EQUITY OIL CO
Form 10-K
March 20, 2003

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2002

OR

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

Commission file number 0-610

EQUITY OIL COMPANY

[Exact name of registrant as specified in its charter]

Colorado (State or other jurisdiction of incorporation or organization)	**87-0129795** (I.R.S. Employer Identification Number)
10 West Broadway, Suite 806 **Salt Lake City, Utah** (Address of principal executive offices)	**84101** (Zip Code)

Registrant's telephone number, including area code: **(801) 521-3515**

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

Title of each class	Name of each exchange on which registered
None	**None**

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

Common Stock (par value, $1 per share)
[Title of class]

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 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 ý No o

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

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

As of March 11, 2003, 12,008,661 common shares were outstanding, and the aggregate market value of voting stock held by non-affiliates of the registrant, based upon the closing price of such stock on June 28, 2002, was approximately $26,400,000.

Documents Incorporated by Reference

Portions of the definitive proxy statement for the Registrant's 2003 Annual Meeting of Stockholders to be held on May 21, 2003 are incorporated by reference in Part III of this Form 10-K. Such definitive proxy statement will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2002.

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ITEM

PART I

ITEM 1. BUSINESS

General

Equity Oil Company, or Equity, is an independent energy company engaged in oil and natural gas exploration, production and acquisition activities. References in this report to "Equity", "we", "our", or "us" refer to Equity Oil Company. Equity was originally incorporated in the state of Utah in 1923. In 1958, we merged into our subsidiary, Weber Oil Company, a Colorado corporation. The surviving company adopted the name Equity Oil Company.

We currently conduct business in seven states and two Canadian provinces. Headquartered in Salt Lake City, Utah, we maintain a technical office in Denver, Colorado, and an operations office in Cody, Wyoming. Currently, we have 28 full-time employees.

Our operations are focused in the following three core areas:

- the Rocky Mountains,
- Northern California's Sacramento Basin, and
- the Cessford area in Alberta Canada.

Our executive office in Salt Lake City is responsible for conducting all administrative functions, including strategic planning, direction of exploration and development activities, shareholder relations, and financial and legal services.

Our technical office in Denver is responsible for the generation and review of exploration prospects, and participates in the planning, where necessary, to drill the prospects. These include prospects developed in-house, as well as those presented by other working interest partners. The office is also responsible for technical interpretation of geological and geophysical data for our development and acquisition activities and all land records for the Company.

All operated production activities are coordinated through our operations office in Cody, Wyoming. As of December 31, 2002 we operate 64% of our production.

Business Strategy

Our objective is to enhance shareholder value by increasing our net asset value through the consistent economic growth of our oil and gas reserves, production base and the resulting cash flows. To accomplish this, Equity's corporate strategy includes:

Operating efficiencies effective operation and management of our Rocky Mountain production to minimize operating costs and maximize oil production. Most of our oil production from the Rocky Mountain area comes from mature properties and production is on decline. For the properties to remain economic, we continually strive to reduce operating costs while implementing programs to increase the ultimate recovery of the original oil in place.

Exploitation of existing reserves we utilize the latest technology to enhance production from our reserve base. We conduct detailed geologic studies including 3D seismic imaging, hydraulic fracturing and reservoir stimulation techniques as well as water shut-off treatments.

Development drilling a portion of our budget is committed to low to medium-risk development drilling. During 2003 we anticipate drilling three development wells in the Sacramento Basin in the area of the properties acquired in 2002.

Focused exploration drilling we continue to allocate some of our resources to higher-risk focused exploration drilling with higher potential return. We plan to continue pursuing the drilling of another exploration well on our Beaver Creek prospect in North Dakota in 2003.

Acquisition of oil and gas properties we continue to focus on acquiring properties with primarily proved reserves which also have exploitation potential. We were successful this year in closing a major acquisition of gas properties in California.

Each project, whether development, exploration, acquisition or exploitation, undertaken in our core areas is independently evaluated to ensure that the estimated rate of return from the project is commensurate with the associated risk.

We work in conjunction with our other working interest owners in producing properties to identify projects that will develop and exploit the productive capacities of existing wells and fields. These projects include development drilling, production enhancement, operating cost reductions and other types of activities.

When conducting exploration activities, our general practice is to participate in projects on a 25% to 50% working interest basis. Participation varies with each prospect depending on location and the attendant financial and technical risk.

We also attempt to purchase interests in properties with existing production. During the last five years, we have replaced a significant amount of our production through the purchase of producing properties. These purchases have, in turn, produced additional developmental and enhancement projects, as well as opportunities to implement numerous procedures to increase operating efficiencies.

Symskaya's operations during 2002 were limited primarily to maintaining its license. At the end of 2002, due to the inability to attract a partner to participate in the cost of future development of the license area, it was determined that Symskaya would cease operations of this activity. Any costs incurred in 2003 will be associated with closing down all operations related to Symskaya. Further discussion of this venture can be found in **ITEM 2. Properties**, under the caption **Symskaya Exploration.**

Developments since December 31, 2001

The implementation of our strategy led to the following highlights for the year ended December 31, 2002:

Acquisition of gas properties. During the second quarter of 2002, the Company purchased working interests in 27 producing and 16 non-producing gas wells and associated undeveloped leaseholds located in Yolo County of the Sacramento Basin of California. The effective date of the acquisition was January 1, 2002 and was closed on April 12, 2002 and the Company assumed operations of the properties on May 1, 2002.

Reserve replacement of 2002 production. Taking into account extensions, discoveries, acquisitions and improved recovery and excluding revisions, we added 1.50 million barrels of oil and 24.9 billion cubic feet of gas to our reserve base. This replaces 236% and 594% of our 2002 net oil and gas production.

Development well drilling success. We participated in three development wells during 2002. All three wells were completed as gas wells in the Siberia Ridge field of Wyoming.

Workover activities. We successfully recompleted eight wells in Yolo County, California from the package of 27 wells that were acquired during the second quarter of 2002.

Production enhancement. The continued implementation of our polymer injection water shut-off treatment program in the Torchlight field in the Big Horn Basin added incremental year-end reserves.

Financial highlights. We recorded positive net income for the fourth consecutive year. Discretionary cash flow (defined as cash flow before working capital changes plus exploration and 3-D seismic costs) was $10.6 million and EBITDA (earnings before interest, taxes, depletion, abandoned leaseholds, property impairments and Symskaya loss) was $11.1 million. Book value per outstanding share increased from $2.75 to $2.77.

Principal products and markets

During the last five years, revenues from the sales of crude oil and natural gas have accounted for more than 90% of our total revenues. Remaining revenues have come from other sources, including interest income on invested funds, operating overhead reimbursements, and the sales of various developed and undeveloped properties.

The majority of our oil production occurs in Colorado, other Rocky Mountain states, and the Canadian provinces of Alberta and British Columbia. We are in the process of divesting some of our Canadian assets. See discussion of subsequent events at Footnote 12 in the financial statements for information related to the divestiture. Our crude oil production is sold under short-term contracts at current posted prices for each geographic area, less applicable quality adjustments, plus negotiated bonuses. Prices are set by oil purchasers, and, while their methods of determining prices are not within our control, it is assumed they are influenced by regional, national and international factors relating to oil supply and demand (see discussion under **Major Customers**).

The bulk of our natural gas production occurs in California, Wyoming, and the Canadian province of Alberta. We have historically been able to sell all of our production and expect to be able to continue to do so in the future even though other companies with larger reserves compete in the same areas. Our gas is sold under contracts based upon the daily spot market or marketed under contracts at index prices that change monthly. The contracts are subject to renegotiation on an annual basis.

In order to finance our acquisition activities we have been required by our lending institution to hedge a portion of our production in order to manage our exposure to oil and gas price volatility. The instruments are placed with counterparties that the Company believes are minimal credit risks, and it is the Company's policy to only enter into derivative contracts with investment grade rated counterparties deemed by management to be competent and competitive market makers. The oil and gas reference prices upon which the price hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by the Company.

As of December 31, 2002, the Company had commodity price hedges in place for 1,100 barrels of oil per day thru April 30, 2003 and 6,000 MMBTU of natural gas per day under costless collars (5,000 MMBTU thru April 30, 2004 and an additional 1,000 MMBTU thru December 31, 2003). The oil hedges have a floor of $23.00 and a ceiling of $27.10 and the gas hedges range from $3.00 per MMBTU to $4.915 per MMBTU.

Seasonality

Net gas sales prices historically have risen during the winter months compared to the rest of the year. With the recent acquisition of the gas properties in California, where change in price during the winter months is less dramatic than other areas, the seasonal impact has been reduced. Therefore, the seasonal impact on total gas sales is not significant.

Major Customers

All of the Company's oil and gas produced in the U.S. or Canada is sold to unaffiliated pipeline companies, refining companies or crude oil trading companies. These companies may be the operators of the fields where the product is produced, owners of the pipelines which transport the products, or other third-party purchasers.

During 2002, sales to two purchasers, Teppco Crude Oil, L.P. and Calpine Producer Services, L.P. accounted for 41% and 33%, respectively, of Equity's total oil and gas production revenue. While these entities each purchase more than 10% of our oil and gas production, previous changes in purchasers have not had a material adverse effect on our business.

Competition

The oil and gas industry is highly competitive. Competition is particularly intense in the acquisition of prospective oil and natural gas properties and oil and gas reserves. Equity's competitive position depends on our geological, geophysical and engineering expertise, our financial resources, and our ability to select, acquire and develop proved reserves.

We believe the locations of our leasehold acreage, our exploration, drilling and production capabilities, and the experience of our management and that of our industry partners generally enable us to compete effectively in our core operating areas. However, we compete with a substantial number of major and independent oil and gas companies having larger technical staffs and greater financial and operational resources. Securing drilling rigs and other equipment necessary for drilling and completion of wells may be in short supply from time to time due to this competition.

Environmental and Other Regulations

Our drilling activities are regulated by several governmental agencies in the United States, both federal and state, including the Environmental Protection Agency, Forest Service, Department of Wildlife and Bureau of Land Management, as well as state oil and gas commissions for those states in which we have operations. Canadian operations are subject to similar requirements.

Equity is committed to conducting its operations in a manner that protects the health and safety of its employees, contractors, and the public. Environmental, health and safety protection are integral parts of all of our business activities.

Although environmental, health and safety requirements do have a substantial impact upon the energy industry, generally these requirements do not affect us to any greater or lesser extent than other companies who operate in our core geographic areas and in the domestic oil and gas industry, as a whole. We believe that compliance with environmental laws and regulations will not have a material adverse effect on our operations or financial condition. However, there can be no assurances made that changes in, or additions to, laws or regulations regarding the protection of the environment will not have such an impact in the future.

Equity maintains insurance coverage that we believe is customary in the industry. We are not aware of any environmental claims existing as of December 31, 2002 that would have a material impact upon our financial position, results of operations, or liquidity.

Financial Information About Foreign Operations

Foreign operations are currently conducted in the Canadian provinces of Alberta and British Columbia. Financial information concerning these operations can be found in Footnotes 6 and 10 to the financial statements. See also Footnote 12 in the financial statements for a discussion of subsequent events related to the divestiture of our Canadian assets. For financial reporting purposes, we do not

allocate any general and administrative expenses to our Canadian operations, nor are they burdened with indirect exploration overhead expenses. Direct exploration expenses are charged to the geographic area in which they occur. Because the majority of our exploration efforts occur in the United States, very little exploration expenses are allocated to the Canadian operations. As a result of these and other factors, the operating profit of the Canadian operations is significantly greater than the operating profit in the United States. We do not believe that our Canadian operations are attended with any more risk than those in the United States.

ITEM 2. Properties

Equity's principal properties consist of developed and undeveloped oil and gas leasehold interests. Developed leases are comprised of properties with existing production, where lease terms continue as long as oil and/or gas is produced. Undeveloped leases include unproven acreage on both public and private lands. The leases have set terms and terminate at the time specified in each lease unless oil and/or gas in commercial quantities are discovered prior to that time. Undeveloped leaseholds at December 31, 2002 have a remaining life of one to five years.

Equity's exploration, development and acquisition activities are focused in the Big Horn Basin (WY), other Rocky Mountain states, the Sacramento Basin (CA), and Canada. We announced in September 2002 our intent to sell a portion of our Canadian oil and gas assets. See discussion of subsequent events at Footnote 12 in the financial statements for information related to the divestiture.

We finance our activities through cash flows from operations and through borrowings under our credit facility. In accordance with our credit facility, core properties are mortgaged as security for the amounts borrowed under the facility. Set forth below is summary information as of and for the year ended December 31, 2002 concerning exit rate average net daily production, net producing wells, proved reserve quantities and net present value in our major areas of operations.

	Year-end 2002 Exit Rate Average Net Daily Production		As of December 31, 2002					
				Proved Reserve Quantities (In 000's)			PV-10 Net Present Value (In 000's)	
	Boe/d	%	Net Producing Wells	Crude Oil-Bbls	Natural Gas-Mcf	Boe Total	Amount	Percent
Big Horn Basin	512	13.9%	40.7	3,689	1,857	3,999	$ 23,003	15.7%
Other Rockies	1,095	29.8	58.4	5,273	8,994	6,772	57,593	39.4
Sacramento	1,689	46.1	29.8		22,945	3,824	53,210	36.4
Canada	339	9.2	17.8	1,581	2,792	2,046	12,516	8.5
Other	30	1.0	.4	6		6	20	
Total	3,665	100.0%	147.1	10,549	36,588	16,647	$ 146,342	100.0%

Big Horn Basin

The Big Horn Basin of northwestern Wyoming has been a focus area for Equity since 1997. Our operations are managed by our Cody, WY office which includes 12 employees.

Our Big Horn Basin properties are typically long-lived high water cut oil fields which benefit from our expertise in lift optimization. We operate 93 wells in the basin producing 800 barrels of oil per day. Our working interest in these wells range from 30% to 100%.

Our most significant asset in the Big Horn Basin is our 100% working interest in the Torchlight Field. During 2002, we continued our water shut-off treatment program in the field, successfully treating three wells during 2002. Since 1997 when we completed acquisition of the 100% working interest in the field and took over operations, through a combination of these water shut-off treatments, development drilling and other workovers we have increased production in the field by 37%

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to its current daily rate of 280 barrels of oil per day and reserves have increased 2.7 million barrels at year-end 2002. We expect to perform six additional water shut-off treatments during 2003.

Other Rocky Mountain States

Williston Basin, North Dakota: In 2002 we drilled our first wildcat on the Beaver Creek 3-D prospect area, the BTA #1B Equity Redtail. This was a new field discovery in the Williston Basin. The well is a Red River "C" discovery, drilled to a 12,720 foot true vertical depth. Initial gross flow rate was 232 barrels of oil per day. Equity has a 50% working interest in the well.

On our Roosevelt Creek seismic project, a 24 mile 3-D survey was completed in the fourth quarter and is being interpreted. The project covers approximately 14,500 acres. With interpretation, we believe several drillable prospects may be generated in the area. The project is adjacent to our Beaver Creek acreage and extends to 63 square miles the amount of propriety 3-D seismic that we have acquired in this prolific Red River-Nisku trend.

Siberia Ridge, Southwestern Wyoming: We participated in the drilling of three development wells in this field in 2002. Two of the wells were drilled and completed by Anadarko Petroleum. The first, completed in May 2002 was completed at an initial gross rate of 775 Mcf per day. The second was being completed at year-end. We have a 50% working interest in both of these wells. The third well in which we have a 75% working interest was drilled by Samson Resources, it was also being completed at year-end and has a projected initial production rate of 1.1 Bcf per day with production anticipated to begin in March 2003.

Other: We have a fee interest in 6,996 net acres of oil shale lands in the Piceance Basin of Colorado. These properties have not generated significant revenue for the Company.

Sacramento Basin

During the second quarter of 2002, we purchased interests in 27 producing and 16 non-producing gas wells and associated undeveloped leaseholds located in Yolo County, California. This Sacramento Basin acquisition was closed on April 12, 2002 with an effective date of January 1, 2002. The interests acquired are working interests and we assumed operations of the properties on May 1, 2002. The total consideration for the properties was $32.0 million. Net proceeds from the effective date to the date of closing were netted against the purchase price and thus approximately $30.0 million was paid at closing.

The Yolo County properties now represent our largest core area. At year-end 2002, the Yolo County properties had proven gas reserves of 21.7 billion cubic feet with an SEC 10 net present value of $50.7 million. The year-end SEC value was computed using a net price of $4.56 per MMBTU. During 2002, we completed eight behind-pipe recompletions, initiating the validation of the behind-pipe component of the acquisition. We own a 100% working interest in most of the wells. We expect to recomplete another twelve wells in 2003 and a similar number per year for the next several years.

We also have interpreted 3-D seismic data covering the Yolo county properties acquired from the previous owner. The 3-D data has and will continue to assist the Company in refining our geological and geophysical model for drilling in 2003 and future years. Our 2003 budget includes drilling one exploration well, three development wells and the twelve behind-pipe recompletions mentioned above.

Canada

We announced in September 2002 our intent to sell a portion of our Canadian assets. At December 31, 2002 our Canadian properties were producing approximately 340 barrels of oil equivalent per day. This represented about 9% of our daily production. The sale of these assets will allow us to further focus on growth in our other core operating areas of the Rocky Mountains and the Sacramento

Basin. See discussion of subsequent events in footnote 12 to the financial statements for the status of this divestiture.

Reserves

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of exploitation expenditures. The data in the following tables represent estimates only. Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of hydrocarbons that cannot be measured exactly, and estimates of other engineers might differ materially from those shown above. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgement. Results of drilling, testing and production after the date of the estimate may justify revisions. Accordingly, reserve estimates may vary from the quantities of oil and natural gas that are ultimately recovered.

Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The present value shown should not be construed as the current market value of the reserves. The 10% discount factor used to calculate present value, which is mandated by the Securities and Exchange Commission rules, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

At December 31, 2002, we evaluated our oil and gas properties and our evaluation was audited by the outside engineering firm of Fred S. Reynolds and Associates. The PV-10 values (future estimated net revenues discounted at 10%) shown in the following table are prepared in accordance with SEC guidelines and are not intended to represent the current market value of the estimated net oil and gas reserves owned by Equity Oil Company. Neither prices nor operating costs have been escalated in this evaluation.

The following table sets forth summary information with respect to the estimates of our net reserves for each of the years in the three-year period ended December 31, 2002:

	As of December 31,		
	2002	**2001**	**2000**
Reserves Data:			
Oil Mbbls(a)	10,549	8,581	9,129
Gas Mmcf(b)	36,588	16,579	16,991
MBOE(c)	16,647	11,344	11,961
PV-10 value, excluding income taxes (in 000's)	$ 146,342	$ 39,131	$ 121,869
Proved Developed Reserves	86%	92%	91%
Production Replacement, excluding revisions	424%	205%	97%
Life (years)(d)	12.5	12.8	12.7

(a) Thousands of barrels

(b) Thousands of mcf

(c) Gas converted at a ratio of 6,000 mcf per barrel

(d)

Year end reserves divided by annual production

The present value of estimated future net revenues before income taxes of our reserves was $146 million as of December 31, 2002. This present value is based on a benchmark of prices in effect at that date of $31.20 per barrel of oil and $4.79 per MCF of gas. Both of these prices are then adjusted for transportation and basis differential for each property resulting in net average prices for the Company of $27.01 per barrel of oil and $4.09 per MCF of natural gas at year-end. These prices were 57 percent and 86 percent higher, than prices in effect at the end of 2001.

Proved developed reserves are proved reserves that are expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled to known reservoirs on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells where a relatively major expenditure is required to establish production.

No estimates of reserves have been filed with or included in any report to any other federal agency during 2002.

Production

The following table sets forth Equity's production, average sales prices and average lifting costs by geographic area for 2002, 2001 and 2000:

	2002 Oil (Bbls)	2001 Oil (Bbls)	2000 Oil (Bbls)	2002 Gas (MMCF)	2001 Gas (MMCF)	2000 Gas (MMCF)
Production						
Colorado	245,478	265,145	272,855	44	58	76
Texas	12,802	13,650	13,879			
Montana	19,475	24,726	21,590	32	32	32
Utah	30,667	34,359	18,194			
Wyoming	193,233	170,282	174,556	517	551	557
North Dakota	33,258	45,445	92,744	16	28	64
California				3,331	539	732
Total U.S.	534,913	553,607	593,818	3,940	1,208	1,461
Alberta	88,704	74,596	61,732	255	281	186
B.C.	10,237	9,010	10,300	3	7	14
Total Canada	98,941	83,606	72,032	258	288	200
Grand Total	633,854	637,213	665,850	4,198	1,496	1,661
Average Price						
U.S.	$ 22.26*	$ 22.65	$ 26.55*	$ 2.51*	$ 4.89	$ 4.02
Canada	$ 20.35	$ 16.43	$ 26.29	$ 2.10	$ 3.13	$ 3.51
Total	$ 21.97	$ 21.84	$ 26.52	$ 2.48	$ 4.55	$ 3.96
Lifting Costs						
U.S.	$ 7.93	$ 7.32	$ 7.51	$ .89	$ 1.58	$ 1.14

	2002 Oil (Bbls)	2001 Oil (Bbls)	2000 Oil (Bbls)	2002 Gas (MMCF)	2001 Gas (MMCF)	2000 Gas (MMCF)
Canada	$ 6.77	$ 5.55	$ 6.12	$ .61	$ 1.04	$ .82
Total	$ 7.75	$ 7.08	$ 7.36	$ .88	$ 1.47	$ 1.10

* includes the effect of hedging costs.

Productive Wells and Acreage

The location and quantity of our productive wells and acreage as of December 31, 2002 are as follows:

Productive Wells:	Gross	Net
Oil:		
United States	666	86.57
Canada	224	15.77
Gas:		
United States	85	42.73
Canada	11	2.05
Total Productive Wells	986	147.12
Developed Acreage		
United States	113,848	14,085
Canada	128,520	3,461
Total Developed Acreage	242,368	17,546

Undeveloped Leasehold Acreage

The following table sets forth Equity's undeveloped oil and gas leasehold acreage as of December 31, 2002 by geographic area:

Area	Gross Acreage	Net Acreage
Colorado	24,616	5,781
Texas	1,197	252
Montana	20,266	5,383
Utah	45,191	20,046
Wyoming	48,073	28,156
California	16,913	6,515
North Dakota	21,489	12,342

Area	Gross Acreage	Net Acreage
Total U.S.	177,745	78,475
Alberta	17,960	2,826
Total Canada	17,960	2,826
Grand Total	195,705	81,301

Drilling Activity

During 2002, we participated in the drilling of 8 gross wells. Of this total, 4 were completed as producing oil and gas wells, 2 were waiting on completion at year-end and 2 were plugged and abandoned as dry holes.

	Status	2002	2001	2000
Gross exploratory wells drilled:				
United States	Productive	3		3
	Dry	2	4	6
Canada	Productive			
	Dry			
Gross development wells drilled:				
United States	Productive	3	6	1
	Dry		1	
Canada	Productive		6	8
	Dry			

	Status	2002	2001	2000
Net exploratory wells drilled:				
United States	Productive	.62		.75
	Dry	.73	1.49	3.35
Canada	Productive			
	Dry			
Net development wells drilled:				
United States	Productive	1.75	3.66	.30
	Dry		.55	
Canada	Productive		3.00	3.19
	Dry			

Symskaya Exploration

At the end of 2002 we continued to hold our 50% ownership position in Symskaya Exploration Inc. In 1993 Symskaya was issued a 25 year, 1.1 million acre license to explore for, develop and produce hydrocarbons in the Krasnoyarsk Krai in Russia. Since 1997 we have made extensive efforts to attract investors to commit funding for additional exploration on the Symskaya license area. These efforts have been unsuccessful, and in December of 2002 Symskaya determined they would cease operations in Russia as of December 31, 2002. The second half of the 2002 land use fee required under the license was not paid nor was an installment of a newly imposed exploration fee. Costs associated with this prospect in 2003 will be associated with closing down all operations and interest in Russia and, if possible, the transfer of Symskaya to another entity that may choose to pursue further exploration on the license area. If such a transfer should occur, the Company will endeavor to retain some form of interest in possible future production from the project.

Delivery Commitments

Equity is not obligated to provide any fixed or determinable quantities of oil or gas in the future under any existing contracts or agreements.

ITEM 3. Legal Proceedings

No material legal proceedings were settled or pending.

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

No items were submitted during the fourth quarter of the fiscal year covered by this Form 10-K to a vote of our security holders, through the solicitation of proxies or otherwise.

PART II

ITEM 5. Market for the Company's Common Stock and Related Stockholder Matters

Equity's common stock is traded on the over-the-counter market and quoted over the NASDAQ National Market System under the symbol EQTY. The range of high and low closing prices for the quarterly periods in 2002 and 2001, as reported by NASDAQ is set forth below:

Quarter		High	Low
2002	4th	$ 2.31	$ 1.75
	3rd	$ 2.60	$ 2.00
	2nd	$ 2.45	$ 1.90
	1st	$ 2.07	$ 1.65
2001	4th	$ 2.44	$ 1.66
	3rd	$ 3.10	$ 2.10
	2nd	$ 3.50	$ 2.95
	1st	$ 4.06	$ 3.00

As of February 24, 2003, as shown on the most recent proxy certified listing from our transfer agent, the number of record holders of Equity Oil's common stock was 1,212. Management believes, after inquiry, that the number of beneficial owners of our common stock is in excess of 4,000.

We have sold no unregistered equity securities during the period covered by this report.

No dividends were paid during the year. Currently, the payment of dividends is not allowed under the provisions of our credit facility without obtaining a waiver from the lender. Payment of any future dividends will be at the discretion of our board of directors after taking into account many factors, including our financial condition, operating results, current and anticipated cash needs and plans for expansion.

ITEM 6. Selected Financial Data

The following table sets forth selected financial data for Equity as of the dates and for the periods indicated. The financial data for each of the five years ended December 31, 2002 is derived from financial statements which have been audited by PricewaterhouseCoopers LLP, independent public accountants. The following data should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations," which includes discussion of factors materially affecting the comparability of the information presented, and in conjunction with Equity's financial statements included elsewhere in this report.

	Years Ended December 31,				
	2002	2001	2000	1999	1998
Oil and Gas Sales	$ 24,343,277	$ 20,590,476	$ 24,316,369	$ 15,434,537	$ 12,720,876
Other Income	309,282	344,378	1,082,653	334,980	377,282
Lease Operating Costs	8,586,946	6,720,610	6,726,769	5,948,055	6,233,955
Depreciation, Depletion and Amortization	7,674,633	4,197,543	3,808,777	4,072,278	5,029,119
Impairment of Proved Oil and Gas Properties	53,990	404,395	368,543	313,751	4,015,158
Equity Loss and Impairment of Investment in Symskaya Exploration, Inc.	178,512	161,494	174,432	169,933	446,758
3-D Seismic	215,339	697,676	979,028	35,200	431,075
Exploration Expense	908,379	594,336	1,337,593	567,076	1,072,030
General and Administrative	2,409,304	2,440,241	1,897,190	1,743,590	1,914,590
Net Income (Loss)	1,001,077	2,281,117	5,164,071	403,521	(5,814,884)
Basic Net Income (Loss) Per Common Share	$ .08	$ .18	$ .41	$ .03	$ (.46)
Diluted Net Income (Loss) Per Common Share	$ .08	$ .18	$ .40	$ .03	$ (.46)
Total Assets	$ 76,800,356	$ 48,309,335	$ 47,797,711	$ 46,117,335	$ 47,271,168
Long-Term Debt	$ 34,500,000	$ 5,500,000	$ 8,500,000	$ 15,000,000	$ 16,500,000

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

GENERAL.

Our profitability from operations in any particular reporting period will be directly related to the average realized prices of oil and gas sold, the volume of oil and gas produced and the results of acquisition, development and exploration activities. The average realized prices of oil and gas will fluctuate from one period to another due to market conditions and the results of the Company's hedging activities. The aggregate amount of oil and gas produced may fluctuate based on our development and exploitation of oil and gas reserves and other factors. Production rates, value-based production taxes, labor and maintenance expenses are expected to be the principal influences on operating costs. Accordingly, our results of operations may fluctuate from period to period.

Equity uses the successful efforts method of accounting for oil and natural gas activities. Under this method, only the cost of successful efforts are capitalized as oil and gas properties. Costs of exploratory dry holes, geological and geophysical costs, delay rentals, general and administrative costs associated with our exploration efforts and other property carrying costs are expensed as incurred.

Prices received from the sale of oil and natural gas during 2002 were higher than the prices that were in effect at year-end 2001. The prices received for our oil vary from NYMEX prices based on the location and quality of the crude oil. The prices we receive for our natural gas are based upon posted prices in the area where the gas is produced, reduced by transportation charges and processing fees. Transportation costs are comprised of costs paid to a carrier to deliver oil or natural gas to a specified delivery point.

Oil and natural gas production costs are composed of lease operating expense and production taxes. Lease operating expense consists of pumpers' salaries, utilities, maintenance and other costs necessary to operate our producing properties. Production taxes are assessed by applicable taxing authorities as a percentage of revenues.

Exploration expense consists of geological and geophysical costs, delay rentals and cost of unsuccessful exploratory wells. Delay rentals and some overhead costs are typically fixed in nature in the short term. However, other exploration costs are generally discretionary and exploration activity levels are determined by a number of factors, including oil and natural gas prices, availability of funds, quantity and character of investment projects, availability of service providers and competition. Production and exploration overhead expense consists of exploration staff overhead costs, technical and production office expenses and production staff overhead costs that are not directly billed to our producing properties.

Depletion, depreciation and amortization of capitalized costs of producing oil and natural gas properties is computed using the unit-of-production method based on proved reserves. For purposes of computing depletion, proved reserves are redetermined as of the end of each year. Because the economic life of each producing well depends upon assumed prices, fluctuations in oil and gas prices impact the level of proved reserves. Higher prices generally have the effect of increasing reserves, which reduces depletion, while lower prices generally have the effect of decreasing reserves, which increases depletion expense.

CRITICAL ACCOUNTING POLICIES

A summary of our significant accounting policies is included in Footnote 1 of our financial statements. We believe the application of these accounting policies on a consistent basis enables us to provide timely and reliable financial information about our earnings results, financial condition and cash flows.

The preparation of financial statements in accordance with generally accepted accounting principles requires management to make judgements, estimates and assumptions regarding uncertainties that affect the reported amounts presented and disclosed in the financial statements. Our management reviews these estimates and assumptions based on historical experience, changes in business conditions and other relevant factors that they believe to be reasonable under the circumstances. In any given reporting period, actual results could differ from the estimates and assumptions used in preparing our financial statements.

Critical accounting policies are those that may have a material impact on our financial statements and also require management to exercise significant judgement due to a high degree of uncertainty at the time the estimate is made. Our senior management has discussed the development and selection of our accounting policies, related accounting estimates and the disclosures set forth below with the Audit Committee of our Board of Directors. We believe our critical accounting policies include those addressing the recoverability and useful lives of assets, oil and gas reserve estimates and income taxes.

The computation of the Company's income tax expense requires the interpretation of complex tax laws and regulations in many taxing jurisdictions in the United States and Canada as well as any possible assessments due to audit findings that may be performed by numerous taxing authorities. Actual income tax expense can differ significantly from management's estimates.

OIL AND GAS RESERVES

Estimates of reserve quantities and related future net cash flows are calculated using unescalated year-end oil and gas prices and operating costs, and may be subject to substantial fluctuations based on the prices in effect at the end of each year. The following table sets forth a comparison of year-end reserves, the weighted average prices used in calculating estimated reserve quantities and future net cash flows, pre-tax future net cash flows discounted at 10%, and per barrel of oil equivalent discounted

cash flows at the end of 2002, 2001 and 2000 (quantities in thousands, except for pricing and per barrel of oil equivalent amounts):

	Year-end proved reserves			Year-end prices			
	Oil(MBBLs)	Gas(MMCF)	BOE*	Oil	Gas	SEC-10 pre-tax values	SEC-10 pre-tax values per BOE
12/31/02	10,549	36,588	16,648	$ 27.01	$ 4.09	$ 146,342	$ 8.79
12/31/01	8,581	16,579	11,344	$ 16.03	$ 2.15	$ 39,131	$ 3.45
12/31/00	9,129	16,991	11,961	$ 23.78	$ 10.39	$ 121,869	$ 10.19

* gas converted at 6,000 Mcf per barrel.

Reserve revisions occur, among other things, when the economic limit of a property is lengthened or shortened due to changes in commodity pricing. The following table shows the effect of changing oil prices on the volume of oil reserves (shown in thousands of barrels):

	Year ended December 31,		
	2002	2001	2000
Proved oil reserves (000's):			
Beginning of year	8,581	9,129	9,293
Revisions of previous estimates	1,105	(1,388)	203
Extensions and discoveries	367	350	503
Improved recovery	1,130	862	190
Acquisition of minerals in place		265	46
Sales of minerals in place			(440)
Production	(634)	(637)	(666)
End of year	10,549	8,581	9,129

Oil prices increased from year-end 2001 to year-end 2002 ($16.03 vs. $27.01, respectively). The upward revision of 1,105,000 in 2002 and 203,000 in 2000 and the downward revision of 1,388,000 in 2001 were primarily price-related.

Excluding revisions to previous estimates, our 2002 drilling and acquisition activities added 5,651,600 barrels of oil equivalent reserves, 424% of 2002 total oil and gas production.

In 2001, we replaced 205% of our total oil and natural gas production through our drilling and acquisition activities. In 2000, drilling and acquisition activities added 913,000 barrels of oil equivalent to our proved reserve base, replacing 97% of 2000 production. Further information concerning our reserve volumes and values can be found in Footnote 10 to the financial statements.

IMPAIRMENT OF PROVED OIL AND GAS PROPERTIES

We assess our proved properties on a field-by-field basis for impairment, in accordance with the provisions of Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," whenever events or circumstances indicate that the capitalized cost of oil and natural gas properties may not be recoverable. When making such assessments, we compare the expected undiscounted future net revenues on a field-by-field basis with the related net capitalized costs at the end of each period. When the net capitalized costs exceed the undiscounted future net revenues, the cost of the property is written down to "fair value," which is determined using discounted future net revenues. Reserve categories used in the impairment analysis considered all categories of proven reserves and probable and possible reserves, which are risk-adjusted based on our drilling plans and history of successfully developing those types of reserves.

During 2002, we recorded an impairment of oil and gas properties of $53,990 associated with certain properties that experienced increased operating costs, declining production, reduced prospectivity due to unsuccessful drilling, and other technical problems that reduced their economic reserves. During 2001 and 2000, we recorded impairment charges of $404,395 and $368,543, respectively.

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RESULTS OF OPERATIONS

Comparison of 2002 with 2001

Oil and gas production and sales. Gas volumes from the gas properties acquired in 2002 offset slightly lower oil volumes and lower natural gas prices as compared to 2001. This allowed the Company to record oil and gas sales of $24,343,277 in 2002 compared to $20,590,476 in 2001, an 18% increase. Gas revenues from the assets acquired in 2002 were approximately $7.9 million.

We periodically enter into hedging activities for a portion of our oil and natural gas production as a requirement of our new bank credit facility, to support our oil and natural gas price at targeted levels and to manage our exposure to price fluctuations. Starting in May 2002 we had commodity price hedges in place for 1,100 barrels of oil a day and 8,000 MMBTU of natural gas per day under costless collars. The settlement price of each of the contracts during the year resulted in the Company making payments to the counterparty of approximately $305,000. These payments are netted against oil and gas revenues. No such payments were made in 2001 as we had no volumes of oil or natural gas subject to hedging agreements. As of January 1, 2003, we had 1,100 barrels of oil per day thru April 30, 2003 and 6,000 MMBTU of natural gas per day (5,000 MMBTU thru April 30, 2004 and 1,000 MMBTU thru December 31, 2003) subject to hedging arrangements under costless collars.

Year-end 2002 company received commodity prices were much higher than the prior year-end ($27.01 in 2002 compared to $16.03 in 2001 for oil and $4.09 in 2002 compared to $2.15 in 2001 for natural gas). However, average oil prices received for the full year 2002 were only slightly higher compared to the prior year. The average 2001 price received was $21.84 per barrel. After taking into consideration the hedging costs discussed above, the average oil price received in 2002 was $21.97 per barrel.

Average received gas prices were down sharply for 2002 when compared to 2001. After taking into consideration the hedging costs discussed above, the average gas price received in 2002 was $2.48 per Mcf compared to $4.55 per Mcf in 2001 or a 45% decrease.

Oil production remained relatively constant from 637,000 barrels in 2001 to 634,000 barrels in 2002. Gas production in 2002 was substantially higher in 2002 when compared to 2001, 4,198,000 Mcf compared to 1,496,000 Mcf last year. The oil production decline is attributable to normal production declines as our properties mature. The increase in gas production is attributable to the acquisition of the Sacramento Basin gas properties during the year. Production from the acquired properties was approximately 3.0 Bcf of gas.

Other income. Included in 2001 other income is $85,000 in non-recurring property sales recognized in the first quarter of the year. In 2002 these non-recurring property sales were minimal.

Lease operating costs. Operating costs in 2002 increased by 28% or about $1.87 million. Costs associated with the acquired gas properties accounted for approximately $1.0 million of the increase. The additional increase results from an adjustment in the fourth quarter of 2001 to reverse the accrual of $888,000 of prior years' production taxes and other operating costs.

Depreciation, depletion and amortization (DD&A). DD&A per unit charges increased 22% from $4.73 per BOE in 2001 to $5.75 per BOE in 2002. This increase is the result DD&A attributable to the acquired gas properties. The acquired gas properties have a shorter life than our other assets thus DD&A on a per unit basis increased. DD&A charges attributable to the acquired assets was approximately $3.8 million.

Impairment of proved oil and gas properties. As discussed previously, included in the statement of operations for 2002 and 2001 are non-cash charges for the impairment of proved oil and gas properties in the amount of $53,990 and $404,395, respectively.

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3-D seismic and exploration expenses. We participated in one new 3-D seismic survey during 2002. The survey was a 24 square mile survey adjacent to our South West Beaver Creek prospect in North Dakota. Our share of the cost, approximately $215,000, was charged to expense during the year. During 2001 we participated in two surveys with higher working interests resulting in an expense of approximately $698,000.

Higher exploration costs in 2002 reflected higher dry hole costs incurred during the year. We drilled two dry holes in 2002 compared to five in the prior year. The majority of the 2002 dry hole expense was associated with one well in which we had a 47.5% working interest. The working interest percentages for all of the dry holes in 2001 were much lower than 47.5%. Dry hole costs in 2002 were approximately $315,000 higher than the amount recorded in 2001.

General and administrative expenses. General and administrative expenses were unchanged from the prior year. Costs incurred in both 2002 and 2001 were about $2.4 million. Lower compensation related costs and other administrative costs in 2002 were offset by higher insurance expense, shareholder costs and costs associated with the pursuit of acquisition and divestiture opportunities during the year.

Production and exploration overhead expense. Production and exploration overhead expenses are salaries and benefits for employees who oversee our production and exploration activities and costs related to maintaining our technical office in Denver, Colorado and our operations office in Cody, Wyoming. These costs were only slightly lower in 2002 when compared to 2001, $1.42 million compared to $1.44 million.

Interest and income taxes. Higher interest costs in 2002 reflect higher balances outstanding under our credit facility. The increase in the amount outstanding resulted from our 2002 property acquisition. The acquisition was paid for through borrowing approximately $31.5 million dollars during the second quarter of 2002.

Income tax expense for both periods reflects the results of operations, as well as the utilization of various credits and other tax attributes. Details concerning the components of the tax provision can be found in Footnote 4 to the financial statements.

Other comprehensive loss. Other comprehensive loss for the period reflects the fair value of our commodity hedges, net of income taxes, that were in place at December 31, 2002. The fair value is computed by the counterparty using a financial modeling technique including a type of Black-Scholes method. The counterparty valued the hedges at December 31, 2002 at ($1,917,988). This amount is included in the balance sheet as fair value of financial instruments and the tax effected amount, ($1,208,908), is reported in other comprehensive income. We do not intend to terminate our current commodity hedges prior to their expiration date.

Comparison of 2001 with 2000

Oil and gas production and sales. Lower fourth quarter commodity prices resulted in lower oil and natural gas revenues for 2001. Oil and gas sales for the year of $20,590,476 were 15% lower than those recorded in 2000, as year-end average oil and gas prices were 33% and 79% lower, respectively.

During 2001 we had no volumes of oil or natural gas subject to hedging agreements. Revenues were reduced by $1,048,018 in 2000 by costs associated with our hedging program.

While we may hedge future volumes as a means to mitigate price risk and/or to ensure the availability of capital to fund our drilling programs, there was no requirement to hedge under our previous banking arrangement during 2001. As of January 1, 2002, we had no volumes of oil or gas subject to hedging arrangements.

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The average oil price received for 2001 was $21.84 per barrel, down 18% from the prior year. After taking into consideration the hedging costs discussed above, the average oil price received in 2000 was $26.52 per barrel.

Gas prices were up sharply the first half of 2001, however prices declined substantially during the second half resulting in an average price of $4.55 per Mcf for the entire year. This compared to $3.96 per Mcf in 2000 or a 15% increase.

Oil production declined from 666,000 barrels in 2000 to 637,000 barrels in 2001. Gas production in 2001 was 1,496,000 Mcf compared to 1,661,000 Mcf in 2000. The oil production decline is attributable to normal production declines as our properties mature. The reduction in gas production was due in part to our reduced drilling program and reduced drilling success in California during 2001.

Other income. Included in 2000 other income is $506,000 in non-recurring property sales recognized in the first quarter of the year. In 2001 these non-recurring property sales were only $85,000. We also recognized gains in 2000 on the sale of securities held for investment and revenue from property promotions that were non-recurring.

Lease operating costs. Operating costs in 2001 were unchanged from 2000 levels due to the fourth quarter reversal of prior years' production taxes and other operating costs that had been previously accrued by the Company. The adjustment during the fourth quarter, to reflect the settlement of these previously estimated costs was approximately $888,000. Without this reversal, operating costs would have increased approximately 13% from the prior year. The most significant factor leading to this increase was lease operating expenses associated with plugging and abandonment charges for old inactive wells in some of our mature oil fields. Additionally, higher oil and gas prices during the first half of the year resulted in higher value-based production taxes.

Depreciation, depletion and amortization (DD&A). DD&A per unit charges increased 17% from $4.04 per BOE in 2000 to $4.73 per BOE in 2001. This increase is the result of lower year-end commodity prices which reduced year-end reserves and resulted in a higher unit-of-production depletion rate for the fourth quarter of 2001.

Impairment of proved oil and gas properties. As discussed previously, included in the statement of operations for 2001 and 2000 are non-cash charges for the impairment of proved oil and gas properties in the amount of $404,395 and $368,543, respectively.

3-D seismic and exploration expenses. We participated in four new 3-D seismic surveys during 2001. The first was a 15 square mile survey at our South West Beaver Creek prospect in North Dakota. The second was a 10 mile survey at the North Ellsworth prospect also in North Dakota. The costs of both surveys, approximately $698,000, were charged to expense during the year. The other two surveys were conducted over producing areas and thus costs were capitalized to the cost of the producing properties. The capitalized cost was approximately

$245,000. We participated in two 3-D seismic surveys during 2000. The cost of approximately $979,000 was charged to expense in 2000.

Lower exploration costs in 2001 reflected lower dry hole costs incurred during the year. We drilled one less dry hole in 2001 than in 2000. Additionally the wells drilled in 2001 carried an average lower working interest than those of the previous year. Dry hole costs in 2001 were approximately $760,000 lower than the amount recorded in 2000.

General and administrative expenses. General and administrative expenses increased 29% from 2000 levels. The increase was due to higher compensation resulting from bonus payments, fees paid to an employee search firm associated with hiring a new vice president of corporate development, employee relocation costs for two new employees, and higher shareholder expenses.

Production and exploration overhead expense. Production and exploration overhead expenses increased in 2001 from 2000 levels, $1.44 million in 2001 compared to $1.18 million in 2000. The primary factor causing this increase was higher salary and benefit costs during 2001.

Interest and income taxes. Lower interest costs in 2001 reflect lower balances outstanding under our credit facility and lower interest rates on the outstanding balance. During 2001, we reduced our credit facility debt by $3,000,000.

Income tax expense for both periods reflects the results of operations, as well as the utilization of various credits and other tax attributes. Details concerning the components of the tax provision can be found in Footnote 3 to the financial statements.

LIQUIDITY AND CAPITAL RESOURCES

During the year we secured a new $75 million credit facility for the purpose of acquiring certain gas properties in California. The acquisition of these assets closed in April 2002 for approximately $30 million. This represented the largest capital expenditure outlay in our 80-year history. Even though we are more highly leveraged than at any time in our history, we believe the cash flow from these acquired properties will support the amount of debt outstanding. Further, the additional cash flow will give us opportunities to continue to grow the asset value of the Company.

Our cash balances increased by 40% from the amount at December 31, 2001. Our current assets to current liabilities ratio excluding the accrued liability for fair value of financial instruments increased to 2.58 to 1 at December 31, 2002 compared to 1.74 to 1 at the end of 2001. These increases are due to additional oil and gas receivables primarily attributable to the California gas acquisition and higher prices in effect at year-end 2002 when compared to 2001. Additionally, year-end 2001 reflected accrued expenses in connection with the aggressive drilling activities we pursued during the fourth quarter of that year.

Capital expenditures increased 512% over 2001 levels, reaching approximately $35.9 million in 2002 ($30.7 million of these costs were for the acquired properties as discussed above).

Our new $75 million revolving credit facility with Bank One Texas, N.A. was secured in April 2002. The facility has a current commitment of $38 million. The facility has a LIBOR or a prime interest rate option; the weighted average interest rate on debt outstanding at December 31, 2002 was 3.76 percent.

The commitment under our credit facility is subject to a redetermination as of April 1 and October 1 of each year, with estimated future oil and gas prices used in the evaluation determined by the lender. As of December 31, 2002, we had $3,500,000 of remaining availability on the facility. We are in compliance with all facility covenants.

Excess cash flows in 2002 enabled us to pay down our debt to $34.5 at year-end. Should we have cash flows in excess of our capital requirements for 2003, additional reductions of outstanding debt may occur.

Cash flow from operating activities of $9,559,313 was 26% higher than the amount recorded during 2001. Increased oil and gas revenues was the primary driver for the increase.

Accounts receivable at year-end 2002 were approximately $3.9 million which was $1.5 million higher than at year-end 2001. The increase is related to gas sales from the acquired assets and higher year-end 2002 commodity prices. The decrease in accounts payable in 2002 reflected less drilling activity at the end of the year when compared to year-end 2001. Income taxes receivable decreased due to refunds that were received as a result of the tax net operating loss incurred in the prior year.

We believe that our capital resources from existing cash balances, cash flow from operating activities, and funds available under our credit facility are adequate to meet the requirements of our

business. However, future cash flows are subject to a number of variables, including the level of production and oil and natural gas prices. We cannot assure that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures or that increased capital expenditures will not be undertaken. We believe we have adequate liquidity to maintain our operations as they currently exist.

Contractual Obligations and Contingent Liabilities and Commitments.

We have no significant off-balance sheet transactions or similar instruments and we are not a guarantor of any other entities' debt of other financial obligations.

The following table sets forth payments due by period for contractual obligations as of December 31, 2002:

	Total	0-3 Years
Revolving credit facility	$ 34,500,000	$ 34,500,000

RECENTLY ISSUED FINANCIAL ACCOUNTING STANDARDS

We have reviewed all recently issued, but not yet adopted accounting standards in order to determine their effects, if any, on the results of our operations or financial position. Based on that review, we are continuing to evaluate the impact of adopting SFAS 143 and we believe that all other pronouncements will not have any significant effects on our future earnings or operations. Further discussion of recently issued accounting standards is found in Footnote 11 to the financial statements.

FORWARD LOOKING STATEMENTS

The preceding discussion and analysis should be read in conjunction with the consolidated financial statements, including the notes thereto, appearing elsewhere in this annual report on Form 10-K. Except for the historical information contained herein, the matters discussed in this annual report contain 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, that are based on management's beliefs and assumptions, current expectations, estimates, and projections. Statements that are not historical facts, including without limitation statements which are preceded by, followed by or include the words "believes," "anticipates," "plans," "expects," "may," "should" or similar expressions are forward-looking statements. Many of the factors that will determine our future results are beyond the ability of the Company to control or predict. These statements are subject to risks and uncertainties and, therefore, actual results may differ materially. All subsequent written and oral forward-looking statements attributable to Equity, or persons acting on its behalf, are expressly qualified in their entirety by these cautionary statements. We disclaim any obligation to update any forward-looking statements whether as a result of new information, future events or otherwise.

Important factors that may affect future results include, but are not limited to: drilling success, the risk of a significant natural disaster, our inability to insure against certain risks, fluctuations in commodity prices, the inherent limitations in the ability to estimate oil and gas reserves, changing government regulations, as well as general market conditions, competition and pricing, and other risks detailed from time to time in our SEC reports, copies of which are available upon request from our investor relations department.

ITEM 7(a). Quantitative and Qualitative Disclosures about Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodically use derivative financial instruments such as commodity price hedging agreements.

The following analysis presents the effect earnings, cash flows and financial position as if the hypothetical changes in market risk factors occurred on December 31, 2002. Only the potential impacts of hypothetical assumptions are analyzed. This analysis does not consider other possible effects that could impact our business.

Interest rate risk. At December 31, 2002 the amount outstanding under our credit facility was $34.5 million. The weighted average interest rate for this facility was 3.76%. Assuming constant debt levels, earnings and cash flow impacts for the next twelve month period from December 31, 2002 due to a one percent change in interest rates would be approximately $345,000 before taxes.

Commodity price risk. Oil and gas commodity markets are influenced by global as well as regional supply and demand. Worldwide political events can also impact commodity prices. Pricing for oil and natural gas production has been volatile and unpredictable for many years. In accordance with our current lending facility and to hedge exposure to changing commodity prices we periodically entering into financial hedge contracts. Hedging may limit the Company's exposure to adverse price limits, hedging also limits the benefit of price increases and is subject to a number of risks, including credit risk of the counterparty to the hedge. For additional information, see note 1 to the Financial Statements.

The terms of our current credit facility require that not later than thirty days subsequent to the date of the new facility (April 12, 2002) not less than 50% of our projected monthly production be hedged at price levels and terms acceptable to the lender. During 2002, the Company made net payments to the counterparty of $305,425 under the hedge agreements in place. This amount is netted against our oil and gas revenue. We had no volumes subject to hedging agreements in 2001.

We account for our hedging activity pursuant to SFAS 133, accordingly we include the fair value of these hedges ($1,917,988 liability at December 31, 2002) on our balance sheet. "Fair value" represents the value computed by the counterparty using a financial modeling technique including a type of Black-Scholes method. As these contracts qualify and have been designated as cash flow hedges, we determine gains and losses on them resulting from market price changes at least quarterly and reflect them in accumulated other comprehensive income (loss) until the period in which the hedge is settled. At that time, the amount paid to or received from the counterparty is included in oil and gas revenue. We do not intend to terminate our current commodity hedges prior to their expiration date.

The hedges we had in place at December 31, 2002 were costless collars. The Company utilizes collars that establish a price between a floor and ceiling to hedge oil and natural gas prices. The table below sets forth our oil and natural gas collars in place at December 31, 2002.

Time Period	Per Day BBL/ MMBTU	Average Floor BBL/ MMBTU	Average Ceiling BBL/ MMBTU	Fair Value of Financial Instrument Asset/ (Liability) (thousands)
Oil				
05/01/02 04/30/03	1,100	$ 23.00	$ 27.10	$ (505)
Gas				
05/01/02 04/30/04	5,000	$ 3.00	$ 4.43	$ (1,330)
01/01/03 12/31/03	1,000	$ 3.50	$ 4.915	$ (83)

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ITEM 8. Financial Statements and Supplementary Data

Report of Independent Accountants

To the Stockholders and Board of
Directors of Equity Oil Company:

In our opinion, the financial statements as listed in Item 15 (a) of this Form 10-K, present fairly, in all material respects, the financial position of Equity Oil Company (the "Company") at December 31, 2002 and 2001, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America. 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 of these statements in accordance with auditing standards generally accepted in the United States of America, which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Salt Lake City, UT
March 13, 2003

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EQUITY OIL COMPANY

BALANCE SHEETS

DECEMBER 31, 2002 AND 2001

	2002	2001
ASSETS		
Currents assets:		
Cash and cash equivalents	**$ 1,348,024**	$ 960,970
Accounts receivable	**3,934,324**	2,442,141
Operator advances	**462,149**	487,855
Federal, state and foreign income taxes receivable	**1,054,927**	1,905,339
Deferred income taxes	**28,460**	25,843
Other current assets	**215,177**	31,794
Total current assets	**7,043,061**	5,853,942
Property and equipment, at cost (successful efforts method):		
Unproved oil and gas properties	**9,058,761**	3,229,500
Proved oil and gas properties:		
Developed leaseholds	**33,044,907**	10,968,348
Intangible drilling costs	**72,407,581**	69,784,350
Equipment	**31,332,238**	27,656,618
Other property and equipment	**1,331,490**	1,225,184
	147,174,977	112,864,000
Less accumulated depreciation, depletion and amortization	**(78,148,866)**	(70,693,316)
	69,026,111	42,170,684

		2002		2001
Other assets		**731,184**		284,709
Total assets	**$**	**76,800,356**	$	48,309,335
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current Liabilities:				
Accounts payable	**$**	**2,157,291**	$	2,801,183
Accrued liabilities		**406,681**		411,453
Federal, state and foreign income taxes payable		**170,399**		158,647
Fair value of financial instruments		**1,584,988**		
Total current liabilities		**4,319,359**		3,371,283
Fair value of financial instruments		**333,000**		
Revolving credit facility		**34,500,000**		5,500,000
Deferred income taxes		**4,398,319**		4,524,901
Total liabilities		**43,550,678**		13,396,184
Commitments (Note 6)				
Stockholders' equity:				
Common stock, $1 par value:				
Authorized: 25,000,000 shares				
Issued: 12,856,661 shares in 2002 and 12,851,661 shares in 2001		**12,856,661**		12,851,661
Paid in capital		**3,738,263**		3,735,763
Retained earnings		**19,855,106**		18,854,029
Accumulated other comprehensive loss		**(1,208,908)**		
		35,241,122		35,441,453
Less treasury stock at cost, 848,000 and 164,600 shares, respectively		**(1,991,444)**		(528,302)
		33,249,678		34,913,151
Total liabilities and stockholders equity	**$**	**76,800,356**	$	48,309,335

The accompanying notes are an integral part of the financial statements.

EQUITY OIL COMPANY

STATEMENT OF OPERATIONS

for the years ended December 31, 2002, 2001 and 2000

		2002		2001		2000
REVENUES						
Oil and gas sales	**$**	**24,343,277**	$	20,590,476	$	24,316,369

	2002	2001	2000
Other income	**309,282**	344,378	1,082,653
	24,652,559	20,934,854	25,399,022
EXPENSES			
Leasehold operating costs	**8,586,946**	6,720,610	6,726,769
Depreciation, depletion and amortization	**7,674,633**	4,197,543	3,808,777
Impairment of proved oil and gas properties	**53,990**	404,395	368,543
Equity loss in Symskaya Exploration, Inc.	**178,512**	161,494	174,432
Leasehold abandonments	**5,686**	3,198	14,820
3-D Seismic	**215,339**	697,676	979,028
Exploration	**908,379**	594,336	1,337,593
General and administrative	**2,409,304**	2,440,241	1,897,190
Production and exploration overhead	**1,424,116**	1,444,458	1,176,324
Interest	**1,176,375**	431,108	1,110,062
	22,633,280	17,095,059	17,593,538
Income before income taxes	**2,019,279**	3,839,795	7,805,484
Provision for income taxes	**1,018,202**	1,558,678	2,641,413
Net income	**$ 1,001,077**	$ 2,281,117	$ 5,164,071
Basic net income per common share	**$ .08**	$ .18	$ .41
Basic weighted average shares outstanding	**12,300,094**	12,680,068	12,646,101
Diluted net income per common share	**$ .08**	$ .18	$ .40
Diluted weighted average shares outstanding	**12,429,710**	12,946,226	12,875,750

The accompanying notes are an integral part of the financial statements.

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EQUITY OIL COMPANY

STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

for the years ended December 31, 2002, 2001 and 2000

	2002	2001	2000
Net income			
Other comprehensive loss:	**$ 1,001,077**	$ 2,281,117	$ 5,164,071
Unrealized losses of financial instruments, net of $709,080 tax benefit for 2002	**(1,208,908)**		
Comprehensive income (loss)	**$ (207,831)**	$ 2,281,117	$ 5,164,071

	2002	2001	2000

The accompanying notes are an integral part of the financial statements.

EQUITY OIL COMPANY
STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY
for the years ended December 31, 2002, 2001 and 2000

	Common Stock		Paid in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Treasury Stock		Total Stockholders Equity
	Shares	Amount				Shares	Amount	
Balance at January 1, 2000	12,808,040	$ 12,808,040	$ 3,719,743	$ 11,408,841	$	164,600	$ (528,302)	$ 27,408,322
Net income				5,164,071				5,164,071
Common stock issued on exercise of stock options	11,172	11,172	(3,731)					7,441
Income tax benefit from exercise of stock options			3,853					3,853
Balance at December 31, 2000	12,819,212	12,819,212	3,719,865	16,572,912		164,600	(528,302)	32,583,687
Net income				2,281,117				2,281,117
Common stock issued on exercise of stock options	32,449	32,449	(19,347)					13,102
Income tax benefit from exercise of stock options			35,245					35,245
Balance at December 31, 2001	12,851,661	12,851,661	3,735,763	18,854,029		164,600	(528,302)	34,913,151
Net income				1,001,077				1,001,077
Other comprehensive loss					(1,208,908)			(1,208,908)
Common stock issued on exercise of stock options	5,000	5,000	2,500					7,500
Treasury stock purchase						683,400	(1,463,142)	(1,463,142)
Balance at December 31, 2002	12,856,661	$ 12,856,661	$ 3,738,263	$ 19,855,106	$ (1,208,908)	848,000	$ (1,991,444)	$ 33,249,678

The accompanying notes are an integral part of the financial statements.

EQUITY OIL COMPANY

STATEMENTS OF CASH FLOWS

for the years ended December 31, 2002, 2001 and 2000

	2002	2001	2000
Cash flows from operating activities:			
Net income	**$ 1,001,077**	$ 2,281,117	$ 5,164,071
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**7,674,633**	4,197,543	3,808,777
Impairment of proved oil and gas properties	**53,990**	404,395	368,543
Equity loss in Symskaya Exploration, Inc.	**178,512**	161,494	174,432
Gain (loss) on sale of oil and gas properties	**17,791**	(81,824)	(482,191)
Change in other assets	**7,633**	82,228	94,619
Deferred income tax expense	**579,881**	990,379	1,860,663
Increase (decrease) from changes in:			
Accounts receivable and operator advances	**(1,466,477)**	2,541,941	(2,089,576)
Other current assets	**(183,383)**	26,873	218,928
Accounts payable and accrued liabilities	**833,492**	(762,534)	773,630
Income taxes payable/receivable	**862,164**	(2,236,392)	428,016
Net cash provided by operating activities	**9,559,313**	7,605,220	10,319,912
Cash flows from investing activities:			
Advances to Symskaya Exploration, Inc.	**(178,512)**	(161,494)	(174,432)
Capital expenditures	**(35,909,432)**	(5,871,044)	(3,145,188)
Proceeds from sale of oil and gas properties	**18,000**	184,638	702,349
Net cash used in investing activities	**(36,069,944)**	(5,847,900)	(2,617,271)
Cash flows from financing activities:			
Payments on revolving credit facility	**(8,000,000)**	(3,000,000)	(6,500,000)
Payment of revolving credit facility fees	**(646,673)**		(26,136)
Borrowings under revolving credit facility	**37,000,000**		
Treasury stock purchase	**(1,463,142)**		
Proceeds from stock option exercises	**7,500**	13,102	7,441
Net cash provided by (used in) financing activities	**26,897,685**	(2,986,898)	(6,518,695)
Net increase (decrease) in cash	**387,054**	(1,229,578)	1,183,946
Cash and cash equivalents at beginning of year	**960,970**	2,190,548	1,006,602
Cash and cash equivalents at end of year	**$ 1,348,024**	$ 960,970	$ 2,190,548
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Income taxes	**$ 326,458**	$ 2,656,395	$ 334,796
Interest	**$ 1,176,375**	$ 431,108	$ 1,110,062
Supplemental disclosures on non-cash investing activities:			
	$	$ 1,482,156	$

	2002	2001	2000
Property and equipment additions included in accounts payable			

The accompanying notes are an integral part of the financial statements.

EQUITY OIL COMPANY

NOTES TO FINANCIAL STATEMENTS

1. Significant Accounting Policies:

A. *The Company:*

Equity Oil Company ("Equity" or "the Company") is a Colorado corporation engaged in oil and gas exploration, development and production in the United States, and Canada.

B. *Cash and Cash Equivalents:*

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

C. *Accounting for Oil and Gas Operations:*

The Company reports using the "successful efforts" method of accounting for oil and gas operations. The use of this method results in capitalization of those costs identified with the acquisition, exploration and development of properties that produce revenue or, if in the development stage, are anticipated to produce future revenue. Costs of unsuccessful exploration efforts are expensed in the period in which it is determined that such costs are not recoverable through future revenues. Exploratory geological and geophysical costs are expensed as incurred. The costs of development wells are capitalized whether productive or nonproductive.

The Company annually assesses undeveloped oil and gas properties for impairment. Any impairment recorded represents management's estimate of the decline in realizable value experienced during the year. The unamortized costs of proved properties which management determines are not recoverable are written off in the period such determination is made. The net capitalized costs of proved oil and gas properties are measured for impairment based on a comparison of the expected undiscounted future net revenues from each property or field with the related net capitalized costs at the end of each period. When the net capitalized costs exceed the undiscounted future net revenues, the carrying value of the property is written down to fair value, which is determined using discounted future net revenues from the field. Reserve categories used in the impairment analysis considered all categories of proven reserves and probable and possible reserves, which are risk-adjusted based on our drilling plans and history of successfully developing those types of reserves.

The provision for depreciation, depletion and amortization (DD&A) of proved oil and gas properties is computed using the unit-of-production method, based on proved oil and gas reserves.

Revenues associated with oil and gas sales are recorded when the rights and responsibilities of ownership passes and are net of royalties.

D. *Concentration of Credit Risk:*

Substantially all of the Company's accounts receivable are within the oil and gas industry, primarily from purchasers of oil and gas (see Note 5). Although diversified within many companies, collectibility is dependent upon the general economic conditions of the industry. The receivables are not collateralized and, to date, the Company has experienced minimal bad debts. The majority of the Company's cash and cash equivalents is held by one financial institution located in Salt Lake City, Utah, and by one financial institution in Calgary, Alberta.

E. *Equipment:*

The provision for depreciation of equipment (other than oil and gas equipment) is based on the straight-line method using asset lives as follows:

Office equipment	10 years
Automobiles	3 years

When equipment is retired or otherwise disposed of, the cost and accumulated depreciation are removed from the accounts and any resulting gain or loss is included in the statement of operations.

F. *Foreign Operations:*

Operations and investments in Canada have been translated into U.S. dollar equivalents at the average rate of exchange in effect at the transaction date. Foreign currency translation gains or losses during 2002, 2001 and 2000 were not material.

G. *Net Income Per Common Share:*

Basic earnings per share is computed by dividing the net income by the weighted average number of common shares outstanding. Diluted earnings per share is computed by dividing the net income by the sum of the weighted average number of common shares and the effect of dilutive unexercised stock options. Dilutive options to purchase approximately 129,600 shares of common stock at prices of $1.06 to $1.78 per share, 266,200 shares of common stock at prices of $1.06 to $2.50 per share and 536,500 shares of common stock at prices of $1.06 to $1.71 per share were outstanding at December 31, 2002, December 31, 2001 and December 31, 2000, respectively, and were included in the computation of diluted net income per share. Options to purchase 1,695,200, 1,391,600, and 1,052,000 shares of common stock at prices ranging from $2.50 to $5.125 per share were outstanding at December 31, 2002, 2001 and 2000, respectively, but were not included in the computation of diluted earnings per share because the effect would have been antidilutive.

H. *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 assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Significant estimates with regard to these financial statements include the estimates of proved oil and gas reserve volumes and future dismantlement and abandonment costs used in determining DD&A and impairment provisions.

I. *Derivative Instruments and Hedging Activities*

The Company periodically enters into oil and gas financial instruments in accordance with its bank credit facility and to manage its exposure to oil and gas price volatility. The instruments are

usually placed with counterparties that the Company believes are minimal credit risks. It is the Company's policy to only enter into derivative contracts with investment grade rated counterparties deemed by management to be competent and competitive market makers. The oil and gas reference prices upon which the price hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by the Company.

The financial instruments are accounted for in accordance with Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities", which established new accounting and reporting requirements for derivative instruments and hedging activities effective January 1, 2001. The adoption of SFAS No. 133 had no financial statement impact at the date of adoption. SFAS No. 133, as amended by SFAS No. 138, requires that all derivative instruments subject to the requirements of the statement be measured at fair value and recognized as assets or liabilities in the balance sheet. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation is established at the inception of a derivative. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of SFAS No. 133, changes in fair value, to the extent effective, are recognized in other comprehensive income (loss) until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value of a derivative resulting from ineffectiveness or an excluded component of the gain/loss is recognized immediately in revenue in the statement of operations.

The terms of our current credit facility require that not later than thirty days subsequent to the date of the new facility (April 12, 2002) not less than 50% of our projected monthly production be hedged at price levels and terms acceptable to the lender. As of December 31, 2002, the Company had commodity price hedges in place for 1,100 barrels of oil per day thru April 30, 2003 and 6,000 MMBTU of natural gas per day (5,000 MMBTU per day thru April 30, 2004 and an additional 1,000 MMBTU per day thru December 31, 2003) under costless collars. The oil hedge has a floor of $23.00 and a ceiling of $27.10 and the gas hedges range from $3.00 per MMBTU to $4.92 per MMBTU. The settlement price of each of the contracts for months during the year resulted in cash payments of $305,425 from the Company to the counterparty. The fair value of the hedges at December 31, 2002, as computed by the counterparty, was ($1,917,988). This amount is shown on the balance sheet as fair value of financial instruments. The Company does not intend to terminate the current commodity hedges prior to their expiration date.

Under the terms of its prior revolving credit facility, the Company was required to hedge at least 50%, but not more than 75%, of its daily oil production at a price not lower than the lowest price used in the bank's price deck, for a period between 12 and 18 months commencing with the effective date of the facility, which was September 9, 1999. The Company had 120 days after the closing date in September 1999 to have the hedge or hedges in place. The Company entered into one collar agreement for 12 months effective October 1, 1999, covering 400 barrels per day with a floor at $18.00 per barrel and a ceiling at $25.30 per barrel. The Company entered into a second collar agreement for 12 months effective January 1, 2000, covering 500 barrels per day with a floor at $18.00 per barrel and a ceiling at $27.22 per barrel. As a result of these hedges, revenues were reduced by $1,048,018 in 2000. No hedging transactions occurred in 2001.

J. *Stock Based Compensation Plans*

At December 31, 2002, the Company had one stock-based compensation plan. (See note 5.) The Company applies APB Opinion No. 25 and related interpretations in accounting for this plan. Accordingly, no compensation cost has been recognized for options granted to employees under its fixed stock option plan.

On December 31, 2002, the Financial Accounting Standards Board ("FASB") issued SFAS No. 148, "Accounting for Stock Based Compensation Transition and Disclosure," which amends SFAS No. 123. SFAS No. 148 requires more prominent and frequent disclosures about the effects of stock-based compensation, which the Company has adopted for the period ending December 31, 2002. We willl continue to account for our stock based compensation according to the provisions of APB Opinion No. 25.

Had compensation cost for the Company's stock options been recognized based upon the estimated fair value on the grant date under the fair value methodology prescribed by SFAS No. 123, as amended by SFAS No. 148, the Company's net earnings and earnings per share would have been as follows:

		2002	2001	2000
Net Income, as reported		$ 1,001,077	$ 2,281,117	$ 5,164,071
Less: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects		(167,228)	(230,736)	(197,785)
Pro forma net income		$ 833,849	$ 2,050,381	$ 4,966,286
Net Income per share				
Basic	As reported	$ .08	$ .18	$ .41
	Pro forma	$ .07	$ .16	$ .39

		2002	2001	2000
Diluted	As reported	$ .08	$ .18	$ .40
	Pro forma	$ .07	$ .16	$ .39

2. Impairment of Proved Oil and Gas Properties:

The Company recorded non-cash impairment charges of $53,990, $404,395 and $368,543 for 2002, 2001 and 2000, respectively related to oil and gas properties.

3. Yolo County California Asset Acquisition:

During the second quarter of 2002, the Company purchased interests in 27 producing and 16 non-producing gas wells and associated undeveloped leaseholds located in Yolo County, California. This Sacramento Basin acquisition was closed on April 12, 2002 with an effective date of January 1, 2002. The interests acquired are working interests and the Company assumed operations of the properties on May 1, 2002. The total consideration for the properties was $32.0 million. Net proceeds from the effective date to the date of closing were netted against the purchase price and thus approximately $30.0 million was paid at closing.

The following unaudited pro forma financial information for the years ended December 31, 2002 and 2001 assumes the Yolo County asset acquisition occurred as of the beginning of the respective years. The pro forma results for 2002 and 2001 combine the Company's historical results for the year ended December 31, 2002 and 2001 with the historical results of the acquired assets for the same periods, after giving effect to certain adjustments, including additional DD&A and interest expense associated with the acquired assets. The pro forma results have been prepared for illustrative purposes only. Such information does not purport to be indicative of the results of operations which actually would have resulted had the acquisition occurred on the dates indicated, nor is it indicative of the results that may be expected in future periods.

	2002	2001
Revenues	$ 27,242,068	$ 58,685,409
Less:		
Direct operating expenses	9,040,391	8,838,757
Depreciation, depletion and amortization	8,700,033	8,299,143
Interest expense	1,464,375	1,583,108
Income taxes	2,971,378	14,774,839
Net Income	$ 5,065,891	$ 25,189,562
Basic net income per common share	$ 0.41	$ 1.99
Basic weighted average shares outstanding	12,300,094	12,680,068
Diluted net income per common share	$ 0.41	$ 1.95
Diluted weighted average shares outstanding	12,429,710	12,946,226

4. Income Taxes:

The Company accounts for income taxes in accordance with SFAS No. 109, *Accounting for Income Taxes*. Deferred income taxes are provided using enacted tax rates applied to the difference between the tax basis of an asset or liability and its reported amount in the financial statements that will result in taxable or deductible amounts in future years when the reported amount of the asset or liability is recovered or settled, respectively.

	2002	2001	2000
Earnings before Federal, State and non-U.S. income taxes			
United States	$ 1,529,985	$ 2,793,513	$ 6,426,362
Non-U.S.	489,294	1,046,282	1,379,122

	2002	2001	2000
Total	$ 2,019,279	$ 3,839,795	$ 7,805,484

The provision for income taxes consists of the following:

	2002	2001	2000
Currently payable:			
U.S. income taxes (including alternative minimum tax)	$	$	$ 14,924
State income taxes	2,500	2,500	158,582
Canadian income taxes	431,224	407,343	605,725
Changes in prior years' taxes	4,597	158,456	1,519
Deferred tax expense	579,881	990,379	1,860,663
	$ 1,018,202	$ 1,558,678	$ 2,641,413

The components of the net deferred tax liability as of December 31, 2002 and 2001 consist of the following:

	2002	2001
Deferred tax assets:		
AMT credit carryforward	$ 445,563	$ 445,563
State income taxes	924	924
Deferred compensation	27,535	24,919
Geological and geophysical costs	516,709	489,709
Accrued interest		396,330
Foreign tax credit carryforward	104,486	161,633
Equity loss and impairment of investment in Symskaya Exploration, Inc.		643,470
Fair value of financial instruments	709,080	
Statutory depletion carryforward	428,780	300,602
Net operating loss carryforward	1,468,779	1,217,482
	3,701,856	3,680,632
Valuation allowance	(104,486)	(161,633)
Total deferred tax asset	3,597,370	3,518,999
Deferred tax liabilities:		
Property and equipment	7,909,584	7,987,180
Other assets	57,645	30,877
Total deferred tax liability	7,967,229	8,018,057
Net deferred tax liability	$ 4,369,859	$ 4,499,058

The net deferred tax liability as of December 31, 2002 and 2001 is reflected in the balance sheet as follows:

Current deferred tax asset	$ (28,460)	$ (25,843)
Long-term deferred tax liability	4,398,319	4,524,901
	$ 4,369,859	$ 4,499,058

The provision for income taxes differs from the amount that would be provided by applying the statutory U.S. Federal income tax rate to income before income taxes for the following reasons:

	2002	2001	2000
Federal statutory tax expense	$ 686,555	$ 1,305,530	$ 2,653,323
Increase (reduction) in taxes resulting from:			
State taxes (net of federal benefit)	44,558	88,927	211,225
Canadian taxes (net of foreign tax credits)	343,784	382,071	136,988
Excess allowable percentage depletion	(107,899)	(253,978)	(319,803)
Investment tax and other credits			(31,000)
Changes in prior years' taxes and other	51,204	36,128	(9,320)
Provision for income taxes	$ 1,018,202	$ 1,558,678	$ 2,641,413

At December 31, 2002, the Company had approximately $446,000 of alternative minimum tax credit carryforwards which can be carried forward indefinitely, and a net operating loss carryforward of approximately $3,973,000 which will begin to expire in 2021.

5. Stock-Based Compensation Plan:

Under the 2000 Equity Oil Company Incentive Stock Option Plan, the Company may grant options to its employees, directors and consultants to purchase up to 1.2 million shares of common stock. The Company also has unexercised options outstanding under previous stock option plans. The options may take the form of incentive stock options or nonstatutory stock options. The exercise price of each option equals the market price of the Company's stock on the date of grant, and an option's maximum term is 10 years. Options are granted from time to time at the discretion of the Board of Directors, and vest over periods of one to five years from the grant date.

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions used for grants in 2002, 2001

and 2000 respectively: expected volatility of 55, 57 and 95 percent, risk-free interest rates of 4.1, 4.8 and 6.8 percent; expected life of 5 to 7 years and dividend yield of zero for all three years.

	2002		2001		2000	
Fixed Options	Shares (000)	Weighted-Average Exercise Price	Shares (000)	Weighted-Average Exercise Price	Shares (000)	Weighted-Average Exercise Price
Outstanding at beginning of year	1,658	$ 3.25	1,589	$ 3.14	1,434	$ 3.45
Granted	365	1.88	296	3.46	219	1.55
Exercised	(5)	1.50	(92)	1.27	(15)	1.06
Forfeited/Expired	(193)	3.98	(135)	3.82	(49)	5.66
Outstanding at end of year	1,825	2.91	1,658	3.25	1,589	3.14

	2002	2001	2000
Options exercisable at year-end	1,195	1,187	1,149
Weighted-average fair value of options granted during the year	$ 1.88	$ 1.83	$ 1.18

The following table summarizes information about fixed stock options outstanding at December 31, 2002:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/02	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable at 12/31/02	Weighted-Average Exercise Price
$ 1.063-$1.063	209,800	6.25 years	$ 1.063	150,400	$ 1.063
$ 1.500-$2.500	678,000	7.84	1.897	262,200	1.946
$ 3.200-$3.200	100,000	8.42	3.200	20,000	3.200
$ 3.450-$3.625	433,500	4.92	3.589	359,100	3.581
$ 3.875-$4.250	136,000	1.01	4.250	136,000	4.250
$ 5.000-$5.125	267,500	2.27	5.078	267,500	5.078
	1,824,800	5.67	$ 2.916	1,195,200	$ 3.311

6. Geographic Segment Information:

The Company follows SFAS No. 131, *Disclosure about Segments of an Enterprise and Related Information*. The Company operates in the exploration and production segment of the oil and gas industry. The Company's operations are located in the following geographical areas.

	Revenues for the years ended December 31,			Long-lived Assets as of December 31,		
	2002	2001	2000	2002	2001	2000
United States	$ 22,089,049	$ 18,250,919	$ 21,746,294	$ 135,744,700	$ 101,668,080	$ 96,017,461
Canada	2,254,228	2,339,557	2,570,075	11,430,277	11,195,920	10,014,344
Total	$ 24,343,277	$ 20,590,476	$ 24,316,369	$ 147,174,977	$ 112,864,000	$ 106,031,805

Revenue from a major U.S. oil company accounted for approximately 41 percent of total revenues in 2002, 49 percent of total revenues in 2001 and 47 percent of total revenues in 2000. Another major

purchaser of natural gas accounted for approximately 33 percent of total revenues in 2002. The Company believes these purchasers could be replaced, if necessary, without a loss in revenue.

7. Symskaya Exploration:

Symskaya Exploration, Incorporated, a company in the development stage and a Texas corporation (Symskaya), was formed on November 25, 1991, and has been engaged in oil and gas exploration in Russia. Symskaya holds a Combined License (License) which grants it the exclusive right to explore, develop and produce hydrocarbons on a contract area totaling approximately 1,100,000 acres in the Yenisysk District of the Krasnoyarsk Krai in the Russian Federation. The License has a primary term of 25 years from November 15, 1993.

Minimum expenditures required under the License and PSA totaled $12,000,000 during the first five years of the License term, which began on November 15, 1993. Symskaya has satisfied all of the minimum expenditures in the time required under the license.

Symskaya is owned 50% each by Equity Oil Company (Equity) and Leucadia National Corporation, (Leucadia). The Company's President serves on Leucadia's Board of Directors. The Company's investment in Symskaya is being accounted for using the equity method of accounting.

The Company's 50% share of Symskaya's net loss was $178,512, $161,494 and $174,432 in 2002, 2001 and 2000, respectively. All advances to Symskaya are charged to expense in the period made.

In 2001, Symskaya, in an effort to make the entity more attractive to outside investors, sought a debt restructuring with its creditors. They asked that the debt excluding the original loans and associated accrued interest be formally forgiven. The creditors agreed to this restructuring plan and Equity forgave $8,419,792 of debt and associated accrued interest. This entire amount had been written off for financial statement purposes in previous years.

At the end of 2002, Symskaya determined to cease all operations in Russia due to the inability to attract a partner who was willing to finance the future development of the license area. Any costs incurred to 2003 will be costs associated with winding down activities associated with the project.

8. Note Payable:

On April 12, 2002 the Company entered into a new $75 million credit agreement (the "Facility") arranged by Bank One, NA. The new Facility replaced the prior $50 million revolving credit facility and was utilized to acquire certain assets in Yolo County, California. Semi-annually a borrowing base review of the value of the Company's oil and gas assets takes place to determine the lenders' borrowing base commitment. As of December 31, 2002 the commitment was $38 million. The terms of the Facility call for interest payments only, at the lower of prime or LIBOR plus 2.25%, until April 12, 2005, at which time the principal amount becomes due.

An unused commitment fee of $^{1}/_{2}$% will be charged annually to the Company based on the average daily unused portion of the Facility. The Facility is collateralized by essentially all oil and gas assets of the Company. As of December 31, 2002, the outstanding balance under the Facility was $34,500,000 at a weighted average interest rate of 3.76%. The weighted average interest rate for 2001 was 3.71%.

8. Note Payable: (Continued)

The Facility contains provisions relating to maintenance of certain financial ratios, as well as restrictions governing its use. Under covenants contained in the Facility, the Company has agreed, among other things, not to advance any proceeds from the Facility to Symskaya and not to merge with or acquire any other company without the prior approval of the bank. As of December 31, 2002, the Company was in compliance with all covenants in the Facility. Facility fees, which are reflected as other assets in the accompanying balance sheet, are being amortized over the term of the agreement.

9. Quarterly Financial Data (Unaudited):

Quarterly financial information for the years ended December 31, 2002 and 2001 is as follows:

2002 Quarter Ended	December 31	September 30	June 30	March 31
Net revenues	$ 7,276,153	$ 6,257,848	$ 7,143,550	$ 3,665,726
Gross margin	2,236,793	2,066,874	2,756,584	1,021,447
Net income	97,140	912	861,189	41,836
Basic income per common share	$ .01	$ .00	$ .07	$ .00
Diluted income per common share	$ .01	$ .00	$ .07	$ .00

2002 Quarter Ended	December 31	September 30	June 30	March 31
Net revenues	$ 3,342,872	$ 3,797,827	$ 6,391,517	$ 7,058,260

2002 Quarter Ended	December 31	September 30	June 30	March 31
Gross margin	858,260	1,020,693	3,460,146	4,333,224
Net income (loss)	(972,891)	(125,535)	1,468,685	1,910,858
Basic income (loss) per common share	$ (.08)	$ (.01)	$ .12	$ .15
Diluted income (loss) per common share	$ (.08)	$ (.01)	$ .12	$ .15

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10. Disclosures About Oil and Gas Producing Activities:

Capitalized Costs:

	United States	Canada	Total
2002:			
Unproved oil and gas properties	$ 9,028,723	$ 30,038	$ 9,058,761
Proved oil and gas properties	125,384,487	11,400,239	136,784,726
	134,413,210	11,430,277	145,843,487
Accumulated depreciation, depletion and amortization	(69,588,177)	(7,620,474)	(77,208,651)
Net capitalized costs	$ 64,825,033	$ 3,809,803	$ 68,634,836
2001:			
Unproved oil and gas properties	$ 3,199,462	$ 30,038	$ 3,229,500
Proved oil and gas properties	97,243,433	11,165,883	108,409,316
	100,442,895	11,195,921	111,638,816
Accumulated depreciation, depletion and amortization	(62,619,408)	(7,290,921)	(69,910,329)
Net capitalized costs	$ 37,823,487	$ 3,905,000	$ 41,728,487
2000:			
Unproved oil and gas properties	$ 2,571,276	$ 30,038	$ 2,601,314
Proved oil and gas properties	92,334,569	9,984,303	102,318,872
	94,905,845	10,014,341	104,920,186
Accumulated depreciation, depletion and amortization	(58,857,043)	(7,007,271)	(65,864,314)
Net capitalized costs	$ 36,048,802	$ 3,007,070	$ 39,055,872

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Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities:

	United States	Canada	Russia	Total
2002:				
Acquisition of properties:				

	United States	Canada	Russia	Total
Proved	$ 24,510,503			$ 24,510,503
Unproved	5,861,466			5,861,466
Exploration costs	1,424,909	$ 16,165		1,441,074
Development costs	4,725,113	300,543		5,025,656
	$ 36,521,991	$ 316,708	$	$ 36,838,699
Symskaya, equity method			$ 178,512	$ 178,512
2001:				
Acquisition of properties:				
Proved	$ 748,094			$ 748,094
Unproved	809,212			809,212
Exploration costs	1,540,338	$ 19,263		1,559,601
Development costs	5,431,020	1,428,177		6,859,197
	$ 8,528,664	$ 1,447,440	$	$ 9,976,104
Symskaya, equity method			$ 161,494	$ 161,494
2000:				
Acquisition of properties:				
Proved	$ 20,500			$ 20,500
Unproved	519,660			519,660
Exploration costs	3,447,209	$ 17,924		3,465,133
Development costs	1,793,824	679,736		2,473,560
	$ 5,781,193	$ 697,660	$	$ 6,478,853
Symskaya, equity method			$ 174,432	$ 174,432

Results of Operations (Unaudited):

	United States	Canada	Russia	Total
2002:				
Oil and gas sales	$ 22,089,049	$ 2,254,228		$ 24,343,277
Lease operating costs	(7,760,913)	(826,033)		(8,586,946)
Exploration expenses	(2,540,915)	(12,605)		(2,553,520)
Depreciation, depletion and amortization	(7,345,080)	(329,553)		(7,674,633)
Impairment of proved oil and gas properties	(53,990)			(53,990)
Equity loss in Symskaya Exploration, Inc.			$ (178,512)	(178,512)

	United States	Canada	Russia	Total
	4,388,151	1,086,037	(178,512)	5,295,676
Imputed income tax benefit (expense)	(1,210,630)	(483,286)	66,942	(1,626,974)
Results of operations from producing activities	$ 3,177,521	$ 602,751	$ (111,570)	$ 3,668,702
2001:				
Oil and gas sales	$ 18,250,919	$ 2,339,557		$ 20,590,476
Lease operating costs	(5,956,537)	(764,073)		(6,720,610)
Exploration expenses	(2,723,710)	(15,958)		(2,739,668)
Depreciation, depletion and amortization	(3,913,893)	(283,650)		(4,197,543)
Impairment of proved oil and gas properties	(404,395)			(404,395)
Equity loss in Symskaya Exploration, Inc.			$ (161,494)	(161,494)
	5,252,384	1,275,876	(161,494)	6,366,766
Imputed income tax benefit (expense)	(1,664,731)	(567,765)	60,560	(2,171,936)
Results of operations from producing activities	$ 3,587,653	$ 708,111	$ (100,934)	$ 4,194,830
2000:				
Oil and gas sales	$ 21,746,294	$ 2,570,075		$ 24,316,369
Lease operating costs	(6,122,894)	(603,875)		(6,726,769)
Exploration expenses	(3,493,390)	$ (14,374)		(3,507,764)
Depreciation, depletion and amortization	(3,684,117)	(124,661)		(3,808,778)
Impairment of proved oil and gas properties	(368,543)			(368,543)
Equity loss in Symskaya Exploration, Inc.			$ (174,432)	(174,432)
	8,077,350	1,827,165	(174,432)	9,730,083
Imputed income tax benefit (expense)	(2,604,092)	(344,352)	65,412	(2,883,032)
Results of operations from producing activities	$ 5,473,258	$ 1,482,813	$ (109,020)	$ 6,847,051

The imputed income tax benefit (expense) is hypothetical and determined without regard to the Company's deduction for general and administrative costs and interest expense.

10. Disclosures About Oil and Gas Producing Activities: (Continued)

Reserves and Future Net Cash Flows (Unaudited):

Estimates of reserve quantities and related future net cash flows are calculated using unescalated year-end oil and gas prices and operating costs, and may be subject to substantial fluctuations based on the prices in effect at the end of each year. Reserve revisions occur when the economic limit of a property is lengthened or shortened due to changes in commodity pricing. The following table sets forth the weighted average prices used in calculating estimated reserve quantities and future net cash flows at the end of 2002, 2001 and 2000:

	United States		Canada		Total	
	Oil	Gas	Oil	Gas	Oil	Gas

	United States		Canada		Total	
December 31, 2002	$ 27.64	$ 4.10	$ 23.34	$ 3.94	$ 27.01	$ 4.09
December 31, 2001	$ 16.84	$ 2.18	$ 12.21	$ 2.03	$ 16.03	$ 2.15
December 31, 2000	$ 24.41	$ 10.42	$ 19.40	$ 10.18	$ 23.78	$ 10.39

Estimates of Proved Oil and Gas Reserves (Unaudited):

The following tables present the Company's estimates of its proved oil and gas reserves. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and gas properties. Accordingly, the estimates are expected to change as future information becomes available. Reserve estimates are prepared by the Company and audited by the Company's independent petroleum reservoir engineers, Fred S. Reynolds and Associates, who have issued a report expressing their opinion that the reserve information in the following tables complies with the applicable rules promulgated by the Securities and Exchange Commission and the Financial Accounting Standards Board. The volumes presented on the following pages are in thousands of barrels for oil and thousands of mcf for gas.

Reserves and Future Net Cash Flows (Unaudited):

	United States		Canada		Total	
	Oil	Gas	Oil	Gas	Oil	Gas
December 31, 2002						
Proved developed and undeveloped reserves:						
Beginning of year	6,989	13,627	1,592	2,952	8,581	16,579
Revisions of previous estimates	1,017	(818)	88	97	1,105	(721)
Extensions and discoveries	367	67			367	67
Acquisition of minerals in place		24,861				** 24,861
Improved recovery	1,130				1,130	
Production	(535)	(3,941)	(99)	(257)	(634)	(4,198)
End of year	8,968	33,796	1,581	2,792	10,549	36,588
Proved developed reserves:						
Beginning of year	6,974	9,516	1,409	2,815	8,383	12,331
End of year	7,558	29,173	1,483	2,718	9,041	31,891
December 31, 2001:						
Proved developed and undeveloped reserves:						
Beginning of year	7,836	14,215	1,293	2,776	9,129	16,991
Revisions of previous estimates	(1,555)	(1,111)	167	159	(1,388)	(952)
Extensions and discoveries	134	1,413	216	305	350	1,718
Acquisition of minerals in place	265	318			265	318
Improved recovery	862				862	
Production	(553)	(1,208)	(84)	(288)	(637)	(1,496)
End of year	6,989	13,627	1,592	2,952	8,581	16,579
Proved developed reserves:						
Beginning of year	7,439	11,285	1,104	2,776	8,543	14,061
End of year	6,974	9,516	1,409	2,815	8,383	12,331

	United States		Canada		Total	
December 31, 2000:						
Proved developed and undeveloped reserves:						
Beginning of year	8,042	13,838	1,251	2,493	9,293	16,331
Revisions of previous estimates	450	1,014	(247)	265	203	1,279
Extensions and discoveries	154	819	349	223	503	1,042
Acquisition of minerals in place	46				46	
Sales of minerals in place	(440)				(440)	
Improved recovery	174		16		190	
Production	(590)	(1,456)	(76)	(205)	(666)	(1,661)