sold under these contracts were third-party volumes controlled by the Company.

Prior to January 1, 2004, Cinnabar also entered into various financial contracts to hedge its exposure to commodity price risk associated with future contractual natural gas sales and purchases with derivative instruments. Marketing revenues for Cinnabar were $0.3 million higher and lower by $2.2 million and $3.0 million as a result of its hedging activities in 2003, 2002 and 2001, respectively. The following table summarizes Cinnabar's open financial derivative positions and hedged firm commitments as of December 31, 2003 related to natural gas marketing.

Contract Period	Volume	Weighted Avg Price per Mcf	Fair Value
			(in thousands)
Natural Gas Sales Contracts			
Jan 2004-Mar 2004	328 Mcfd	$ 5.94	$ (8)
Jan 2004-Mar 2004	329 Mcfd	$ 4.91	(36)
Jan 2004-May 2004	656 Mcfd	$ 5.51	(35)
Jan 2004-Jun 2004	328 Mcfd	$ 6.48	43
Jan 2004-Oct 2004	2,286 Mcfd	$ 5.26	(277)
			(313)
Natural Gas Financial Derivatives			
Jan 2004-Mar 2004	328 Mcfd	Floating Price	$ 13
Jan 2004-Mar 2004	329 Mcfd	Floating Price	35
Jan 2004-May 2004	656 Mcfd	Floating Price	37
Jan 2004-Jun 2004	328 Mcfd	Floating Price	(42)
Jan 2004-Oct 2004	2,368 Mcfd	Floating Price	378
			421
		Total-net	$ 108

The fair values of fixed price and floating price natural gas and crude oil derivatives and associated firm commitments as of December 31, 2003 were estimated based on market prices of natural gas and crude oil for the periods covered by the contracts. The net differential between the prices in each contract and market prices for future periods, as adjusted for estimated basis, has been applied to the volumes stipulated in each contract to arrive at an estimated future value. This estimated future value was discounted on each contract at rates commensurate with federal treasury instruments with similar contractual lives. As a result, the natural gas and crude oil financial swap and firm commitment fair value does not necessarily represent the value a third party would pay to assume the Company's contract positions.

Interest Rate Risk

The Company manages its exposure associated with interest rates by entering into interest rate swaps. As of December 31, 2003, the interest payments for $75.0 million notional variable-rate debt are hedged with an interest rate swap that converts a floating three-month LIBOR base to a 3.74% fixed-rate through March 31, 2005. The liability associated with the swap is $2.0 million at December 31, 2003.

On September 10, 2003, the Company entered into an interest rate swap to hedge the $40.0 million of fixed-rate second lien notes issued on June 27, 2003. The swap converts the debt's 7.5% fixed-rate debt to a floating six-month LIBOR base. The asset associated with the swap is $50,000 at December 31, 2003. In January 2004, the swap position was closed and the Company received a cash settlement of $0.3 million that will be recognized over the original maturity date for the swap, December 31, 2006.

Credit Risk

Credit risk is the risk of loss as a result of non-performance by counterparties of their contractual obligations. The Company sells a portion of its natural gas production directly under long-term contracts, and the remainder of its natural gas and crude oil is sold to large trading companies and energy marketing companies, refineries and other users of petroleum products. Quicksilver also enters into hedge derivatives with financial counterparties. The Company monitors its exposure to counterparties by reviewing credit ratings, financial statements and credit service reports. Exposure levels are limited and parental guarantees are required according to Company policy. Each customer and/or counterparty of the Company is reviewed as to credit worthiness prior to the extension of credit and on a regular basis thereafter. In this manner, the Company reduces credit risk.

While Quicksilver follow its credit policies at the time it enters into sales contracts, the credit worthiness of counterparties could change over time. In fact, Standard & Poors and Moody's downgraded credit ratings of the parent companies of the two counter parties to the Company's long-term gas contracts in early 2003.

Performance Risk

Performance risk results when a financial counterparty fails to fulfill its contractual obligations such as commodity pricing or volume commitments. Typically, such risk obligations are defined within the trading agreements. The Company manages performance risk through management of credit risk. Each customer and/or counterparty of the Company is reviewed as to credit worthiness prior to the extension of credit and on a regular basis thereafter.

Foreign Currency Risk

The Company's Canadian subsidiary uses the Canadian dollar as its functional currency. To the extent that business transactions in Canada are not denominated in Canadian dollars, the Company is exposed to foreign currency exchange rate risk.

6. ACCOUNTS RECEIVABLE

Accounts receivable consist of the following:

	As of December 31,	
	2003	**2002**
	(in thousands)	
Accrued production receivables	$19,318	$15,861
Joint interest receivables	6,478	4,571
Other receivables	552	658
Allowance for bad debts	(101)	(15)
	$26,247	$21,075

On March 10, 1999, one of the Company's natural gas purchasers filed for protection under Chapter 11 of the Federal Bankruptcy Code. Management determined that a portion of the approximate $2.5 million account receivable associated with the purchaser was not collectable; accordingly, an allowance for doubtful accounts of $1.4 million was established in 1999. The Company recovered $1.4 million during 2000 and an additional $1.7 million during 2001. As a result, $1.1 million and $0.3 million were recorded in 2001 and 2000, respectively, as recoveries of the provision for doubtful accounts. The remaining $0.6 million was recorded to other revenue in 2001.

7. INVENTORIES AND OTHER CURRENT ASSETS

Inventories and other current assets consist of:

	As of December 31, 2003	As of December 31, 2002
	(in thousands)	
Inventories	$4,595	$4,898
Hedge derivatives (see note 4)	1,172	298
Prepaid expenses and deposits	1,821	344
	$7,588	$5,540

8. PROPERTIES AND EQUIPMENT

Property and equipment includes the following:

	As of December 31, 2003	As of December 31, 2002
Oil and gas properties	(in thousands)	
Subject to depletion	$ 665,457	$ 545,378
Unevaluated costs	49,919	16,913
Accumulated depletion	(159,801)	(130,906)
Net oil and gas properties	555,575	431,385
Other equipment		
Pipeline and gathering and processing facilities	56,980	43,674
General properties	7,645	6,425
Accumulated depreciation	(15,624)	(11,406)
Net other property and equipment	49,001	38,693
Property and equipment, net of accumulated depreciation and depletion	$ 604,576	$ 470,078

Unevaluated Natural Gas and Crude Oil Properties Excluded From Depletion

Under full cost accounting, the Company may exclude certain unevaluated costs from the amortization base pending determination of whether proved reserves have been discovered or impairment has occurred. A summary of the unevaluated properties excluded from natural gas and crude oil properties being amortized at December 31, 2003 and 2002 and the year in which they were incurred as follows:

	December 31, 2003 Costs Incurred During					December 31, 2002 Costs Incurred During				
	2003	2002	2001	Prior	Total	2002	2001	2000	Prior	Total
	(in thousands)					(in thousands)				
Acquisition costs	$31,834	$11,658	$903	$1,307	$45,702	$12,329	$903	$2,083	$875	$16,190
Exploration costs	3,337	880	—	—	4,217	723	—	—	—	723
Total	$35,171	$12,538	$903	$1,307	$49,919	$13,052	$903	$2,083	$875	$16,913

Costs are transferred into the amortization base on an ongoing basis, as the projects are evaluated and proved reserves established or impairment determined. Pending determination of proved reserves attributable to the above costs, the Company cannot assess the future impact on the amortization rate. As of December 31, 2003, approximately $22.8 million of the total unevaluated property balance of $49.9 million related to the Company's Canadian coal bed methane projects. These costs will be transferred into the amortization base as the undeveloped projects and areas are evaluated. The Company anticipates that the majority of this activity should be completed over the next two to three years.

Capitalized Costs

Capitalized overhead costs that directly relate to exploration and development activities were $2.2 million, $0.8 million and $0.5 million for the years ended December 31, 2003, 2002 and 2001, respectively.

Depletion per Mcfe was $0.68, $0.69 and $0.65 for the years ended December 31, 2003, 2002 and 2001, respectively.

9. OTHER ASSETS

Other assets consist of:

	As of December 31,	
	2003	2002
	(in thousands)	
Deferred loan costs	$ 6,995	$ 7,876
Less accumulated amortization	(4,634)	(4,319)
Net deferred loan costs	2,361	3,557
Hedge derivatives (see note 4)	50	—
Other	1,063	908
	$ 3,474	$ 4,465

Costs related to the acquisition of debt are deferred and amortized on a straight-line basis over the term of the debt.

10. ACCRUED LIABILITIES

Accrued liabilities include the following:

	As of December 31,	
	2003	2002
	(in thousands)	
Accrued capital expenditures	$10,179	$ 1,299
Accrued product purchases	6,626	6,787
Section 29 property settlement	—	5,743
Suspended revenue	3,577	4,064
Accrued operating expenses	3,552	3,424
Accrued property and production taxes	1,981	2,033
Interest payable	522	2,018
Other	1,207	842
	$27,644	$26,210

11. NOTES PAYABLE AND LONG-TERM DEBT

Long-term debt consists of:

	As of December 31,	
	2003	2002
	(in thousands)	
Notes payable to banks	$178,000	$192,000
Second mortgage notes payable	70,000	—
Subordinated notes payable	—	53,000
Mercury note payable	—	1,920
Other loans	1,386	1,582
Fair value interest hedge	50	942
	249,436	249,444
Less current maturities	(339)	(951)
	$249,097	$248,493

Maturities are as follows, in thousands of dollars:

2004	$ 339
2005	178,330
2006	70,398
2007	369
	$249,436

The Company has a three-year revolving credit facility ("Credit Facility") that matures on May 13, 2005 and permits the Company to obtain revolving credit loans and to issue letters of credit for the account of the Company from time to time in an aggregate amount not to exceed the lesser of the borrowing base or $250 million. The borrowing base as confirmed on November 1, 2003 is $250 million and is subject to semi-annual determination and certain other redeterminations based upon several factors. Scheduled redeterminations occur on May 1 and November 1 of each year. At the Company's option, loans may be prepaid, and revolving credit commitments may be reduced in whole or in part at any time in minimum amounts. As of year-end, the Company can designate the interest rate on amounts outstanding at either the LIBOR + 1.50% or bank prime. At December 31, 2003, the Company's interest rate was 2.67% through March 30, 2004 on $163 million. The collateral for the Credit Facility consists of substantially all of the existing mineral assets of the Company and any future reserves acquired. The loan agreements prohibit the declaration or payment of dividends by the Company and contain other restrictive covenants, which, among other things, require the maintenance of a minimum current ratio (calculated in accordance with provisions of the loan agreements) of at least 1.0. The Company currently is in compliance with all such restrictions. At December 31, 2003, the Company had $70.5 million available under the Credit Facility.

On June 27, 2003, the Company redeemed $53 million in principal amount of subordinated notes payable through the issuance of $70 million in principal amount of second lien notes. As a result of the redemption, the Company recognized additional interest expense of $3.8 million, consisting of a prepayment premium of $3.2 million and remaining deferred financing costs of $1.5 million partially offset by an associated deferred hedging gain of $0.9 million. The new $70 million second lien notes ("Second Mortgage Notes") are a combined LIBOR based variable rate and 7.5% fixed rate interest commitment with a termination date of December 31,

2006. A total of $30 million of the $70 million Second Mortgage Notes will be at the variable rate based upon the three-month LIBOR rate plus 5.48%. The Second Mortgage Notes contain restrictive covenants, which, among other things, require maintenance of a minimum current ratio of at least 1.0 (calculated in each case in accordance with provisions of the Second Mortgage Notes), a collateral coverage ratio and an earnings ratio before interest, taxes, depreciation and amortization and non-cash income and expense. The Company currently is in compliance with all such restrictions. At December 31, 2003, the fair value of the $70 million in principal amount of second lien notes was $70.05 million.

On September 11, 2003, the Company entered into a fair value interest swap covering $40 million of the fixed rate Second Mortgage Notes. The swap converts the debt's 7.5% fixed-rate to a floating six-month LIBOR base rate plus 4.07% through the termination of the notes. At December 31, 2003, valuation of the swap resulted in a $0.05 million increase in the fair value of the Second Mortgage Notes. In January 2004, the swap position was closed, and the Company received $0.3 million. The gain on the swap settlement will be amortized through the original term of the swap, December 31, 2006.

12. TAX CREDIT SALES

Until expiration of the tax credit at December 31, 2002, certain properties of the Company earned Internal Revenue Code Section 29 income tax credits. Code Section 29 allowed a credit against regular federal income tax liability for certain eligible gas production.

On March 31, 2000, the Company conveyed, to a bank, Section 29 tax credits for 99.5% of interests interests in Devonian production from certain wells located in Michigan acquired from CMS Oil and Gas Co. incuding Terra Energy Ltd. Cash proceeds received from the sale were $25 million and were recorded as unearned revenue. Revenue was recognized as reserves were produced. The purchase and sale agreement and ancillary agreements with the bank included a production payment in favor of Quicksilver burdening future production on the properties. Revenue of $3.7 million and $9.4 million was recognized in 2002 and 2001, respectively, in other revenue. During 1997, other tax credits attributable to properties owned by the Company were conveyed through the sale of certain working interests to a bank by entities who contributed properties to the Company at the time of its formation. Revenue of $1.4 million and $1.5 million was recognized in 2002 and 2001, respectively, in other revenue.

On July 3, 2003, Quicksilver repurchased interests owned by the bank as a result of the Company's tax credit sales. Quicksilver paid $6.3 million to acquire all such interests in the Section 29 tax-eligible properties. As a result of the planned repurchase, the Company recorded, in the first quarter of 2003, a $0.5 million reduction of deferred revenue previously recognized.

13. COMMITMENTS AND CONTINGENCIES

The Company leases office buildings and other property under operating leases. Future minimum lease payments, in thousands, for operating leases with initial non-cancelable lease terms in excess of one year as of December 31, 2002, were as follows:

2004	$1,432
2005	1,430
2006	1,404
2007	1,014
2008	675
2009	675
Thereafter	208
Total lease commitments	$6,838

Rent expense for operating leases with terms exceeding one month was $1.4 million in 2003, $1.4 million in 2002 and $1.7 million in 2001.

As of December 31, 2003, the Company had approximately $1.6 million in letters of credit outstanding related to various state and federal bonding requirements.

Quicksilver has an incentive plan in place for three executives of MGV. The plan calls for a bonus to be payable as of December 31, 2005 (determination date) based principally on the value of proved reserves found and certain other measures. As of December 31, 2003 these performance measures had not been met and accordingly no accrual has been made. The Company will continue to evaluate the performance of the executives against the criteria set forth in the bonus plan and make accruals for such bonus payments when it determines that it is probable that the bonus payments will be made.

In August 2001, a group of royalty owners, Athel E. Williams et al., brought suit against the Company and three of its subsidiaries in the Circuit Court of Otsego County, Michigan. The suit alleges that Terra Energy Ltd, one of Quicksilver's subsidiaries, underpaid royalties or overriding royalties to the 13 named plaintiffs and to a class of plaintiffs who have yet to be determined. The pleadings of the plaintiffs seek damages in an unspecified amount and injunctive relief against future underpayments. The court heard arguments on class certification on November 8, 2002, and on December 6, 2002 the court issued a memorandum opinion granting class certification in part and denying it in part. The court stated that those portions of the royalty owners' complaint against Terra alleging that it deducted excessive postproduction costs from royalty payments should not be certified as class action. The court certified the remainder of the complaint for class action status. On December 20, 2002, the Company filed a motion for clarification and reconsideration of the court's order. That motion was denied on March 9, 2003. Based on information currently available to the Company, the Company's management believes that the final resolution of this matter will not have a material effect on its financial position, results of operations, or cash flows.

The Company is subject to various possible contingencies, which arise primarily from interpretation of federal and state laws and regulations affecting the natural gas and crude oil industry. Such contingencies include differing interpretations as to the prices at which natural gas and crude oil sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues and other matters. Although management believes it has complied with the various laws and regulations, administrative rulings and interpretations thereof, adjustments could be required as new interpretations and regulations are issued. In addition, production rates, marketing and environmental matters are subject to regulation by various federal and state agencies.

14. INCOME TAXES

Deferred income taxes are established for all temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. In addition, deferred tax balances must be adjusted to reflect tax rates that will be in effect in the years in which the temporary differences are expected to reverse. The Company has accrued no U.S. deferred income taxes on MGV's undistributed earnings or on the related translation adjustments pursuant to FAS No. 109, *Accounting for Income Taxes*, and APB No. 23, *Accounting for Income Taxes—Special Areas* as the Company expects MGV's undistributed earnings to be permanently reinvested for use in the development of its oil and gas reserves.

Significant components of the Company's deferred tax assets and liabilities as of December 31, 2003, 2002 and 2001 are as follows:

	2003	2002	2001
		(in thousands)	
Current			
Deferred tax asset			
Deferred tax benefit on cash flow hedge losses	$11,760	$ 9,045	$ 2,640
Non-current			
Deferred tax assets			
Deferred tax benefit on cash flow hedge losses	$ 3,022	$ 9,061	$ 4,612
Tax credit sale and unearned income	—	9,228	16,494
Net operating loss carry forwards	18,920	12,345	13,650
Other	166	123	355
Total deferred tax assets	22,108	30,757	35,111
Deferred tax liabilities			
Properties, plant, and equipment	92,818	87,822	88,864
Net deferred tax liabilities	$70,710	$57,065	$53,753

The provisions for income taxes for the years ended December 31, 2003, 2002 and 2001 are as follows:

	2003	2002	2001
		(in thousands)	
Current state income tax expense (benefit)	$ 79	$ (139)	$ 272
Current federal income tax expense (benefit)	—	(178)	178
Current foreign income tax expense	182	55	13
Total current income tax expense (benefit)	261	(262)	463
Deferred federal income tax expense	8,175	7,928	10,364
Deferred foreign income tax expense (benefit)	1,561	(168)	(27)
Total deferred income tax expense	9,736	7,760	10,337
Total	$9,997	$7,498	$10,800

A reconciliation of the statutory federal income tax rate and the effective tax rate for the years ended December 31, 2003, 2002 and 2001 are as follows:

	2003	2002	2001
U.S. federal statutory tax rate	35.00%	35.00%	35.00%
Change in net operating loss carry-forwards	—	—	—
Permanent differences	.18%	.86%	.33%
State income taxes net of federal deduction	.18%	(.42)%	.59%
Foreign income taxes	(.27)%	—	—
Other	(.02)%	(.29)%	(.05)%
Effective income tax rate	35.07%	35.15%	35.87%

Included in deferred tax assets are net operating losses of approximately $54.1 million that are available for carryover beginning in the year 2004 to reduce future U.S. taxable income. The net operating losses will expire in 2004 through 2023. These net operating losses have not been reduced by a valuation allowance, because management believes that future taxable income will more likely than not be sufficient to utilize substantially all of its tax carry forwards prior to their expirations. However, under Internal Revenue Code Section 382, a change of ownership was deemed to have occurred for our predecessor, MSR Exploration Ltd. ("MSR") in 1998. Due to the limitations imposed by Section 382, a portion of MSR's net operating losses could not be utilized and are not included in deferred tax assets.

15. EMPLOYEE BENEFITS

Quicksilver has a 401(k) retirement plan available to all employees with three months of service and who are at least 21 years of age. The Company may make discretionary contributions to the plan. Company contributions were $0.2 million for each of the years ended December 31, 2003, 2002 and 2001, respectively.

The Company initiated a self-funded health benefit plan effective July 1, 2001. The plan has been reinsured on an individual claim and total group claim basis. Quicksilver is responsible for payment of the first $50,000 for each individual claim. The claim liability for the total group was $1.3 million and $1.0 million for the plan years ended June 30, 2003 and 2002, respectively. Aggregate level reinsurance is in place for payment of claims up to $1 million over and above the estimated maximum claim liability of $1.7 million for the plan year ending June 30, 2004. Administrative expenses for the plan years ended June 30, 2003 and 2002 were $0.3 million and $0.4 million, respectively.

16. STOCKHOLDERS' EQUITY

The Company is authorized to issue 40 million shares of common stock with a par value per share of one cent ($0.01) and 10 million shares of preferred stock with a par value per share of one cent ($0.01). At December 31, 2003, the Company had 24,733,411 shares of common stock outstanding (including 170,421 shares issuable in respect to the MGV exchangeable shares and net of treasury shares) and one share of special voting preferred stock outstanding.

In connection with the December 2000 MGV minority interest acquisition, all issued and outstanding shares of MGV capital stock, other than those held by Quicksilver, were converted into 283,669 MGV exchangeable shares. Each MGV exchangeable share is a non-voting share of MGV's capital stock exchangeable for one share of Quicksilver common stock. Exchange can occur as a result of (i) liquidation of MGV; (ii) exercise of a redemption right by an MGV shareholder requiring MGV to purchase exchangeable shares; or (iii) exercise of an exchange put right by an MGV shareholder requiring Quicksilver to exchange the exchangeable shares for

Quicksilver common stock. Any MGV exchangeable shares still outstanding on December 31, 2005 will be treated as having been the subject of an exercise of an exchange put right on that date. Upon exchange, the holder of exchangeable shares is entitled to receive one share of Quicksilver common stock and the full amount of all cash dividends declared on a share of Quicksilver common stock from the date of issuance of the exchangeable share to the date of exchange. In order to provide voting rights to holders of MGV exchangeable shares equivalent to the voting rights of the Quicksilver common shares, Quicksilver created, on December 15, 2000, a series of its preferred stock designated as Special Voting Stock. Quicksilver issued a single share of Special Voting Stock to an appointee. During 2002, 10,000 exchangeable shares of MGV were presented to Quicksilver for purchase for $189,100. A total of 57,000, 42,748 and 3,500 MGV exchangeable shares were converted to Quicksilver common stock during 2003, 2002 and 2001, respectively.

The following table shows common share and treasury share activity since January 1, 2001:

	Common Shares Issued	Treasury Shares Held
Opening Balance January 1, 2001	22,332,950	3,765,947
Stock options exercised	85,425	1,000
Warrants exercised	120,000	—
Treasury stock issue	—	(15,095)
MGV Class C Retraction	(3,500)	—
Balance at December 31, 2001	22,534,875	3,751,852
Treasury stock issued to executives	—	(37,100)
Stock options exercised	152,822	—
Warrants exercised	985,750	—
MGV Class C Retraction	(10,000)	—
Treasury stock purchased	—	5,750
Treasury stock issued	—	(1,150,000)
Balance at December 31, 2002	23,663,447	2,570,502
Stock options exercised	148,868	8,402
Stock issuance	3,500,000	—
Balance at December 31, 2003	27,312,315	2,578,904

The Company's restated certificate of incorporation authorizes its board of directors to issue preferred stock without stockholder approval. If the Company's board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire control of the Company, even if that change of control might be beneficial to stockholders. The Company's restated certificate also provides for a classified board of directors. This staggered election approach makes more difficult and discourages a proxy contest or the assumption of control by a substantial stockholder and thus increases the likelihood that incumbent directors will retain their positions. In March 2003, by amendment of its bylaws, the Company established an advance notice requirement for director nominations by stockholders and actions to be taken at annual meetings and a stockholders' rights plan. These bylaw amendments and the stockholder rights plan could impede a merger, consolidation, takeover or other business combination involving the Company or discourage a potential acquirer from making a tender offer or otherwise attempting to take control of the Company. In certain circumstances, the fact that corporate devices are in place that will inhibit or discourage takeover attempts could reduce the market value of the Company's common stock.

Stockholder Rights Plan

On March 11, 2003, the Company's board of directors declared a dividend distribution of one preferred share purchase right for each outstanding share of common stock of the Company outstanding on March 26, 2003. Each right, when it becomes exercisable, entitles stockholders to buy one one-thousandth of a share of the Company's Series A Junior Participating Preferred Stock at an exercise price of $100.00.

The rights will be exercisable only if such a person or group acquires 15 percent or more of the common stock of Quicksilver or announces a tender offer the consummation of which would result in ownership by such a person or group (an "Acquiring Person") of 15 percent or more of the common stock of the Company. Such 15 percent threshold does not apply to certain members of the Darden family who collectively owned, directly or indirectly, approximately 38% of the Company's common stock at December 31, 2003.

If Quicksilver is acquired in a merger or other business combination transaction after an Acquiring Person has acquired 15 percent or more of the outstanding common stock of the Company, each right will entitle its holder to purchase, at the right's then-current exercise price, a number of the acquiring company's common shares having a market value of twice such price. In addition, if an Acquiring Person acquires 15 percent or more of the outstanding common stock of the Company, each right will entitle its holder to purchase, at the right's then-current exercise price, a number of common shares of the Company having a market value of twice such price.

Prior to the acquisition by an Acquiring Person of beneficial ownership of 15 percent or more of the common stock of Quicksilver, the rights are redeemable for one cent per right at the option of the board of directors of the Company.

Stock Option Plan

On October 4, 1999, the Board of Directors adopted the Company's 1999 Stock Option and Retention Stock Plan (the "1999 Plan"), which was approved at the annual stockholders' meeting held in June 2000. There are 2.5 million shares of common stock reserved under the 1999 Plan, which provides for the grant of incentive stock options, non-qualified stock options, stock appreciation rights and retention stock awards. In December of 2003, the Company's Board of Directors approved an increase for the number of shares reserved for issuance under the 1999 Plan from 1.3 million shares to 2.5 million shares. Such increase is subject to stockholder approval at the Company's May 18, 2004 annual meeting of stockholders.

Under terms of the 1999 Plan, options may be granted to officers and employees at an exercise price that is not less than 100% of the fair market value on the date of grant, and which are exercisable in whole or part by the optionee after at least one year of continuous service from the date of grant. Incentive stock options and non-qualified options may not be exercised more than ten years from date of grant. A summary of stock option transactions under the 1999 Plan is as follows:

	2003		2002		2001	
	Shares	Wtd Avg Exercise Price	Shares	Wtd Avg Exercise Price	Shares	Wtd Avg Exercise Price
Outstanding at beginning of year	738,211	$ 7.50	846,087	$ 5.88	802,059	$ 4.78
Granted	52,094	22.90	69,253	17.03	132,153	13.03
Exercised	(148,868)	6.32	(168,847)	4.85	(85,425)	4.62
Cancelled	—	—	(6,282)	7.13	—	—
Forfeited	(12,081)	16.93	(2,000)	17.02	(2,700)	8.75
Outstanding at end of year	629,356	$ 8.90	738,211	$ 7.50	846,087	$ 6.58
Exercisable at end of year	456,924	$ 7.65	385,157	$ 6.65	196,499	$ 5.88
Weighted average fair value of options granted		$12.36		$ 7.39		$ 6.77

Pro forma information regarding net income and earnings per share is required by SFAS No. 123, and has been determined as if the Company had accounted for its employee stock options under the fair value method of that statement. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions:

	2003	2002	2001
Wtd avg grant date	Feb 21, 2003	Feb 5, 2002	Jul 28, 2001
Risk-free interest rate	2.8%	3.0%	3.5%
Expected life (in years)	6.0	3.5	3.5
Expected volatility	54.9%	55.6%	60.7%
Dividend yield	—	—	—

The following table summarizes information about stock options outstanding at December 31, 2003.

	Options Outstanding			Options Exercisable	
Range of Exercisable Prices	At 12/31/03	Wtd Avg Remaining Contractual Life	Wtd Avg Exercise Price	At 12/31/03	Wtd Avg Exercise Price
$ 3-4	235,933	1.1	$ 3.69	235,933	$ 3.69
7-8	208,333	1.5	7.13	100,000	7.13
9-10	33,352	2.1	9.80	33,352	9.80
16-18	101,908	3.0	16.51	70,797	16.69
22-25	49,830	4.1	22.86	16,842	24.10
	629,356	1.8	$ 8.89	456,924	$ 7.65

17. OTHER REVENUE

Other revenue consists of the following:

	For the Years Ended December 31,		
	2003	2002	2001
	(in thousands)		
Section 29 tax credit sales	$ (582)	$5,129	$10,895
Marketing	1,208	3,021	3,623
Processing and transportation	1,286	1,533	1,520
Other	—	—	580
	$1,912	$9,683	$16,618

18. SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid for interest and income taxes is as follows:

	For the Years Ended December 31,		
	2003	2002	2001
	(in thousands)		
Interest	$19,543	$19,730	$22,877
Income taxes	66	147	303

Other non-cash transactions are as follows:

	For the Years Ended December 31,		
	2003	2002	2001
	(in thousands)		
Distribution of equity to Mercury Exploration Company	$(515)	$—	$—
Deferred tax benefit recognized on exercise of employee stock option exercises	739	—	—
Treasury stock (acquired) reissued:			
8,402 shares for exercise of employee stock options	(200)	—	—
37,100 shares for payment of executives' compensation	—	364	—
15,095 shares for payment of directors' compensation	—	—	100

19. RELATED PARTY TRANSACTIONS

As of December 31, 2003, the Darden family has approximately 38% beneficial ownership in Quicksilver including shares owned directly, and shares owned by Mercury Exploration Company and Quicksilver Energy L.P., companies that are owned by the Dardens. Thomas Darden, Glenn Darden and Anne Darden Self are officers and directors of the Company.

During 2002, Quicksilver paid $0.85 million and $0.90 million, respectively, for principal and interest on the note payable to Mercury associated with the 2000 acquisition of assets from Mercury. During 2003, Quicksilver paid Mercury $2.05 million principal and interest to retire the note. Quicksilver and its associated entities paid $0.78 million, $0.74 million and $0.73 million for rent in 2003, 2002 and 2001, respectively, on buildings which are owned by a Mercury affiliate. Rental rates were determined based on comparable rates charged by third parties.

Effective July 1, 2000, Quicksilver purchased the natural gas producing, gathering, transmission and marketing assets of, and 65% of Voyager Compression Services, LLC ("Voyager"), a gas compression company, from Mercury for $18 million. An independent appraiser determined the fairness, from a financial point of view, of the $18 million purchase price and the disinterested members of the Board of Directors approved the purchase. Mercury continues to own 33% of Voyager, and Jeff Cook, an officer of the Company, owns 2%.

Quicksilver accounted for its 65% holdings in Voyager under the equity method since control over Voyager was shared equally with Mercury.

During 2002, Quicksilver purchased compressors and equipment for $3.7 million and maintenance and related services for $1.8 million from Voyager at terms as favorable as those granted by Voyager to third parties. Also in 2002, Voyager recognized an impairment loss of $0.9 million related to its inventory, fixed assets and operating leases for facilities. Subsequently, Voyager sold, to a third party, its Michigan inventory and fixed assets and recognized a gain on the sale of $0.2 million. Quicksilver recognized its proportionate share of these items during 2002.

Voyager sold its compressor service fixed assets and the majority of its Texas inventory to Quicksilver for $1.6 million (its historical cost that approximated fair value) in February 2003. In addition, Quicksilver paid Voyager $2.2 million for the fair value of its compressor service contracts. After completion of the sale of the service contracts and other assets, Quicksilver received a $0.2 million cash distribution from Voyager and recorded a $0.5 million equity distribution to Mercury for its share of Voyager's gain from the disposition of the Compressor service contracts to Quicksilver. The transaction was reviewed and approved by the disinterested members of the Board of Directors. Mercury's portion of the gain on the sale of the service contracts was treated as an equity distribution by Quicksilver as Mercury and the Darden family are considered as having a controlling interest in Quicksilver. Quicksilver's gain on the sale of the contracts was eliminated.

During 2003, Voyager also sold, to a Mercury affiliate, leasehold improvements on operating leases with that Mercury affiliate at historical cost, which approximates fair value, of approximately $0.8 million. The leases were cancelled, and Voyager's lease cancellation costs were $0.4 million.

20. SEGMENT INFORMATION

The Company operates in two geographic segments, the United States and Canada. Both areas are engaged in the exploration and production segment of the oil and gas industry. The Company evaluates performance based on operating income.

	United States	Canada	Corporate	Consolidated
2003				
Revenues	$129,235	$ 11,714	$ —	$140,949
Depletion, depreciation and accretion	29,036	2,562	469	32,067
Operating income	51,898	5,202	(8,602)	48,498
Fixed assets—net	496,102	106,789	1,685	604,576
Expenditures for assets	78,936	69,297	255	148,488
2002				
Revenues	$119,917	$ 2,062	$ —	$121,979
Depletion, depreciation and accretion	28,932	675	552	30,159
Operating income (loss)	49,143	(337)	(8,104)	40,702
Fixed assets—net	436,195	31,984	1,899	470,078
Expenditures for assets	73,480	15,161	324	88,965
2001				
Revenues	$139,694	$ 2,269	$ —	$141,963
Depletion, depreciation and accretion	27,659	566	418	28,643
Operating income (loss)	61,530	(35)	(8,088)	53,407
Fixed assets—net	392,988	17,340	2,127	412,455
Expenditures for assets	55,709	10,964	736	67,409

21. SUPPLEMENTAL INFORMATION (UNAUDITED)

Proved oil and gas reserves estimates were prepared by independent petroleum engineers with Schlumberger Data and Consulting Services and Netherland, Sewell & Associates, Inc. The reserve reports were prepared in accordance with guidelines established by the Securities and Exchange Commission and, accordingly, were based on existing economic and operating conditions. Natural gas and crude oil prices in effect as of the date of the reserve reports were used without any escalation except in those instances where the sale of production was covered by contract, in which case the applicable contract prices, including fixed and determinable escalations, were used for the duration of the contract, and thereafter the year-end price was used (See "Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves" below for a discussion of the effect of the different prices on reserve quantities and values.) Operating costs, production and ad valorem taxes and future development costs were based on current costs with no escalation.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. Moreover, the present values should not be construed as the current market value of the Company's natural gas and crude oil reserves or the costs that would be incurred to obtain equivalent reserves.

The changes in proved reserves for the years ended December 31, 2001, 2002 and 2003 were as follows:

	Natural Gas (MMcf)			Crude Oil (MBbl)			NGL (MBbl)		
	United States	Canada	Total	United States	Canada	Total	United States	Canada	Total
December 31, 2000	554,647	16,167	570,814	14,850	6	14,856	1,535	—	1,535
Revisions	(43,371)	20	(43,351)	(449)	(6)	(455)	194	3	197
Extensions and discoveries	53,655	1,200	54,855	—	—	—	—	—	—
Purchases in place	1,893	—	1,893	2	—	2	1	—	1
Production	(31,815)	(874)	(32,689)	(1,059)	—	(1,059)	(192)	(3)	(195)
December 31, 2001	535,009	16,513	551,522	13,344	—	13,344	1,538	—	1,538
Revisions	40,288	1,375	41,663	2,153	—	2,153	214	—	214
Extensions and discoveries	30,330	36,649	66,979	1,444	—	1,444	619	—	619
Purchases in place	64,267	—	64,267	25	—	25	1	—	1
Sales in place	—	—	—	(59)	—	(59)	—	—	—
Production	(31,910)	(935)	(32,845)	(905)	—	(905)	(156)	—	(156)
December 31, 2002	637,984	53,602	691,586	16,002	—	16,002	2,216	—	2,216
Revisions	(9,137)	2,363	(6,774)	(2,022)	1	(2,021)	(165)	2	(163)
Extensions and discoveries	45,081	93,591	138,672	—	—	—	—	—	—
Purchases in place	1,204	—	1,204	—	—	—	—	—	—
Production	(31,612)	(2,924)	(34,536)	(807)	(1)	(808)	(133)	(2)	(135)
December 31, 2003	643,520	146,632	790,152	13,173	—	13,173	1,918	—	1,918
Proved developed reserves									
December 31, 2001	456,074	8,890	464,964	8,543	—	8,543	1,023	—	1,023
December 31, 2002	550,889	22,750	573,639	10,722	—	10,722	1,524	—	1,524
December 31, 2003	569,978	83,698	653,676	8,734	—	8,734	1,405	—	1,405

The capitalized costs relating to oil and gas producing activities and the related accumulated depletion, depreciation and accretion as of December 31, 2003, 2002 and 2001 were as follows:

	United States	Canada	Consolidated
		(in thousands)	
2003			
Proved properties	$ 577,322	$ 88,135	$ 665,457
Unevaluated properties	27,110	22,809	49,919
Accumulated DD&A	(155,183)	(4,618)	(159,801)
Net capitalized costs	$ 449,249	$106,326	$ 555,575
2002			
Proved properties	$ 524,947	$ 20,431	$ 545,378
Unevaluated properties	3,888	13,025	16,913
Accumulated DD&A	(129,194)	(1,712)	(130,906)
Net capitalized costs	$ 399,641	$ 31,744	$ 431,385
2001			
Proved properties	$ 472,902	$ 8,023	$ 480,925
Unevaluated properties	4,221	10,237	14,458
Accumulated DD&A	(113,333)	(1,103)	(114,436)
Net capitalized costs	$ 363,790	$ 17,157	$ 380,947

Costs incurred in oil and gas property acquisition, exploration and development activities during the years ended December 31, 2003, 2002 and 2001 were as follows:

	United States	Canada	Consolidated
		(in thousands)	
2003			
Proved acreage	$ 3,215	$ 3,388	$ 6,603
Unproved acreage	24,063	6,739	30,802
Development costs	47,480	43,001	90,481
Exploration costs	9,411	17,066	26,477
Total	$ 84,169	$ 70,194	$154,363
2002			
Proved acreage	$ 32,199	$ —	$ 32,199
Unproved acreage	550	5,422	5,972
Development costs	34,178	938	35,116
Exploration costs	5,925	8,659	14,584
Total	$ 72,852	$ 15,019	$ 87,871
2001			
Proved acreage	$ 2,811	$ 343	$ 3,154
Unproved acreage	2,595	197	2,792
Development costs	47,776	2,229	50,005
Exploration costs	2,081	8,022	10,103
Total	$ 55,263	$ 10,791	$ 66,054

Results of operations from producing activities for the years ended December 31, 2003, 2002 and 2001 are set forth below:

	United States	Canada	Consolidated
		(in thousands)	
2003			
Natural gas, crude oil & NGL sales	$127,339	$11,698	$139,037
Oil & gas production expense	48,243	3,951	52,194
Depletion expense	25,600	2,428	28,028
	53,496	5,319	58,815
Income tax expense	18,724	2,107	20,831
Results from producing activities	$ 34,772	$ 3,212	$ 37,984
2002			
Natural gas, crude oil & NGL sales	$110,291	$ 2,005	$112,296
Oil & gas production expense	40,505	1,723	42,228
Depletion expense	26,352	601	26,953
	43,434	(319)	43,115
Income tax expense	15,199	(138)	15,061
Results from producing activities	$ 28,235	$ (181)	$ 28,054
2001			
Natural gas, crude oil & NGL sales	$123,077	$ 2,268	$125,345
Oil & gas production expense	50,967	1,738	52,705
Depletion expense	25,647	515	26,162
	46,463	15	46,478
Income tax expense	16,260	6	16,266
Results from producing activities	$ 30,203	$ 9	$ 30,212

The Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves ("Standardized Measure") does not purport to present the fair market value of the Company's natural gas and crude oil properties. An estimate of such value should consider, among other factors, anticipated future prices of natural gas and crude oil, the probability of recoveries in excess of existing proved reserves, the value of probable reserves and acreage prospects, and perhaps different discount rates. It should be noted that estimates of reserve quantities, especially from new discoveries, are inherently imprecise and subject to substantial revision.

Under the Standardized Measure, future cash inflows were estimated by applying year-end prices, adjusted for contracts with price floors but excluding hedges, to the estimated future production of the year-end reserves. These prices have varied widely and have a significant impact on both the quantities and value of the proved reserves as reduced prices cause wells to reach the end of their economic life much sooner and also make certain proved undeveloped locations uneconomical, both of which reduce reserves. The following representative natural gas and crude oil year-end prices were used in the Standardized Measure. These prices were adjusted by field for appropriate regional differentials.

	At December 31,		
	2003	2002	2001
Natural gas (NYMEX Henry Hub)	$ 5.97	$ 4.74	$ 2.57
Crude oil (NYMEX)	32.55	31.20	19.84

Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future income taxes were computed by applying the statutory tax rate to the excess of pre-tax cash inflows over the Company's tax basis in the associated proved natural gas and crude oil properties. Tax credits and net operating loss carry forwards were also considered in the future income tax calculation. Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the Standardized Measure.

The standardized measure of discounted cash flows related to proved oil and gas reserves at December 31, 2003, 2002 and 2001 were as follows:

	United States	Canada	Consolidated
		(in thousands)	
2003			
Future revenues	$ 4,125,685	$ 746,722	$ 4,872,407
Future production costs	(1,368,849)	(126,070)	(1,494,919)
Future development costs	(90,648)	(56,790)	(147,438)
Future income taxes	(851,337)	(162,636)	(1,013,973)
Future net cash flows	1,814,851	401,226	2,216,077
10% discount—calculated difference	(1,120,056)	(247,280)	(1,367,336)
Standardized measure of discounted future net cash flows relating to proved reserves	$ 694,795	$ 153,946	$ 848,741
2002			
Future revenues	$ 3,354,927	$ 206,602	$ 3,561,529
Future production costs	(1,260,500)	(40,504)	(1,301,004)
Future development costs	(96,748)	(14,373)	(111,121)
Future income taxes	(616,865)	(52,680)	(669,545)
Future net cash flows	1,380,814	99,045	1,479,859
10% discount—calculated difference	(802,968)	(62,040)	(865,008)
Standardized measure of discounted future net cash flows relating to proved reserves	$ 577,846	$ 37,005	$ 614,851
2001			
Future revenues	$ 1,671,787	$ 34,513	$ 1,706,300
Future production costs	(836,257)	(10,209)	(846,466)
Future development costs	(76,709)	(2,716)	(79,425)
Future income taxes	(190,278)	(5,413)	(195,691)
Future net cash flows	568,543	16,175	584,718
10% discount—calculated difference	(306,225)	(9,551)	(315,776)
Standardized measure of discounted future net cash flows relating to proved reserves	$ 262,318	$ 6,624	$ 268,942

The primary changes in the standardized measure of discounted future net cash flows for the years ended December 31, 2003, 2002 and 2001 were as follows:

	As of December 31,		
	2003	2002	2001
		(in thousands)	
Net changes in price and production costs	$130,534	$ 358,878	$(1,289,950)
Development costs incurred	44,167	35,116	50,202
Revision of estimates	(27,901)	63,866	(11,390)
Changes in estimated future development costs	(12,703)	(63,980)	(44,978)
Purchase and sale of reserves, net	1,832	63,539	2,015
Extensions and discoveries	170,660	87,555	16,699
Net change in income taxes	(99,013)	(162,889)	433,461
Sales of oil and gas net of production costs	(86,843)	(70,068)	(72,640)
Accretion of discount	86,775	35,895	159,928
Other	26,382	(2,003)	(43,697)
Net increase (decrease)	$233,890	$ 345,909	$ (800,350)

22. SELECTED QUARTERLY DATA (UNAUDITED)

	Mar 31	Jun 30	Sep 30	Dec 31
2003	(In thousands, except per share data)			
Operating revenues	$37,516	$33,095	$33,513	$36,825
Operating income	14,915	10,102	11,643	11,838
Income before effect of accounting change	6,412	1,109	5,229	5,755
Net income	4,115	1,109	5,229	5,755
Basic income per share before effect of accounting change	$ 0.30	$ 0.05	$ 0.23	$ 0.23
Basic net income per share	0.19	0.05	0.23	0.23
Diluted income per share before effect of accounting change	0.30	0.05	0.23	0.23
Diluted net income per share	0.19	0.05	0.23	0.23
2002				
Operating revenues	$28,899	$31,000	$30,307	$31,773
Operating income	8,177	10,283	11,045	11,197
Net income	2,172	3,690	3,640	4,333
Basic net income per share	$ 0.11	$ 0.19	$ 0.18	$ 0.21
Diluted net income per share	0.11	0.18	0.18	0.21

ITEM 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

ITEM 9A. Controls and Procedures

Management, including our president and chief executive officer and senior vice president and chief financial officer, evaluated effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2003. Based upon, and as of the date of, that evaluation, the president and chief executive officer and senior vice president and chief financial officer concluded that the disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported as and when required.

There has not been any change in our internal control over financial reporting during our most recently completed fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART III

ITEM 10. Directors and Executive Officers of the Registrant

The information concerning our directors is set forth under "Item 1—Election of Directors" in the proxy statement for our May 18, 2004 annual meeting of stockholders is incorporated herein by reference. The information concerning any changes to the procedure by which security holder may recommend nominees to the board of directors is set forth under "Stockholder Nominations of Directors" in the proxy statement for our May 18, 2004 meeting of stockholders is incorporated herein by reference. Certain information concerning our executive officers is set forth under the heading "Business—Executive Officers" in Item 1 of this Annual Report. The information concerning compliance with Section 16(a) of the Exchange Act is set forth under "Section 16(a) Beneficial Ownership Reporting Compliance" in the proxy statement for our May 18, 2004 annual meeting of stockholders is incorporated herein by reference.

The information concerning our audit committee is set forth under "Committees of the Board of Directors" in the proxy statement for our May 18, 2004 annual meeting of stockholders is incorporated herein by reference.

The information regarding our Code of Ethics is set forth under "Code of Business Conduct and Ethics" in the proxy statement for our May 18, 2004 annual meeting of stockholders is incorporated herein by reference.

ITEM 11. Executive Compensation

The information set forth under "Executive Compensation" in our proxy statement for our May 18, 2004 annual meeting of stockholders is incorporated herein by reference.

ITEM 12. Security Ownership of Management and Certain Beneficial Owners

The information set forth under "Security Ownership of Management and Certain Beneficial Holders" in the proxy statement for our May 18, 2004 annual meeting of stockholders is incorporated herein by reference. The information regarding our equity plans under which shares of our common stock are authorized for issuance as set forth under "Security Ownership of Management and Certain Beneficial Holders" in the proxy statement of our May 18, 2004 annual meeting of stockholders is incorporated herein by reference.

ITEM 13. Certain Relationships and Related Transactions

The information set forth under "Transactions with Management and Certain Stockholders" in the proxy statement for our May 18, 2004 annual meeting of stockholders is incorporated herein by reference.

ITEM 14. Principal Accountant Fees and Services.

The information set forth under "Independent Public Accountants" in the proxy statement for our May 18, 2004 annual meeting of stockholders is incorporated herein by reference.

PART IV

ITEM 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

(a) The following documents are filed as part of this report:

1. Financial Statements:

   The following financial statements of ours and the report of our Independent Auditors thereon are included on pages 47 through 84 of this Form 10-K.

   Independent Auditors' Report

   Consolidated Balance Sheets as of December 31, 2003 and 2002

   Consolidated Statements of Income for the years ended December 31, 2003, 2002 and 2001

   Consolidated Statements of Stockholders' Equity and Comprehensive Income for the years ended December 31, 2003, 2002 and 2001

   Consolidated Statements of Cash Flows for the years ended December 31, 2003, 2002 and 2001

   Notes to Consolidated Financial Statements for the Years Ended December 31, 2003, 2002 and 2001

2. Financial Statement Schedules:

   All schedules are omitted because the required information is inapplicable or the information is presented in the financial statements or the notes thereto.

(b) Reports on Form 8-K:

Current Report on Form 8-K dated October 3, 2003 and furnished to the SEC on October 6, 2003, reporting under Items 7 and 12 a press release announcing an operations update with production and earnings guidance.

Current Report on Form 8-K dated and furnished to the SEC on November 10, 2003, reporting under Items 7 and 12 a press release announcing third quarter operating results.

Current Report on Form 8-K dated and furnished to the SEC on February 13, 2004, reporting under Item 5: effective as of December 31, 2003, Quicksilver Energy, L.C., a principal stockholder of ours, was merged into Quicksilver Energy, L.P. Each of Mercury Exploration Company, Thomas F. Darden, Glenn Darden and Anne Darden Self were members of Quicksilver Energy, L.C. and, as such, shared voting and investment power with respect to 3,030,861 shares of our common stock beneficially owned by Quicksilver Energy, L.C. The general partner of Quicksilver Energy, L.P. is Pennsylvania Management, LLC, an entity controlled by the Darden family. Mercury and the Dardens are limited partners of Quicksilver Energy, L.P.

Current Report on Form 8-K dated and furnished to the SEC on February 24, 2004, reporting under Items 7 and 12 a press release announcing 2003 proved reserve additions.

Current Report on Form 8-K dated and furnished to the SEC on March 4, 2004, reporting under Items 7 and 12 a press release announcing fourth quarter and full year operating results.

(c) Exhibits:

Exhibit No.	Sequential Description
3.1	Restated Certificate of Incorporation of Quicksilver Resources Inc. (filed as Exhibit 4.1 to the Company's Form S-4 File No. 333-66709, filed November 3, 1998 and included herein by reference).
3.2	Certificate of Designation, Preferences and Rights of Preferred Stock (filed as Exhibit 3.2 to the Company's Form 10-K filed March 27, 2001 and included herein by reference).

Exhibit No.	Sequential Description
3.3	Certificate of Amendment to the Restated Certificate of Incorporation of Quicksilver Resources Inc. (filed as Exhibit 3.1 to the Company's Form 10-Q filed August 14, 2001 and included herein by reference).
3.4	Certificate of Designation of Series A Junior Participating Preferred Stock of Quicksilver Resources Inc. (filed as Exhibit 3.4 to the Company's Form 10-K filed March 26, 2003 and included herein by reference).
3.5	Bylaws of Quicksilver Resources Inc. (filed as Exhibit 4.2 to the Company's Form S-4 File No. 333-66709, filed November 3, 1998 and included herein by reference).
3.6	Amendment to the Bylaws of Quicksilver Resources Inc. adopted on November 30, 1999 (filed as Exhibit 3.4 to the Company's Form 10-K filed March 27, 2001 and included herein by reference).
3.7	Amendment to the Bylaws of Quicksilver Resources Inc., adopted June 5, 2001 (filed as Exhibit 3.2 to the Company's Form 10-Q filed August 14, 2001 and included herein by reference).
3.8	Amendment to the Bylaws of Quicksilver Resources Inc., adopted March 11, 2003 (filed as Exhibit 3.8 to the Company's Form 10-K filed March 26, 2003 and included herein by reference).
4.1	Rights Agreement, dated as of March 11, 2003, between Quicksilver Resources Inc. and Mellon Investor Services LLC, as Rights Agent (filed as Exhibit 4.1 to the Company's Form 8-A filed March 14, 2003 and included herein by reference).
4.2	Note Purchase Agreement, dated June 27, 2003, between the Company and the Purchasers identified therein (filed as Exhibit 4.2 to the Company's Form 10-Q filed August 14, 2003 and included herein by reference).
10.1	Master Gas Purchase and Sale Agreement dated March 1, 1999, by and between Quicksilver Resources Inc. and Reliant Energy Services, Inc. (filed as Exhibit 10.10 to the Company's Form S-1 File No. 333-89229, filed October 18, 1999 and included herein by reference).
10.2	Wells Agreement dated as of December 15, 1970, between Union Oil Company of California and Montana Power Company (filed as Exhibit 10.5 to the Company's Predecessor, MSR Exploration Ltd.'s Registration Statement on Form S-4/A File No. 333-29769, filed on August 21, 1997 and included herein by reference).
+10.3	Quicksilver Resources Inc. 1999 Stock Option and Retention Stock Plan (filed as Exhibit 10.28 to the Company's Form S-1 File No. 333-89229, filed October 18, 1999 and included herein by reference).
10.4	Fourth Amended and Restated Credit Agreement, dated as of May 13, 2002, among Quicksilver Resources Inc., as Borrower, Bank of America, N.A., as Administrative Agent, and the financial institutions listed therein (filed as Exhibit 10.6 to the Company's Form 10-Q filed May 15, 2002 and included herein by reference).
10.5	First Amendment to Fourth Amended and Restated Credit Agreement, dated as of September 25, 2002, among Quicksilver Resources Inc., as Borrower, Bank of America, N.A., as Administrative Agent, and the financial institutions listed therein (filed as Exhibit 10.5 to the Company's Form 10-Q filed August 14, 2003 and included herein by reference).
10.6	Second Amendment to Fourth Amended and Restated Credit Agreement, dated as of June 27, 2003, among Quicksilver Resources Inc., as Borrower, Bank of America, N.A., as Administrative Agent, and the financial institutions listed therein (filed as Exhibit 10.6 to the Company's Form 10-Q filed August 14, 2003 and included herein by reference).
*21.1	List of subsidiaries of Quicksilver Resources Inc.
*23.1	Consent of Deloitte & Touche LLP.
*23.2	Consent of Schlumberger Data and Consulting Services.

Exhibit No.	Sequential Description
*23.3	Consent of Netherland, Sewell & Associates, Inc.
*31.1	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

\+ Identifies management contracts and compensatory plans or arrangements.

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.

QUICKSILVER RESOURCES INC.
(the "Registrant")

by: /s/ GLENN DARDEN
Glenn Darden
President and Chief Executive Officer

Dated: March 15, 2004

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

SIGNATURE	TITLE	DATE
/s/ THOMAS F. DARDEN **Thomas F. Darden**	Chairman of the Board and Director	March 15, 2004
/s/ GLENN DARDEN **Glenn Darden**	President, Chief Executive Officer and Director	March 15, 2004
/s/ BILL LAMKIN **Bill Lamkin**	Executive Vice President and Chief Financial Officer	March 15, 2004
/s/ D. WAYNE BLAIR **D. Wayne Blair**	Vice President and Controller	March 15, 2004
/s/ ANNE DARDEN SELF **Anne Darden Self**	Vice President—Human Resources And Director	March 15, 2004
James A. Hughes	Director	March 15, 2004
/s/ D. RANDALL KENT **D. Randall Kent**	Director	March 15, 2004
/s/ STEVEN M. MORRIS **Steven M. Morris**	Director	March 15, 2004
/s/ W. YANDELL ROGERS, III **W. Yandell Rogers, III**	Director	March 15, 2004
/s/ MARK J. WARNER **Mark J. Warner**	Director	March 15, 2004

CORPORATE INFORMATION

Directors

Thomas F. Darden, Chairman

Glenn Darden

D. Randall Kent

Steven M. Morris

W. Yandell Rogers III

Anne D. Self

Mark Warner

Officers

Thomas F. Darden
Chairman

Glenn Darden
President & Chief Executive Officer

Bill M. Lamkin
Executive Vice President &
Chief Financial Officer

Jeff Cook
Senior Vice President - Operations

Mark D. Whitley
Vice President - Operations

John C. Cirone
Vice President - General Counsel & Secretary

Robert N. Wagner
Vice President - Reserves Group

Anne D. Self
Vice President - Human Resources

D. Wayne Blair
Vice President - Controller

MarLu Hiller
Treasurer

Headquarters

777 West Rosedale Street, Suite 300
Fort Worth, Texas 76104
Phone:(817) 665-5000 Fax: (817) 665-5004
Email: quicksilver@qrinc.com
Web Site: www.qrinc.com

Stock Exchange Listing

New York Stock Exchange
Trading Symbol: KWK

Major Subsidiaries

MGV Energy Inc.
One Palliser Square
2000, 125-9th Avenue, SE
Calgary, Alberta Canada T2G OP8
Phone:(403) 537-2455 Fax: (403) 262-6115

J. Michael Gatens
Chairman of the Board & Chief Executive Officer

George W. Voneiff
President & Chief Operating Officer

Registrar and Transfer Agent

Mellon Investor Services
Stock Transfer Department
85 Challenger Road, Overpeak Centre
Ridgefield Park, New Jersey 07660
(800) 635-9270
Web Site: www.melloninvestor.com

Auditors

Deloitte & Touche LLP
301 Commerce Street, Suite 2950
Fort Worth, Texas 76102

Legal Counsel

Cantey & Hanger, LLP
801 Cherry Street, Suite 2100
Fort Worth, Texas 76102

Investor Relations

Diane K. Weaver
Director of Investor Relations
Phone:(817) 665-4834
Email: dweaver@qrinc.com

Annual Meeting

The Company's Annual Meeting of Shareholders is scheduled for 9:00 a.m., May 18, 2004 at the Fort Worth Club, 306 W. 7th Street, Fort Worth, Texas.

QUICKSILVER
RESOURCES
777 West Rosedale Street
Fort Worth, Texas 76104
(817) 665-5000
NYSE:KWK