GULFWEST
ENERGY INC.
A Natural Resource Company

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ANNUAL REPORT AND 10-K
2003

GULFWEST ENERGY INC.

480 NORTH SAM HOUSTON PARKWAY EAST • SUITE 300 • HOUSTON, TEXAS 77060
281-820-1919 • FAX 281-260-8488

		2003		2002		2001
Proved reserves (SEC year-end prices)						
Oil (MBbls)		5,038		5,522		5,872
Natural Gas (MMcf)		32,660		34,159		39,258
Oil equivalent (MBOE)		10,481		11,215		12,415
Future net revenue from proved reserves (at year end prices):						
Undiscounted ($000)		205,866		179,401	$	98,026
Discounted at 10% ($000)		114,396		98,899	$	56,499
Production (net sales volume):						
Oil (MBbls)		221		278		294
Natural Gas (MMcf)		1,191		1,487		1,595
Oil equivalent (MBOE)		420		526		560
Average prices for the year:						
Oil ($/Bbl)	$	24.22	$	21.05	$	22.73
Natural Gas ($/Mcf)	$	4.60	$	3.09	$	3.60
Average prices at year end:						
Oil ($/Bbl)	$	29.51	$	28.72	$	17.67
Natural Gas ($/Mcf)	$	5.82	$	4.43	$	2.43
		(x1000)		(x1000)		(x1000)
Total revenues	$	11,010	$	10,840	$	12,991
Less operating and overhead expenses		7,790		7,214		7,047
Income from operations		3,220		3,626		5,944
Less interest income/expense		3,363		3,160		2,757
Income before non-cash and one-time items		(143)		466		3,187
Non-cash and one-time items		(3,144)		(4,968)		1,605
Income (loss) before income taxes and cumulative effect of change in accounting procedures		(3,287)		(4,502)		4,792
Income taxes		0		0		0
Cumulative effect of change in accounting procedures		263		0		(3,748)
Net income (loss)		(3,024)		(4,502)		1,044
Less dividends on preferred stock		(127)		(113)		(56)
Net income (loss) for common shareholders	$	(3,151)	$	(4,615)		988
Net income (loss) per common share (dollars)	$	(.17)	$	(.25)	$	.05
		(x1000)		(x1000)		(x1000)
Total assets	$	52,429	$	53,089	$	51,379
Long-term debt, including current portion		29,562		33,523		32,830
Stockholders' equity	$	5,825	$	7,824	$	12,345
Weighted average shares outstanding		18,493		18,493		18,464

Letter to the Shareholders of GulfWest Energy Inc. May 2004

Dear Fellow Shareholders,

As a part of our annual report, we have included a brief synopsis of last year as well as a few comments on our status and plans for 2004. Also included are a few tables and charts summarizing financial and operating data, and the table on the inside cover of the annual report provides an additional financial summary.

A Look Back at 2003

For GulfWest, the year 2003, was dominated by efforts to refinance our debt, to maintain operations in our oil and gas fields while waiting on the securing of development capital, and to negotiate with potential lenders and investors/financiers about the future value and production of the company and its assets and how to best finance the efforts to achieve those values.

Our oil and natural gas production was lower in 2003, as we had very little capital to develop our properties and hence, could not maintain our production. In addition, the majority of our excess cashflow funded debt service and refinancing costs. Despite these events, our oil and gas fields still generated $7 million of field level cashflow, and we were able to hold our asset base in tact. After an oil and gas hedge loss of approximately $1.5 million and overhead of $1.5 million, our corporate EBITDA was $4 million. The majority of this was used to service debt ($3 million) and pay financing costs/penalty interest ($0.9 million).

Our proved oil and gas reserves total 5 million barrels of oil and 32 bcf of natural gas at the end of 2003. This is approximately 6% lower than a year earlier, due to lower proved producing reserves as a result of lower production, and the reduction of proved undeveloped reserves in fields where development has been delayed well in to the future. We still have approximately 40% of our reserves booked as behind pipe reserves (also referred to as proved developed non-producing, or pdnp reserves), and this represents a significant amount of production waiting on workovers, recompletions and facility enhancements. Hence, the potential for increased production in our asset base remains in place.

Our split between oil and natural gas remains approximately 50%. On a boe basis, our production was 53% crude oil and 47% natural gas; on a reserve basis, 53% of our reserves are natural gas and 47% are crude oil.

Moving Ahead – 2004 Plans

As 2004 began, we found ourselves continuing with efforts to refinance our largest debt. This effort was finally concluded in April when we closed a new bridge loan facility for $18 million, and we raised $4 million of new equity. While the effort took much longer than we had anticipated, the result is a very significant change to our balance sheet and financial make-up.

As reported in our first quarter 2004 quarterly report, we were able to secure a bridge loan with a new energy lender, who in essence, bought our existing, largest debt of $27.6 million for $15.7 million. This resulted in a forgiveness of debt of $11.9 million, and it reduced the overall debt of the company by approximately 26%. In addition, the new loan is an 18-month bridge loan, interest only, and we will have $3.5 million of capital available this year, to develop these oil and gas properties through workovers and facility enhancement activities. Hence, this refinancing allowed us to reduce debt, bring our trade payables current, and kick-off our development program.

As we go forward in 2004, the new financial challenge facing the company is how to best re-capitalize the company, simplify our debt structure and fund our additional development projects. While the April refinancing has provided us time to consider our alternatives, the new bridge loan has a high interest rate of 11% over the prime rate, and after 9 months this increases. Hence we have begun the process of considering various alternatives to re-capitalize the company, and are working to consummate a transaction in the next 9 months. As a first step in this effort, the board of directors elected Mr. John Loehr, a director of the company for 12 years, as chief executive officer of the company. John will step in to focus on the financial aspects of the company and lead the effort of considering various re-capitalization alternatives. I will continue in leading the development and operational activities, as well as providing input on our asset values, business alternatives, and areas for future growth.

In summary, in 2004, we will be proceeding to enhance shareholder value by implementing our workover program, and also through further re-capitalization efforts. Our goal is to simplify the financial structure of the company, build on the production and asset base we have in place, and consider a wide range of alternatives for growing the company. Unlike in 2003, as we proceed with financing alternatives in 2004, we find ourselves able to implement near term development projects, we have significantly lower debt, and we are in a much improved industry environment.

Please watch for announcements and updates on our website at gulfwestenergy.com. You may contact John Loehr or myself for questions or comments.

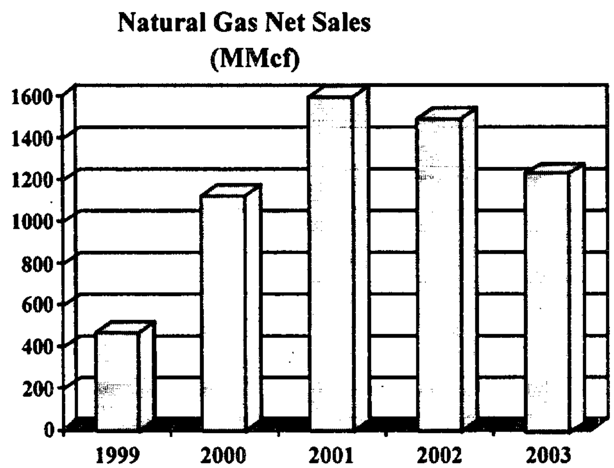
Sincerely,

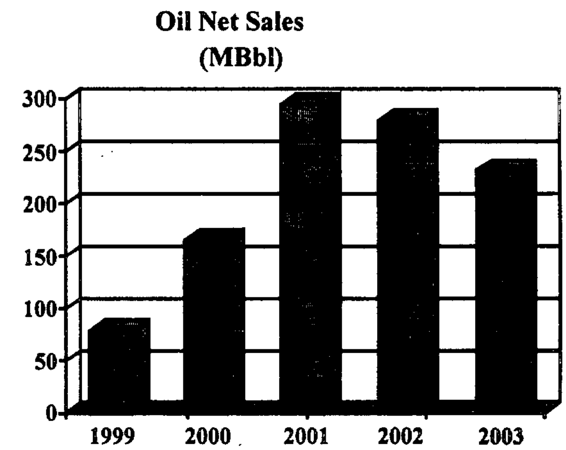
Thomas Kaetzer

Thomas Kaetzer
President/COO

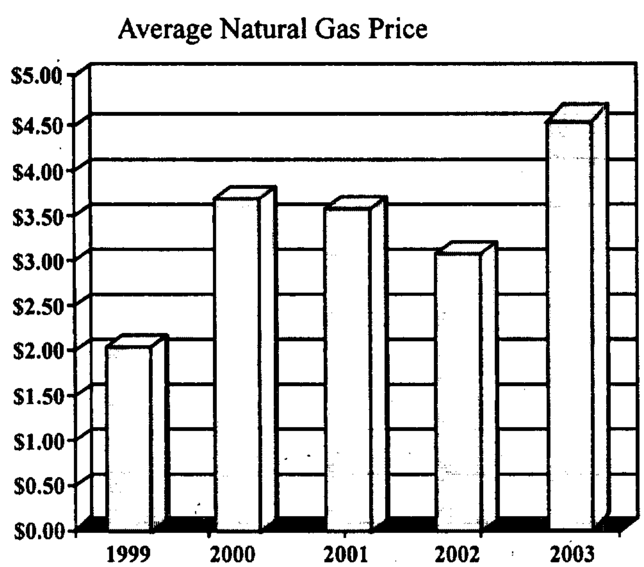
Oil and Natural Gas Annual Sales Volumes

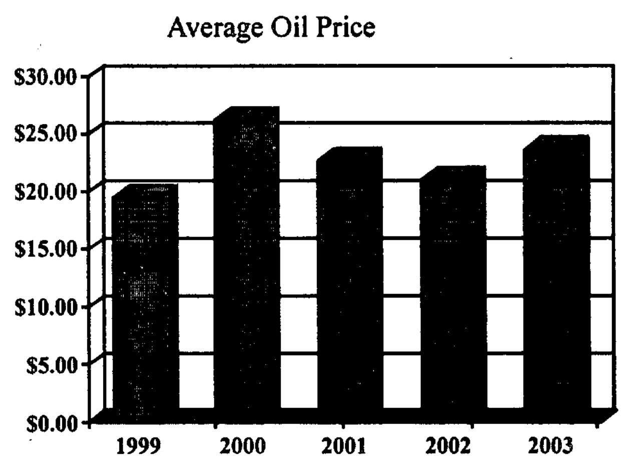
Production in 2003 was lower due to the lack of capital and excess cash flow available to fund development projects.



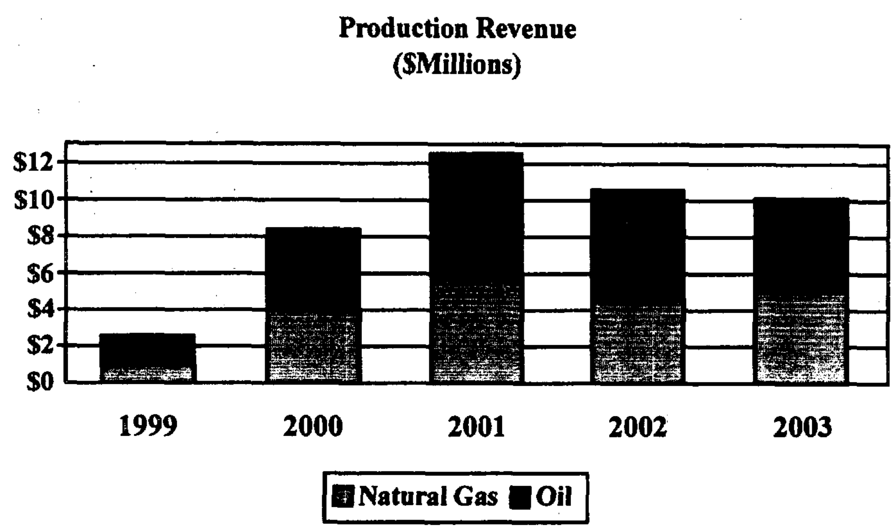


Oil and Natural Gas Prices



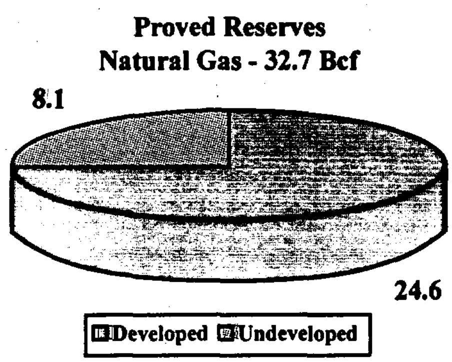


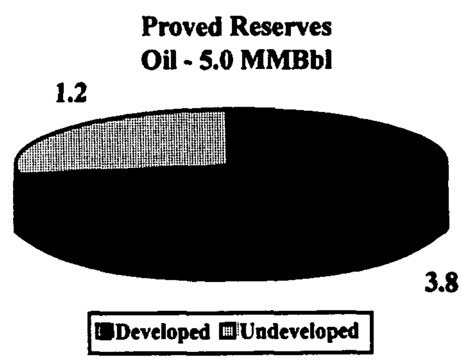
Net Oil and Natural Gas Revenue



Oil and Gas Reserves

At the end of 2003, in addition to our proved developed producing (PDP) reserves, we had significant proved developed non-producing (PDNP) and proved undeveloped (PUD) reserves, indicating significant growth potential within our existing asset base. These assets and their development potential are providing us the ability to refinance and they are the basis for the future growth of the company





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

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2003

or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ____ to ____.
Commission file number 1-12108.

GulfWest Energy Inc.

(Exact name of registrant as specified in its charter)

Texas	**87-0444770**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
480 N. Sam Houston Parkway East, Suite 300 Houston, Texas	**77060**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (281) 820-1919.

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

Title of Each Class

Class A Common Stock, par value of $.001 per share

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

Title of Each Class

Class A Common Stock, par value of $.001 per share

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 X No ___

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12-b2 of the Act).

Yes ___ No X

The aggregate market value of voting stock of the Registrant held by non-affiliates, computed by reference to the closing price of such stock on June 30, 2003, was approximately $3,507,271. For purposes of this computation, all executive officers, directors and ten percent (10%) beneficial owners of the Registrant are deemed to be affiliates. Such determination should not be deemed an admission that such executive officers, directors and ten percent (10%) beneficial owners are affiliates.

Indicate the number of shares outstanding of each of the Registrant's classes of common stock: Class A Common Stock $.001 par value: 18,492,541 shares on March 29, 2004.

DOCUMENTS INCORPORATED BY REFERENCE:

The registrant's definitive Proxy Statement pertaining to the 2003 Annual Meeting of Shareholders (the "Proxy Statement") and filed or to be filed not later than 120 days after the end of the fiscal year pursuant to Regulation 14A is incorporated herein by reference into Part III.

PART I

ITEM 1. Business.

Our Business.

We are primarily engaged in the acquisition, development, exploitation and production of crude oil and natural gas. Our focus is on increasing production from our existing properties through further exploitation, development and exploration, and on acquiring additional interests in crude oil and natural gas properties.

Since we made our first significant acquisition in 1993, we have substantially increased our ownership in *producing properties* and the value of our crude oil and natural gas reserves through a combination of acquisitions and the further exploitation and development of our properties. At December 31, 2003, our part of the estimated *proved reserves* these properties contain was approximately 5.0 million barrels (*MBbl*) of oil and 32.7 billion cubic feet (*Bcf*) of natural gas with a *Present Value discounted 10% (PV-10)* of $114.4 million. At present, all of our properties are located on land in Texas, Colorado, Louisiana and Oklahoma, except for the property on Grand Lake, Louisiana. In the future, we plan to expand by acquiring additional properties in those areas, and in similar properties located in other areas of the United States.

Our gross revenues are derived from the following sources:

1. **Oil and gas sales** that are proceeds from the sale of crude oil and natural gas production to midstream purchasers;

2. **Operating overhead and other income** that consists of earnings from operating crude oil and natural gas properties for other *working interest* owners, and marketing and transporting natural gas. This also includes earnings from other miscellaneous activities.

3. **Well servicing revenues** that are earnings from the operation of well servicing equipment under contract to other operators. During 2003, we worked only for our own account.

Our operations are considered to fall within a single industry segment, which is the acquisition, development, production and servicing of crude oil and natural gas properties. See Item 7. " Management's Discussion and Analysis of Financial Condition and Results of Operations." Certain industry terms are *italicized* and defined in the Glossary beginning on page 28.

Our common stock is traded over-the-counter (OTC) under the symbol "GULF".

Our Company.

We were formed as a corporation under the laws of the State of Utah in 1987 as Gallup Acquisitions, Inc., and subsequently changed our name to First Preference Fund, Inc. and then to GulfWest Energy, Inc. We became a Texas corporation by a merger effected in July 1992, in which our name became GulfWest Oil Company. On May 21, 2001, we changed our name to GulfWest Energy Inc.

Our principal office is located at 480 North Sam Houston Parkway East, Suite 300, Houston, Texas 77060 and our telephone number is (281) 820-1919.

GulfWest Energy Inc. has nine wholly owned subsidiaries:

1. **GulfWest Oil and Gas Company**, a Texas corporation, was organized February 18, 1999 and is the owner of record of interests in certain crude oil and natural gas properties located in Colorado and Texas.

2. **SETEX Oil and Gas Company**, a Texas corporation, was organized August 11, 1998 and is the operator of crude oil and natural gas properties in which we own the majority *working interest.*

3. **LTW Pipeline Co.**, a Texas corporation, was organized April 19, 1999, is the owner and operator of certain natural gas gathering systems and pipelines that we own, and markets the natural gas produced from our properties.

4. **RigWest Well Service, Inc.**, a Texas corporation, was organized September 5, 1996 and operates well servicing equipment for our own account.

5. **Southeast Texas Oil and Gas Company, L.L.C.**, a Texas company, was acquired by us on September 1, 1998 and is the owner of record of interests in certain crude oil and natural gas properties located in three Texas counties.

6. **DutchWest Oil Company**, a Texas corporation, was organized July 28, 1997 and is the owner of record of interests in certain crude oil and natural gas properties located along the Gulf Coast of Texas.

7. **GulfWest Development Company**, a Texas corporation, was organized November 9, 2000 and is the owner of record of interests in certain crude oil and natural gas properties located in Texas, Oklahoma and Mississippi.

8. **GulfWest Texas Company**, a Texas corporation, was organized September 23, 1996 and was the owner of interests in certain crude oil and natural gas properties located in the Vaughn Field, Crockett County, Texas. Effective April 1, 2000, these properties were assigned to GulfWest Oil and Gas Company to facilitate financing.

9. **GulfWest Oil and Gas Company (Louisiana) LLC**, a Louisiana company, was formed July 31, 2001 and is the owner of record of interests in certain crude oil and natural gas properties in Louisiana.

Our Business Strategy.

We have pursued a business strategy of acquiring interests in crude oil and natural gas *producing properties* where production and reserves can be increased through engineering and development activities. Such activities include *workovers*, development drilling, *recompletions*, replacement or addition of equipment and *waterflood* or other secondary recovery techniques. We have expanded our business plan to include an increased but controlled emphasis on development drilling for additional crude oil and natural gas reserves. Key elements of our business strategy include:

<u>*Continued Acquisition Program.*</u> We acquired properties in four crude oil and natural gas fields in Texas and Louisiana in the year 2001. We intend to continue to pursue interests in crude oil and natural gas properties (i) held by small, under-capitalized operators and (ii) being divested by larger independent and major oil and gas companies.

Development and Exploitation of Existing Properties. We intend to increase the development of properties in which we currently own interest by expanding our engineering and geological field studies. Our intent is to increase crude oil and natural gas production and reserves of our existing assets through relatively low-risk development activities, such as *workovers*, *recompletions*, *horizontal drilling* from existing wellbores and infield drilling, as well as the more efficient use of production facilities and the expansion of existing *waterflood* operations.

Significant Operating Control. Currently, we are the operator of all the wells, except two, in which we own *working interests*. This operating control enables us to better manage the nature, timing and costs of development of such wells, and marketing of the resulting production.

Ownership of Workover Rigs. We currently own three workover service rigs and one swabbing unit that we operate for our own account. By owning and operating this equipment, we are better able to control costs, quality of operations and availability of equipment and services.

Greater Natural Gas Ownership. At December 31, 2003, our reserves were comprised of 48% crude oil and 52% natural gas. We will continue to expand our role in the domestic natural gas industry by (i) acquiring additional interests in natural gas properties, (ii) increasing the production and reserve base of our existing natural gas properties, and (iii) acquiring ownership of more natural gas gathering systems and pipelines. We are presently focusing our *workover* and development efforts on both crude oil and natural gas reserves to take advantage of the higher prices of both commodities. We are also seeking to expand our ownership of gas gathering systems and pipelines located in our main field areas. Our goal is to have greater control of our natural gas transportation and marketing, and an expanded role in the transportation of natural gas produced by other parties in our area of operations.

Expanded Exploration and Exploitation Role. Historically, we have not drilled exploratory wells due to the cost and risk associated with drilling prospective locations. However, since the end of 1998, we have acquired *producing properties* that have included significant acreage for prospective oil and gas exploration. These include producing wells and acreage in Crockett, Grimes, Hardin, Jim Wells, Kimble, Madison, Palo Pinto, Refugio, Sutton, Wharton and Zavala, Counties, Texas; Adams, Arapaho, Elbert and Weld Counties, Colorado; Creek County, Oklahoma; and, Cameron Parish, Louisiana. These acquisitions have added existing natural gas and crude oil production to our asset base and, as importantly, have provided us with immediate geological databases for drilling opportunities. We have expanded our evaluation efforts in these fields and intend to increase our development of reserves, not only through workovers of existing wells, but by drilling additional wells.

Our Employees.

At December 31, 2003, we had 34 full time employees, of whom 22 were field personnel.

Our Executive Officers.

See Item 10 of this report, which information is incorporated herein by reference.

ITEM 2. Our Properties.

At December 31, 2003, we owned a total of 684 *gross wells*, of which 266 were *producing*, 351 were shut-in or temporarily abandoned and 67 were injection or saltwater wells. We owned an average 94% *working interest* in the 266 *gross (249.90 net) producing wells*. *Gross wells* are the total wells in which we own a *working interest*. *Net wells* are the sum of the fractional *working interests* we own in *gross wells*. Our part of the estimated *proved reserves* these properties contain was approximately 5.0 million barrels (*MBbl)* of oil and 32.7 billion cubic feet (B*cf)* of natural gas. Substantially all of our properties are located in Texas, Colorado, Louisiana and Oklahoma.

Proved Reserves.

The following table reflects our estimated *proved reserves* at December 31 for each of the preceding three years.

	2003	2002	2001
Crude Oil (*MBbl*)			
Developed	3,773	4,026	3,940
Undeveloped	1,265	1,496	1,932
Total	5,038	5,522	5,872
Natural Gas (*MMcf*)			
Developed	24,642	25,374	21,204
Undeveloped	8,018	8,785	18,054
Total	32,660	34,159	39,258
Total (*MBOE*)	10,481	11,215	12,415

(a) Approximately 75% of our total *proved reserves* were classified as *proved developed* at December 31, 2003.

(b) *Barrel of Oil Equivalent (BOE)* is based on a ratio of 6,000 cubic feet of natural gas for each barrel of oil.

Standardized Measure of Discounted Future Net Cash Flows.

The following table sets forth as of December 31 for each of the preceding three years, the estimated future net cash flow from and *standardized measure* of discounted future net cash flows of our *proved reserves*, which were prepared in accordance with the rules and regulations of the SEC. Future net cash flow represents future gross cash flow from the production and sale of *proved reserves*, net of crude oil and natural gas production costs (including production taxes, ad valorem taxes and operating expenses) and future development costs. The calculations used to produce the figures in this table are based on current cost and price factors at December 31 for each year. We cannot assure you that the *proved reserves* will all be developed within the periods used in the calculations or that prices and costs will remain constant.

	2003	2002	2001
Future cash inflows	$ 336,795,385	$ 308,381,837	$ 199,162,921
Future production and development costs-			
Production	109,468,727	105,629,872	77,526,278
Development	21,460,459	23,350,811	23,610,596
Future net cash flows before income taxes	205,866,199	179,401,154	98,026,047
Future income taxes	(46,885,360)	(38,611,577)	(13,281,358)
Future net cash flows after income taxes	158,980,839	140,789,577	84,744,689
10% annual discount for estimated timing of cash flows	(70,653,419)	(63,165,742)	(35,895,306)
Standardized measure of discounted Future net cash flows(1)	$ 88,327,420	$ 77,623,835	$ 48,849,383

(1) The average prices of our proved reserves were $29.51 per Bbl and $5.82 per *Mcf*, $28.72 per Bbl and $4.43 per *Mcf*, and $17.67 and $2.43 per *Mcf* at December 31, 2003, 2002 and 2001 respectively.

Significant Properties.

Summary information on our properties with *proved reserves* is set forth below as of December 31, 2003.

	Productive Wells		Proved Reserves			Present Value (1)
	Gross Productive Wells	Net Productive Wells	Crude Oil	Natural Gas	Total	Amount
			(MBbl)	*(MMcf)*	*(MBOE)*	($M)
Texas	185	181.03	2,969	18,717	6,088	$ 67,235
Colorado	35	23.62	355	6,090	1,370	11,303
Oklahoma	28	28.00	150	-	150	1,301
Louisiana	17	16.88	1,558	7,853	2,867	34,484
Mississippi	1	.37	6	-	6	73
Total	266	249.90	5,038	32,660	10,481	$ 114,396

(1) The average prices of our proved reserves were $29.51 per Bbl and $5.82 per *Mcf* at December 31, 2003.

All information set forth herein relating to our *proved reserves*, estimated future net cash flows and *present values* is taken from reports prepared by Pressler Petroleum Consultants, independent petroleum engineers. The estimates of these engineers were based upon their review of production histories and other geological, economic, ownership and engineering data provided by and relating to us. No reports on our reserves have been filed with any federal agency. In accordance with the SEC's guidelines, our estimates of *proved reserves* and the future net revenues from which *present values* are derived are made using year end crude oil and natural gas sales prices held constant throughout the life of the properties (except to the extent a contract specifically provides otherwise). Operating costs, development costs and certain production-related taxes were deducted in arriving at estimated future net revenues, but such costs do not include debt service, general and administrative expenses and income taxes.

There are numerous uncertainties inherent in estimating crude oil and natural gas reserves and their values, including many factors beyond our control. The reserve data set forth in this report are based upon estimates. *Reservoir* engineering is a subjective process, which involves estimating the sizes of underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation of that data, and judgment. As a result, estimates of different engineers, including those used by us, may vary. In addition, estimates of reserves are subject to revision based upon actual production, results of future development, exploitation and exploration activities, prevailing crude oil and natural gas prices, operating costs and other factors. Such revisions may be material. Accordingly, reserve estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered and are highly dependent upon the accuracy of the assumptions upon which they are based. We cannot assure you that the estimates contained in this report are accurate predictions of our crude oil and natural gas reserves or their values. Estimates with respect to *proved reserves* that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than upon actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in potentially substantial variations in the estimated reserves.

Production, Revenue and Price History.

The following table sets forth information (associated with our *proved reserves)* regarding production volumes of crude oil and natural gas, revenues and expenses attributable to such production (all net to our interests) and certain price and cost information for the years ended December 31, 2003, 2002 and 2001.

	2003	2002	2001
Production			
Oil (*Bbl*)	221,433	278,374	294,276
Natural gas (*Mcf*)	1,191,350	1,487,048	1,594,899
Total (*BOE*)	419,991	526,215	560,092
Revenue			
Oil production	$ 5,362,657	$ 5,859,568	$ 6,690,338
Natural gas production	5,481,803	4,587,601	5,735,765
Total	$10,844,460	$10,447,169	$12,426,103
Operating Expenses	$ 5,527,841	$ 5,430,205	$ 5,155,500
Production Data			
Average sales price			
Per barrel of oil	$ 24.22	$ 21.05	$ 22.73
Per *Mcf* of natural gas	4.60	3.09	3.60
Per *BOE*	25.82	19.85	22.19
Average expenses per *BOE*			
Lease operating	13.16	10.32	9.20
Depreciation, depletion and amortization	5.30	5.13	4.45
General and administrative	$ 5.39	$ 3.28	$ 3.05

Productive Wells at December 31, 2003:

The following table shows the number of productive wells we own by location:

	Gross Oil Wells	Net Oil Wells	Gross Gas Wells	Net Gas Wells
Texas	109	108.81	76	72.22
Colorado	22	14.37	13	9.25
Oklahoma	28	28.00	-	-
Louisiana	13	12.88	4	4.00
Mississippi	1	.37	-	-
Total	173	164.43	93	85.47

Developed Acreage at December 31, 2003.

The following table shows the developed acreage that we own, by location, which is acreage spaced or assigned to productive wells. *Gross acres* are the total acres in which we own a *working interest. Net acres* are the sum of the fractional *working interests* we own in *gross acres.*

	Gross Acres	Net Acres
Texas	18,380	14,255
Colorado	5,000	2,700
Louisiana	1,695	1,256
Oklahoma	900	684
Total	25,975	18,895

Undeveloped Acreage at December 31, 2003.

The following table shows the undeveloped acreage that we own, by location. Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas.

	Gross Acres	Net Acres
Texas	18,070	14,749
Colorado	10,000	6,000
Louisiana	80	55
Oklahoma	900	684
Total	29,050	21,488

Drilling Results.

We did not drill any wells in 2003. In 2002, we drilled one exploratory well, in which we own 18% *working interest,* that resulted in a dry hole and one development well, in which we own 100% *working interest,* that is productive. We drilled three wells in 2001, all of which were development wells and are currently productive. These development wells included two horizontal wells, in which we own 96% and 89% *working interest,* drilled by sidetracking from existing wellbores in the Madisonville Field, Texas, and one well, in which we own 100% *working interest,* that was deepened in our Leona River Field, Texas.

Risk Factors.

Our success depends heavily upon our ability to market our crude oil and natural gas production at favorable prices.

In recent decades, there have been both periods of worldwide overproduction and underproduction of crude oil and natural gas, and periods of increased and relaxed energy conservation efforts. Such conditions have resulted in excess supply of, and reduced demand for, crude oil on a worldwide basis and for natural gas on a domestic basis. At other times, there has been short supply of, and increased demand for, crude oil and, to a lesser extent, natural gas. These changes have resulted in dramatic price fluctuations.

The degree to which we are leveraged could possibly have important consequences to our shareholders, including the following:

(i) Our indebtedness, acquisitions, working capital, capital expenditures or other purposes may be impaired;

(ii) Funds available for our operations and general corporate purposes or for capital expenditures will be reduced as a result of the dedication of a substantial portion of our consolidated cash flow from operations to the payment of the principal and interest on our indebtedness;

(iii) We may be more highly leveraged than certain of our competitors, which may place us at a competitive disadvantage;

(iv) The agreements governing our long-term indebtedness and bank loans may contain restrictive financial and operating covenants;

(v) An event of default (not cured or waived) under financial and operating covenants contained in our debt instruments could occur and have a material adverse effect;

(vi) Certain of the borrowings under our debt agreements have floating rates of interest, which causes us to be vulnerable to increases in interest rates; and,

(vii) Our substantial degree of leverage could make us more vulnerable to a downturn in general economic conditions.

Our ability to make principal and interest payments under long-term indebtedness and bank loans will be dependent upon our future performance, which is subject to financial, economic and other factors, some of which are beyond our control.

We cannot assure you that our current level of operating results will continue or improve. We believe that we will need to access capital markets in the future in order to provide the funds necessary to repay a significant portion of our indebtedness. We cannot assure you that any such refinancing will be possible or that we can obtain any additional financing, particularly in view of our anticipated high levels of debt. If no such refinancing or additional financing were available, we could default on our debt obligations.

We have incurred net losses in the past and there can be no assurance that we will be profitable in the future.

Our future operating results may fluctuate significantly depending upon a number of factors, including industry conditions, prices of crude oil and natural gas, rates of production, timing of capital expenditures and drilling success. These variables could have a material adverse effect on our business, financial condition, results of operations and the market price of our common stock.

Estimates of crude oil and natural gas reserves depend on many assumptions that may turn our to be inaccurate.

Estimates of our *proved reserves* for crude oil and natural gas and the estimated future net revenues from the production of such reserves rely upon various assumptions, including assumptions as to crude oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating crude oil and natural gas reserves is complex and imprecise.

Actual future production, crude oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable crude oil and natural gas reserves may vary substantially from the estimates we obtain from reserve engineers. Any significant variance in these assumptions could materially affect the estimated quantities and *present value* of reserves we have set forth. In addition, our *proved reserves* may be subject to downward or upward revision due to factors that are beyond our control, such as production history, results of future exploration and development, prevailing crude oil and natural gas prices and other factors.

Approximately 25% of our total estimated *proved reserves* at December 31, 2003 were *proved undeveloped reserves*, which are by their nature less certain.

Recovery of such reserves requires significant capital expenditures and successful drilling operations. The reserve data set forth in the reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves. Although cost and reserve estimates attributable to our crude oil and natural gas reserves have been prepared in accordance with industry standards, we cannot be sure that the estimated costs are accurate, that development will occur as scheduled or that the results of such development will be as estimated.

You should not interpret the *present value* referred to in this report or documents incorporated herein by reference as the current market value of our estimated crude oil and natural gas reserves.

In accordance with SEC requirements, the estimated discounted future net cash flows from *proved reserves* are generally based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower.

The estimates of our *proved reserves* and the future net revenues from which the *present value* of our properties is derived were calculated based on the actual prices of our various properties on a property-by-property basis at December 31, 2003. The average prices of all properties were $29.51 per barrel of oil and $5.82 per thousand cubic feet (*Mcf*) of natural gas at that date.

Actual future net cash flows will also be affected by increases or decreases in consumption by crude oil and natural gas purchasers and changes in governmental regulations or taxation. The timing of both the production and the incurring of expenses in connection with the development and production of crude oil and natural gas properties affect the timing of actual future net cash flows from *proved reserves*. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and gas industry in general will affect the accuracy of the 10% discount factor.

Except to the extent that we acquire properties containing *proved reserves* or conduct successful development or exploitation activities, our *proved reserves* will decline as they are produced.

In general, the volume of production from crude oil and natural gas properties declines as reserves are depleted. Our future crude oil and natural gas production is highly dependent upon our success in finding or acquiring additional reserves.

The business of acquiring, enhancing or developing reserves requires considerable capital.

Our ability to make the necessary capital investment to maintain or expand our asset base of crude oil and natural gas reserves could be impaired to the extent that cash flow from operations is reduced and external sources of capital become limited or unavailable. In addition, we cannot be sure that our future acquisition and development activities will result in additional *proved reserves* or that we will be able to drill productive wells at acceptable costs.

Crude oil and natural gas drilling and production activities are subject to numerous risks, many of which are beyond our control.

These risks include (i) the possibility that no commercially productive oil or gas reservoirs will be encountered; and, (ii) that operations may be curtailed, delayed or canceled due to title problems, weather conditions, governmental requirements, mechanical difficulties, or delays in the delivery of drilling rigs and other equipment that may limit our ability to develop, produce and market our reserves. We cannot assure you that new wells we drill will be productive or that we will recover all or any portion of our investment in such new wells.

Drilling for crude oil and natural gas may not be profitable.

Any wells that we drill may be dry wells or wells that are not sufficiently productive to be profitable after drilling. Such wells will have a negative impact on our profitability. In addition, our properties may be susceptible to drainage from production by other operators on adjacent properties.

Our industry experiences numerous operating risks that could cause us to suffer substantial losses.

Such risks include fire, explosions, blowouts, pipe failure and environmental hazards, such as oil spills, natural gas leaks, ruptures or discharges of toxic gases. We could also suffer losses due to personnel injury or loss of life; severe damage to or destruction of property; or environmental damage that could result in clean-up responsibilities, regulatory investigation, penalties or suspension of our operations. In accordance with customary industry practice, we maintain insurance policies against some, but not all, of the risks described above. Our insurance policies may not adequately protect us against loss or liability. There is no guarantee that insurance policies that protect us against the many risks we face will continue to be available at justifiable premium levels.

As owners and operators of crude oil and natural gas properties, we may be liable under federal, state and local environmental regulations for activities involving water pollution, hazardous waste transport, storage, disposal or other activities.

Our past growth has been attributable to acquisitions of producing crude oil and natural gas properties with *proved reserves*. There are risks involved with such acquisitions.

The successful acquisition of properties requires an assessment of recoverable reserves, future crude oil and natural gas prices, operating costs, potential environmental and other liabilities, and other factors beyond our control. Such assessments are necessarily inexact and their accuracy uncertain. In connection with such an assessment, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Such a review, however, will not reveal all existing or potential problems, nor will it permit us, as the buyer, to become sufficiently familiar with the properties to fully assess their capabilities or deficiencies. We may not inspect every well and, even when an inspection is undertaken, structural and environmental problems may not necessarily be observable.

When we acquire properties, in most cases, we are not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities.

We generally acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. In those circumstances in which we have contractual indemnification rights for pre-closing liabilities, we cannot assure you that the seller will be able to fulfill its contractual obligations. In addition, the competition to acquire producing crude oil and natural gas properties is intense and many of our larger competitors have financial and other resources substantially greater than ours. We cannot assure you that we will be able to acquire producing crude oil and natural gas properties that have economically recoverable reserves for acceptable prices.

We may acquire *royalty, overriding royalty* or *working interests* in properties that are less than the controlling interest.

In such cases, it is likely that we will not operate, nor control the decisions affecting the operations, of such properties. We intend to limit such acquisitions to properties operated by competent parties with whom we have discussed their plans for operation of the properties.

We will need additional financing in the future to continue to fund our developmental and exploitation activities.

We have made and will continue to make substantial capital expenditures in our exploitation and development projects. We intend to finance these capital expenditures with cash flow from operations, existing financing arrangements or new financing. We cannot assure you that such additional financing will be available. If it is not available, our development and exploitation activities may have to be curtailed, which could adversely affect our business, financial condition and results of operations, as was the case in 2003.

The marketing of our natural gas production depends, in part, upon the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities.

We could be adversely affected by changes in existing arrangements with transporters of our natural gas since we do not own most of the gathering systems and pipelines through which our natural gas is delivered to purchasers. Our ability to produce and market our natural gas could also be adversely affected by federal, state and local regulation of production and transportation.

The crude oil and natural gas industry is highly competitive in all of its phases.

Competition is particularly intense with respect to the acquisition of desirable *producing properties*, the acquisition of crude oil and natural gas *prospects* suitable for enhanced production efforts, and the hiring of experienced personnel. Our competitors in crude oil and natural gas acquisition, development, and production include the major oil companies, in addition to numerous independent crude oil and natural gas companies, individual proprietors and drilling programs.

Many of these competitors possess and employ financial and personnel resources substantially in excess of those which are available to us and may, therefore, be able to pay more for desirable *producing properties* and *prospects* and to define, evaluate, bid for, and purchase a greater number of *producing properties* and *prospects* than our financial or personnel resources will permit. Our ability to generate reserves in the future will be dependent on our ability to select and acquire suitable *producing properties* and *prospects* while competing with these companies.

The domestic oil industry is extensively regulated at both the federal and state levels. Although we believe we are presently in compliance with all laws, rules and regulations, we cannot assure you that changes in such laws, rules or regulations, or the interpretation thereof, will not have a material adverse effect on our financial condition or the results of our operations.

Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden on the industry. There are numerous federal and state agencies authorized to issue rules and regulations affecting the oil and gas industry. These rules and regulations are often difficult and costly to comply with and carry substantial penalties for noncompliance.

State statutes and regulations require permits for drilling operations, drilling bonds, and reports concerning operations. Most states also have statutes and regulations governing conservation matters, including the unitization or pooling of properties, and the establishment of maximum rates of production from wells. Some states have also enacted statutes prescribing price ceilings for natural gas sold within their states.

Our industry is also subject to numerous laws and regulations governing plugging and abandonment of wells, discharge of materials into the environment and other matters relating to environmental protection. The heavy regulatory burden on the oil and gas industry increases the costs of our doing business as an oil and gas company, consequently affecting our profitability.

Our board of directors is authorized, without further shareholder action, to issue preferred stock in one or more series and to designate the dividend rate, voting rights and other rights, preferences and restrictions of each such series.

As of March 29, 2004, there was a total of 19,000 shares of preferred stock issued and outstanding in three series, including 8,000 shares of Series D, 9,000 shares of Series E and 2,000 shares of Series F. The 8,000 shares of Series D Preferred Stock are held by a former director, the 9,000 shares of Series E Preferred Stock are held by a current director and the 2,000 shares of Series F are held by our largest lender. Our preferred stock is senior to our common stock regarding liquidation. The holders of the preferred stock do not have voting rights or preemptive rights nor are they subject to the benefits of any retirement or sinking fund.

The Series D preferred stock is not entitled to dividends, nor is it redeemable, however it is convertible to common stock at anytime. None of the 8,000 outstanding shares of Series D preferred stock has been converted. On a fully converted basis, the 8,000 shares of Series D preferred stock would convert to 500,000 shares of common stock.

The Series E preferred stock is entitled to receive dividends at the rate of $12.50 per share per annum, payable quarterly, as declared by the board of directors, until June 30, 2004 when the dividend rate shall be increased to $30.00 per share per annum. The board of directors did not declare payment of dividends during 2003. The Series E preferred stock is redeemable in whole or in part at any time, at the option of the issuer, at a price of $500 per share, plus all accrued and undeclared or unpaid dividends; except that, prior to our redemption of the remaining, the holders of record shall be given a 60-day written notice of the issuer's intent to redeem and the opportunity to convert the Series E preferred stock to common stock. The conversion price for the Series E preferred stock is based on $2.00 per share of common stock. None of the 9,000 outstanding shares of Series E preferred stock has been redeemed or converted. On a fully converted basis, the 9,000 shares of Series E preferred stock would convert to 2,250,000 shares of common stock.

The Series F preferred stock is entitled to receive dividends at the rate of $12.50 per share per annum, payable quarterly, as declared by the board of directors, until May 30, 2006 when the dividend rate shall be increased to $30.00 per share per annum. The Series F preferred stock is redeemable in whole or in part at any time, at the option of the issuer, at a price of $500 per share, plus all accrued and undeclared or unpaid dividends; except that, after two years from the date of the original issuance, June 1, 2003, and prior to our redemption of the remaining shares, the holders of record shall be given a 60-day written notice of the issuer's intent to redeem and the opportunity to convert the Series F preferred stock to common stock. The conversion price for the Series F preferred stock is based on $1.00 per share of common stock. None of the 2,000 outstanding shares of Series F preferred stock has been redeemed or converted. On a fully converted basis, the 2,000 shares of Series F preferred stock would convert to 1,000,000 shares of common stock.

We do not pay dividends on our common stock.

Our board of directors presently intends to retain all of our earnings for the expansion of our business, therefore we do not anticipate distributing cash dividends on our common stock in the foreseeable future. Any decision of our board of directors to pay cash dividends will depend upon our earnings, financial position, cash requirements and other factors.

The holders of our common stock do not have cumulative voting rights, preemptive rights or rights to convert their common stock to other securities.

We are authorized to issue 40,000,000 shares of common stock, $.001 par value per share. As of March 29, 2004, there were 18,492,541 shares of common stock issued and outstanding. Since the holders of our common stock do not have cumulative voting rights, the holder(s) of a majority of the shares of common stock present, in person or by proxy, will be able to elect all of the members of our board of directors. The holders of shares of our common stock do not have preemptive rights or rights to convert their common stock into other securities. At December 31, 2003, we had outstanding warrants and options for the purchase of 3,067,000 shares of common stock at prices ranging from $.75 to $1.81 per share, including employee stock options to purchase 1,102,000 shares at prices ranging from $.75 to $1.81 per share. If we issue additional shares, the existing shareholders' percentage ownership of our company may be further diluted.

Actual results may differ from forward-looking statements.

We make forward-looking statements throughout this report. Whenever you read a statement that is not simply a statement of historical fact, such as when we describe what we "believe," "expect" or "anticipate" will occur, and other similar statements, you must remember that our expectations may not be correct, even though we believe they are reasonable. These forward-looking statements generally relate to our plans and objectives for future operations and are based upon our management's reasonable estimates of future results and trends. We do not guarantee that the transactions and events described will happen as described (or that they will happen at all). In connection with forward-looking statements, you should carefully review the factors set forth in this report under "Risk Factors."

ITEM 3. Legal Proceedings.

From time to time, we are involved in litigation relating to claims arising out of our operations or from disputes with vendors in the normal course of business. As of March 29, 2004, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on us.

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

We did not submit any matters to a vote of our security holders during the fourth quarter of the fiscal year ended December 31, 2003.

PART II

ITEM 5. Market for Our Common Stock and Related Stockholder Matters.

Our common stock is traded over-the-counter under the symbol "GULF". The high and low trading prices for the common stock for each quarter in 2003, 2002 and 2001 are set forth below. The trading prices represent prices between dealers, without retail mark-ups, mark-downs, or commissions, and may not necessarily represent actual transactions.

	High	Low
2003		
First Quarter	$.45	$.42
Second Quarter	.47	.35
Third Quarter	.47	.43
Fourth Quarter	.47	.32
2002		
First Quarter	$.66	$.55
Second Quarter	.60	.46
Third Quarter	.51	.20
Fourth Quarter	.44	.32
2001		
First Quarter	$1.46	$.39
Second Quarter	1.01	.53
Third Quarter	.96	.48
Fourth Quarter	.72	.58

We are authorized to issue 40,000,000 shares of Class A common stock, par value $.001 per share (the "common stock"). As of March 29, 2004, there were 18,492,541 shares of common stock issued and outstanding and held by approximately 580 beneficial owners. Our common stock is traded over-the-counter (OTC) under the symbol "GULF". Fidelity Transfer Company, 1800 South West Temple, Suite 301, Box 53, Salt Lake City, Utah 84115, (801) 484-7222 is the transfer agent for the common stock.

Holders of common stock are entitled, among other things, to one vote per share on each matter submitted to a vote of shareholders and, in the event of liquidation, to share ratably in the distribution of assets remaining after payment of liabilities (including preferential distribution and dividend rights of holders of preferred stock). Holders of common stock have no cumulative rights, and, accordingly, the holders of a majority of the outstanding shares of the common stock have the ability to elect all of the directors.

Holders of common stock have no preemptive or other rights to subscribe for shares. Holders of common stock are entitled to such dividends as may be declared by the Board out of funds legally available therefore. We have never paid cash dividends on the common stock and do not anticipate paying any cash dividends in the foreseeable future.

Preferred Stock.

Our board of directors is authorized, without further shareholder action, to issue preferred stock in one or more series and to designate the dividend rate, voting rights and other rights, preferences and restrictions of each such series.

As of March 29, 2004, there was a total of 19,000 shares of preferred stock issued and outstanding in three series, including 8,000 shares of Series D, 9,000 shares of Series E and 2,000 shares of Series F. The 8,000 shares of Series D Preferred Stock are held by a former director, the 9,000 shares of Series E Preferred Stock are held by a current director and the 2,000 shares of Series F are held by our largest lender. Our preferred stock is senior to our common stock regarding liquidation. The holders of the preferred stock do not have voting rights or preemptive rights nor are they subject to the benefits of any retirement or sinking fund.

The Series D preferred stock is not entitled to dividends, nor is it redeemable, however it is convertible to common stock at anytime. None of the 8,000 outstanding shares of Series D preferred stock has been converted. On a fully converted basis, the 8,000 shares of Series D preferred stock would convert to 500,000 shares of common stock.

The Series E preferred stock is entitled to receive dividends at the rate of $12.50 per share per annum, payable quarterly, as declared by the board of directors, until June 30, 2004 when the dividend rate shall be increased to $30.00 per share per annum. The board of directors did not declare payment of dividends during 2003. The Series E preferred stock is redeemable in whole or in part at any time, at the option of the issuer, at a price of $500 per share, plus all accrued and undeclared or unpaid dividends; except that, prior to our redemption of the remaining shares, the holders of record shall be given a 60-day written notice of the issuer's intent to redeem and the opportunity to convert the Series E preferred stock to common stock. The conversion price for the Series E preferred stock is based on $2.00 per share of common stock. None of the 9,000 outstanding shares of Series E preferred stock has been redeemed or converted. On a fully converted basis, the 9,000 shares of Series E preferred stock would convert to 2,250,000 shares of common stock.

The Series F preferred stock is entitled to receive dividends at the rate of $12.50 per share per annum, payable quarterly, as declared by the board of directors, until May 30, 2006 when the dividend rate shall be increased to $30.00 per share per annum. The Series F preferred stock is redeemable in whole or in part at any time, at the option of the issuer, at a price of $500 per share, plus all accrued and undeclared or unpaid dividends; except that, after two years from the date of the original issuance, June 1, 2003, and prior to our redemption of the remaining shares, the holders of record shall be given a 60-day written notice of the issuer's intent to redeem and the opportunity to convert the Series F preferred stock to common stock. The conversion price for the Series F preferred stock is based on $1.00 per share of common stock. None of the 2,000 outstanding shares of Series F preferred stock has been redeemed or converted. On a fully converted basis, the 2,000 shares of Series F preferred stock would convert to 1,000,000 shares of common stock.

Outstanding Options and Warrants.

At March 29, 2004, we had outstanding warrants and options for the purchase 3,067,000 shares of common stock at prices ranging from $.75 to $1.81 per share, including employee stock options to purchase 1,102,000 shares at prices ranging from $.75 to $1.81 per share.

Recent Sales of Unregistered Securities.

During 2002 and 2003, and to March 29, 2004, we granted warrants or options exercisable for shares of common stock not registered under the Securities Act of 1933, as amended, and exempt under Section 4(2) of the Act. All the grantees were current employees, consultants or accredited investors not affiliated with the company. No underwriters were used, and no underwriting discounts or commissions were paid in connection with the grants.

Date	Derivative	Grantee(s)	Exercisable Shares	Exercise Price	Consideration
02/25/02	Warrant	Director[1]	270,000	$ .75	Compensation
04/30/02	Warrant	Employee	100,000	$ .75	Compensation
07/15/02	Warrant	Accredited Investor	75,000	$ .75	Loan transaction
10/31/02	Option	Employee	35,000	$ .75	Compensation
11/06/02	Warrant	Director	625,000	$ .75	Loan transaction
12/02/02	Warrant	Accredited Investor	75,000	$ .75	Loan transaction
01/24/03	Warrant	Accredited Investor	100,000	$ .75	Loan transaction
02/12/03	Warrant	Accredited Investor	50,000	$ .75	Loan transaction
04/01/03	Option	Employee	35,000	$ .75	Compensation

[1] 200,000, 50,000 and 20,000 warrants originally issued to an officer/director (currently a director) in 1996 at exercise prices of $3.00, $5.00 and $5.75, respectively, were re-priced to $.75 per share.

ITEM 6. Selected Financial Data.

The following table sets forth selected historical financial data of our company as of December 31, 2003, 2002, 2001, 2000 and 1999, and for each of the periods then ended. See "Item 1. Business" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations." The income statement data for the years ended December 31, 2003, 2002 and 2001 and the balance sheet data at December 31, 2003 and 2002 are derived from our audited financial statements contained elsewhere herein. The income statement data for the years ended December 31, 2000 and 1999 and the balance sheet data at December 31, 2001, 2000 and 1999 are derived from our Annual Report on Form 10-K for those periods. You should read this data in conjunction with our consolidated financial statements and the notes thereto included elsewhere herein.

	Year Ended December 31,				
	2003	2002	2001	2000	1999
Income Statement Data					
Operating Revenues	$ 11,010,723	$ 10,839,797	$ 12,990,581	$ 8,984,175	$ 2,812,639
Net income (loss) from operations	917,571	927,655	3,451,875	2,464,017	(1,464,094)
Net income (loss)	(3,024,426)	(4,502,313)	1,044,291	352,774	(2,269,506)
Dividends on preferred stock	(127,083)	(112,500)	(56,250)	-	(450,684)
Net income (loss) available to common shareholders	(3,151,509)	(4,614,813)	988,401	352,774	(2,720,190)
Net income (loss), per share of common stock	$ (.17)	$ (.25)	$ .05	$ .02	$ (.34)
Weighted average number of shares of common stock outstanding	18,492,541	18,492,541	18,464,343	17,293,848	7,953,147
Balance Sheet Data					
Current assets	$ 1,742,689	$ 2,353,046	$ 2,205,862	$ 2,934,804	$ 1,357,465
Total assets	52,428,774	53,088,941	51,379,209	32,374,128	20,009,793
Current liabilities	44,619,652	43,998,566	12,492,365	7,594,986	4,650,691
Long-term obligations	1,393,607	137,808	26,541,957	18,077,371	11,304,318
Other liabilities	591,467	1,128,993	-	-	-
Stockholders' Equity	$ 5,824,648	$ 7,823,574	$ 12,344,887	$ 6,701,771	$ 4,054,784

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

Overview.

We are engaged primarily in the acquisition, development, exploitation, exploration and production of crude oil and natural gas. Our focus is on increasing production from our existing crude oil and natural gas properties through the further exploitation, development and exploration of those properties, and on acquiring additional interests in crude oil and natural gas properties. Our gross revenues are derived from the following sources:

1. **Oil and gas sales** that are proceeds from the sale of crude oil and natural gas production to midstream purchasers;

2. **Operating overhead and other income** that consists of earnings from operating crude oil and natural gas properties for other *working interest* owners, and marketing and transporting natural gas. This also includes earnings from other miscellaneous activities.

3. **Well servicing revenues** that are earnings from the operation of well servicing equipment under contract to other operators. During 2003, we worked only for our own account.

The following is a discussion of our consolidated financial condition, results of operations, financial condition and capital resources. You should read this discussion in conjunction with our Consolidated Financial Statements and the Notes thereto contained elsewhere herein. See "Financial Statements."

Results of Operations.

The factors which most significantly affect our results of operations are (1) the sales price of crude oil and natural gas, (2) the level of total sales volumes of crude oil and natural gas, (3) the cost and efficiency of operating our own properties, (4) depletion and depreciation of oil and gas property costs and related equipment (5) the level of and interest rates on borrowings, (6) the level and success of new acquisitions and development of existing properties, and (7) the adoption of changes in accounting rules.

We consider depletion and depreciation of oil and gas properties and related support equipment to be critical accounting estimates, based upon estimates of oil and gas reserves.

The estimates of oil and gas reserves utilized in the calculation of depletion and depreciation are estimated in accordance with guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations over prices and costs existing at year end, except by contractual arrangements.

We emphasize that reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. Our policy is to amortize capitalized oil and gas costs on the unit of production method, based upon these reserve estimates. It is reasonably possible the estimates of future cash inflows, future gross revenues, the amount of oil and gas reserves, the remaining estimated lives of the oil and gas properties, or any combination of the above may be increased or reduced in the near term. If reduced, the carrying amount of capitalized oil and gas properties may be reduced materially in the near term.

Comparative results of operations for the periods indicated are discussed below.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

Revenues

Oil and Gas Sales. Our operating revenues from the sale of crude oil and natural gas increased by 4% from $10,447,000 in 2002 to $10,844,000 in 2003. This increase was due to higher sales prices but offset by normal oil and gas production declines and lower production volumes. We were unable to offset those declines and maintain or increase production through development efforts because of limited development capital.

Well Servicing Revenues. There were no revenues from our well servicing operations in 2003 compared to $39,000 in 2002 since we ceased performing work for other operators and concentrated on our own properties.

Operating Overhead and Other Income. Revenues from these activities decreased 53% from $354,000 in 2002 to $166,000 in 2003, primarily due to (1) the loss of an oil and gas marketing contract and (2) lower pipeline volumes resulting in less transportation revenue.

Costs and Expenses

Lease Operating Expenses. Lease operating expenses increased 2% from $5,430,000 in 2002 to $5,528,000 in 2003 due to increased vendor prices.

Cost of Well Servicing Operations. There were no well servicing expenses in 2003 compared to $56,000 in 2002 since we did not work for other operators.

Depreciation, Depletion and Amortization (DD and A). DD and A decreased 17% from $2,698,000 in 2002 to $2,226,000 in 2003, due to lower production volumes. We also recorded income of $262,000 related to the cumulative effect of adopting SFAS 143.

Accretion Expense. We recorded accretion expense of $77,000 as a result of adopting SFAS 143 "Asset Retirement Obligation", effective January 1, 2003.

General and Administrative (G and A) Expenses. G and A expenses increased 31% from $1,728,000 in 2002 to $2,262,000 in 2003 due to expenses associated with financing efforts that were not culminated.

Interest Income and Expense. Interest expense increased 6% from $3,159,000 in 2002 to $3,363,000 in 2003 due to penalty interest paid to our largest lender under a provision in the loan agreement.

Other Financing Costs. In 2003, we recorded an expense of $1,000,000 to account for the issuance of 2,000 shares of our preferred stock to our largest lender under a financial agreement.

Unrealized Gain (Loss) on Derivative Instruments. The estimated future fair value of derivative instruments at December 31, 2003 resulted in an unrealized gain of $537,000 in 2003 compared to an unrealized loss of $1,597,000 in 2002.

Dry Holes, Abandoned Property and Impaired Assets. The cost of abandoned property in 2003 was $538,000 because the lack of capital to complete projects resulted in the loss of leases. This compared to combined costs of dry holes, abandoned property and impaired assets of $617,000 in 2002.

Dividends on Preferred Stock. In 2003, dividends on preferred stock due was $127,000, however the board of directors did not declare any dividends be paid. In 2002, dividends on preferred stock due was $112,000 and paid was $112,000.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Revenues

Oil and Gas Sales. Our operating revenues from the sale of crude oil and natural gas decreased by 16% from $12,426,000 in 2001 to $10,447,000 in 2002. This decrease resulted from normal oil and gas production declines and the inability to offset those declines through development efforts because of limited development capital.

Well Servicing Revenues. Revenues from our well servicing operations decreased by 77% from $169,000 in 2001 to $39,000 in 2002. This decrease was due to performing less work for third parties and the sale of one of our workover rigs.

Operating Overhead and Other Income. Revenues from these activities decreased 10% from $395,000 in 2001 to $354,000 in 2002, primarily as a result of the termination of a gas transportation sales contract with a local utility.

Costs and Expenses

Lease Operating Expenses. Lease operating expenses increased 5% from $5,155,000 in 2001 to $5,430,000 in 2002 due to increased vendor prices.

Cost of Well Servicing Operations. Well servicing expenses decreased 69% from $182,000 in 2001 to $56,000 in 2002 due to less work under contract to third parties and the sale of one workover rig.

Depreciation, Depletion and Amortization (DD and A). DD and A increased 8% from $2,491,000 in 2001 to $2,698,000 in 2002, due to our proved reserves being calculated slightly lower at the end of 2001.

General and Administrative (G and A) Expenses. G and A expenses increased only slightly from $1,710,000 in 2001 to $1,728,000 in 2002.

Interest Income and Expense. Interest expense increased 15% from $2,757,000 in 2001 to $3,159,000 in 2002 due to increased debt associated with the funding of acquisitions in August, 2001, capital used in our development program and issuance of warrants associated with working capital loans.

Unrealized Gain (Loss) on Derivative Instruments. The estimated future fair value of derivative instruments at December 31, 2002 resulted in an unrealized loss of $1,597,000 in 2002 compared to an unrealized gain of $4,215,000 in 2001. Also in 2001, an unrealized loss of $3,747,000, resulting from the cumulative effect of adopting SFAS No. 133 "Accounting for Derivative Instruments and Other Hedging Activities," was recorded.

Dry Holes, Abandoned Property, Impaired Assets. The costs of a dry hole in Louisiana of $339,000, abandoned property in Oklahoma of $222,000 and impaired assets in Mississippi of $55,000 totaled $617,000 in 2002 compared to none in 2001.

Dividends on preferred stock due was $112,000 and paid was $112,000 in 2002. Dividends on preferred stock due was $56,000 and paid was $28,000 in 2001.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Revenues

Oil and Gas Sales. Our operating revenues from the sale of crude oil and natural gas increased by 47% from $8,446,000 in 2000 to $12,426,000 in 2001, due to increased oil and gas production from development projects and acquisitions of additional properties.

Well Servicing Revenues. Revenues from our well servicing operations decreased by 10% from $188,000 in 2000 to $169,000 in 2001. This decrease was due to higher rig utilization on operated properties where we have *working interest* partners and less work for third parties.

Operating Overhead and Other Income. Revenues from these activities increased 13% from $350,000 in 2000 to $395,000 in 2001. Major components of the increase included operating overhead $82,000, gathering and marketing $211,000, sale of exploratory leases $96,000 and miscellaneous income $6,000.

Costs and Expenses

Lease Operating Expenses. Lease operating expenses increased 53% from $3,378,000 in 2000 to $5,155,000 in 2001. This increase in operating expenses was due to the acquisitions of additional properties, expanded oil and gas production, and increased vendor prices.

Cost of Well Servicing Operations. Well servicing expenses decreased 14% from $212,000 in 2000 to $182,000 in 2001. This decrease in expenses was due to less utilization of our equipment under contract to third parties.

Depreciation, Depletion and Amortization (DD and A). DD and A increased 86% from $1,342,000 in 2000 to $2,491,000 in 2001, due to significantly higher production resulting from successful field development activities and acquisitions.

General and Administrative (G and A) Expenses. G and A expenses increased 8% from $1,588,000 in 2000 to $1,710,000 in 2001 due to the increased number of properties being managed.

Interest Expense and Dividends on Preferred Stock. Interest expense increased 29% from $2,135,000 in 2000 to $2,757,000 in 2001 due to increased debt associated with the funding of our additional acquisitions and capital development program.

Unrealized Gain (Loss) on Derivative Instruments. The estimated future fair value of derivative instruments at December 31, 2001 resulted in an unrealized gain of $4,215,000 in 2001. Also in 2001, an unrealized loss of $3,747,000, resulting from the cumulative effect of adopting SFAS No. 133 "Accounting for Derivative Instruments and Other Hedging Activities," was recorded. There was no unrealized gain or loss in 2000.

Dividends on preferred stock due was $56,000 and paid was $28,000 in 2001. No dividends were due or paid in 2000.

Financial Condition and Capital Resources.

At December 31, 2003, our current liabilities exceeded our current assets by $42,876,963. We had a loss available to common shareholders of $3,151,509 compared to a loss available to common shareholders of $4,614,813 at December 31, 2002. This loss included non-cash items of $537,526 for unrealized gain on derivative instruments, a loss of $358,737 for abandonment of properties and a $262,452 gain from the recording of Asset Retirement Obligations ("ARO's"), as required by SFAS 143, at January 1, 2003.

In 2004, we will continue the recapitalization of debt and funding of our capital development program that we began in 2003. Following are the steps we are taking and plan to take to achieve that purpose:

(a) The first step is to close the refinancing of our largest debt of $27.8 million held by Concert Capital Resources LP ("CCR") and loaned to our wholly-owned subsidiary, GulfWest Oil & Gas Company. We have entered into an agreement with a new lending source that, subject to due diligence, will fund approximately $14 million to purchase the $27.8 million note. The new debt financing will also provide for the payment of closing costs. CCR has agreed to sell the note to our new financier for a $14 million cash payment and a $4 million subordinated note from us.

(b) Secondly, we are continuing to work with our financial advisor to raise an additional $4 to $5 million through the sale of our preferred stock. Proceeds from this equity sale will be used for working capital and fund our new development projects. The refinancing of the CCR debt and sale of new equity are both currently scheduled to close in April, 2004.

(c) Effective December 1, 2001 and amended August 16, 2002, we entered into an Oil and Gas Property Acquisition, Exploration and Development Agreement (the "Summit Agreement") with Summit Investment Group-Texas, L.L.C., an unrelated party, ("Summit"). Under the agreement, Summit provided payments in the aggregate of $1,200,000 in advanced funds for our use in the acquisition of oil and gas leases and other mineral and royalty interests, and production activities, and was to recoup and recover those advanced funds.

In a subsequent event on March 5, 2004, we entered into an Option Agreement for the Purchase of Oil and Gas Leases (the "Addison Agreement") with W. L. Addison Investments L.L.C., a private company owned by Mr. J. Virgil Waggoner and Mr. John E. Loehr, two of our directors, ('Addison"). Under the Addison Agreement, Addison agreed to pay Summit, on our behalf, the non-recouped and outstanding advanced funds amounting to $1,200,000, thereby retiring the Summit Agreement. For consideration of such payment, Addison acquired certain oil and gas leases and wellbores from Summit but agreed to grant us a 180-day redemption option (which may be extended by mutual consent) to purchase the same for $1,200,000, plus interest at the prime rate plus 2%. We tendered Addison a promissory note in the amount of $600,000, with interest at the prime rate plus 2%, to substitute for an account payable to Summit, pursuant to the Summit Agreement, in the same amount. The note will be considered paid in full if we exercise the redemption option and pay the $1,200,000, plus interest. Summit retained the right to participate up to a 25% *working interest* in the drilling of any wells on the leases acquired by Addison. In the event we exercise the redemption option, Addison may, at its sole option, retain up to a 25% *working interest* in the leases.

(d) Finally, after completing the above, we will pursue the consolidation of all of our debt, including other asset and bridge loans. Our goal is to simplify our financial structure and provide adequate capitalization for the development of our oil and gas assets.

Inflation and Changes in Prices.

While the general level of inflation affects certain costs associated with the petroleum industry, factors unique to the industry result in independent price fluctuations. Such price changes have had, and will continue to have a material effect on our operations; however, we cannot predict these fluctuations.

The following table indicates the average crude oil and natural gas prices received over the last three years by quarter. Average prices per barrel of oil equivalent, computed by converting natural gas production to crude oil equivalents at the rate of 6 *Mcf* per barrel, indicate the composite impact of changes in crude oil and natural gas prices.

	Average Prices		
	Crude Oil And Liquids (per Bbl)	Natural Gas (per Mcf)	Per Equivalent Barrel
2003			
First	$ 24.53	$ 5.36	$ 28.08
Second	23.53	4.47	25.04
Third	23.85	4.32	24.86
Fourth	24.99	4.56	25.02
2002			
First	$ 19.40	$ 2.81	$ 18.31
Second	20.75	3.16	19.83
Third	22.04	2.87	19.67
Fourth	22.38	3.56	22.11
2001			
First	$ 24.15	$ 5.27	$ 27.87
Second	24.14	3.88	23.71
Third	23.25	3.08	21.08
Fourth	19.94	2.62	17.96

ITEM 7a. Qualitative and Quantitative Disclosures About Market Risk.

Information with respect to qualitative disclosures about material risk is contained in Item 1 "Risk Factors".

Information with respect to quantitative disclosures about material risk follow:

All of our financial instruments are for purposes other than trading. We only enter derivative financial instruments in conjunction with our oil and gas hedging activities.

Hypothetical changes in interest rates and prices chosen for the following stimulated sensitivity effects are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. It is not possible to accurately predict future changes in interest rates and product prices. Accordingly, these hypothetical changes may not be an indicator of probable future fluctuations.

Interest Rate Risk

We are exposed to interest rate risk on debt with variable interest rates. At December 31, 2003, we carried variable rate debt of $37,955,334. Assuming a one percentage point change at December 31, 2003 on our variable rate debt, the annual pretax income (loss) would change by $379,553.

Commodity Price Risk

We hedge a portion of its price risks associated with its oil and natural gas sales which are classified as derivative instruments. As of December 31, 2003, these derivative instruments' liabilities had a fair value of $591,467. Fair value was estimated based upon the net present value of expected future cash flows, comparing prices for oil and gas in the hedge contract with quoted oil and gas futures prices. A hypothetical change in oil and gas prices could have an effect on oil and gas futures prices, which are used to estimate the fair value of our derivative instrument. However, it is not practicable to estimate the resultant change, in any, in the fair value of our derivative instrument.

ITEM 8. Financial Statements and Supplementary Data.

Information with respect to this Item 8 is contained in our financial statements beginning on Page F-1 of this Annual Report.

ITEM 9. Changes In and Disagreements With Accountants and Accounting and Financial Disclosure.

None

ITEM 9A. Controls and Procedures

Within ninety days of the date of this Report, we carried out an evaluation, under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, of our disclosure controls and procedures (as defined in Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective in timely alerting them to material information required to be included in periodic filings with the Securities and Exchange Commission. There were no significant changes in our internal controls or in other factors that could significantly affect these internal controls subsequent to the date of our most recent evaluation.

PART III

ITEM 10. Directors and Executive Officers of the Registrant.

The following table sets forth information on our directors and executive officers:

Name	Age	Position	Year First Elected Director or Officer
J. Virgil Waggoner(1)(2)	76	Chairman of the Board	1997
Thomas R. Kaetzer	45	Chief Executive Officer President and Director	1998
Jim C. Bigham	68	Executive Vice President and Secretary	1991
Richard L. Creel	55	Vice President of Finance and Controller	1998
Marshall A. Smith III	56	Director	1989
John E. Loehr(1)(2)	58	Director	1992
M. Scott Manolis(1)(2)	50	Director	2003

(1) Member of the Audit Committee.
(2) Member of the Compensation Committee.

J. Virgil Waggoner has served as a director of GulfWest since December 1, 1997 and was elected Chairman of the Board in May, 2002. Mr. Waggoner's career in the petrochemical industry began in 1950 and included senior management positions with Monsanto Company and El Paso Products Company, the petrochemical and plastics unit of El Paso Company. He served as president and chief executive officer of Sterling Chemicals, Inc. from the firm's inception in 1986 until its sale and his retirement in 1996. He is currently chief executive officer of JVW Investments, Ltd., a private company.

Thomas R. Kaetzer was appointed senior vice president and chief operating officer of GulfWest on September 15, 1998 and on December 21, 1998 became president and a director. On March 20, 2001, he was appointed chief executive officer. Mr. Kaetzer has 17 years experience in the oil and gas industry, including 14 years with Texaco Inc., which involved the evaluation, exploitation and management of oil and gas assets. He has both onshore and offshore experience in operations and production management, asset acquisition, development, drilling and *workovers* in the continental U.S., Gulf of Mexico, North Sea, Colombia, Saudi Arabia, China and West Africa. Mr. Kaetzer has a Masters Degree in Petroleum Engineering from Tulane University and a Bachelor of Science Degree in Civil Engineering from the University of Illinois.

Jim C. Bigham has served as secretary since 1991 and as executive vice president of GulfWest since 1996. Prior to joining GulfWest, he held management and sales positions in the real estate and printing industries. Mr. Bigham is also a retired United States Air Force Major. During his military career, he served in both command and staff officer positions in the operational, intelligence and planning areas.

Richard L. Creel has served as controller of GulfWest since May 1, 1997 and was elected vice president of finance on May 28, 1998. Prior to joining GulfWest, Mr. Creel served as Branch Manager of the Nashville, Tennessee office of Management Reports and Services, Inc. He has also served as controller of TLO Energy Corp. He has extensive experience in general accounting, petroleum accounting, and financial consulting and income tax preparation.

Marshall A. Smith III founded GulfWest and served as an officer in various capacities, including president, chief executive officer and chairman of the board, from July 1989 until his resignation in May 2002. He is currently a paid consultant and remains a director.

John E. Loehr has served as a director of GulfWest since 1992, was chairman of the board from September 1, 1993 to July 8, 1998 and was chief financial officer from November 22, 1996 to May 28, 1998. He is also currently president and sole shareholder of ST Advisory Corporation, an investment company, and vice-president of Star-Tex Trading Company, also an investment company. He was formerly president of Star-Tex Asset Management, a commodity-trading advisor, and a position he held from 1988 until 1992 when he sold his ownership interest. Mr. Loehr is a CPA and a member of the American Institute of Certified Public Accountants.

M. Scott Manolis is newly nominated to the board. He is the chairman and chief executive officer of Intermarket Management, LLC and Intermarket Brokerage, LLC. He has over twenty years experience in commodity risk management, commodity finance and commodity-based investments. Prior to founding Intermarket, Mr. Manolis concurrently served as managing director of Commodity Strategies for Refco Group, LTD. and Managing Director of Global Derivatives Strategies for Forstmann-Leff International (an asset management firm wholly owned by Refco Group, LTD), where he directed commodity-based investments. Prior to that, he served as a vice president and director of the Commodity Portfolio Management Group at Jefferies & Company. He received a B. S. in Economics from the University of South Dakota in 1979.

Our directors are elected annually and hold office until the next annual meeting of shareholders and until their successors are duly elected and qualified. The board of directors met 4 times during the calendar year ended December 31, 2003.

Committees of the Board of Directors.

Our board of directors has established an audit committee and a compensation committee. The functions of these committees, their current members, and the number of meetings held during 2003 are described below.

The audit committee was established to review and appraise the audit efforts of our independent auditors, and monitor our accounts, procedures and internal controls. The committee is comprised of Mr. John E. Loehr (Chairman), Mr. J. Virgil Waggoner and Mr. M. Scott Manolis. The committee met twice in 2003.

The function of the compensation committee is to fix the annual salaries and other compensation for our officers and key employees. The committee is comprised of Mr. J. Virgil Waggoner (Chairman), Mr. John E. Loehr and Mr. M. Scott Manolis. The committee met twice in 2003.

Compensation of Directors.

The shareholders approved an amended and restated Employee Stock Option Plan on May 28, 1998, which included a provision for the payment of reasonable fees in cash or stock to directors. No fees were paid to directors in 2003 or 2002.

ITEM 11. Executive Compensation.

Information regarding executive compensation is incorporated herein by reference to our Proxy Statement.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management.

Information regarding security ownership of certain beneficial owners and management is incorporated herein by reference to our Proxy Statement.

ITEM 13. Certain Relationships and Related Transactions.

Information regarding certain relationships and related transactions is incorporated herein by reference to our Proxy Statement.

ITEM 14. Principal Accounting Fees and Services.

Information regarding principal accounting fees and services is incorporated herein by reference to our Proxy Statement.

GLOSSARY OF INDUSTRY TERMS AND ABBREVIATIONS

The following are definitions of certain industry terms and abbreviations used in this report:

Bbl. Barrel.

BOE. Barrel of oil equivalent, based on a ratio of 6,000 cubic feet of natural gas for each barrel of oil.

Gross Acres or Gross Wells. The total acres or wells, as the case may be, in which a *working interest*s is owned.

Horizontal Drilling. High angle directional drilling with lateral penetration of one or more productive *reservoirs*.

Mcf. One thousand cubic feet.

Net Acres or Net Wells. The sum of the fractional *working interest*s owned in *gross acres* or *gross wells.*

Overriding Royalty Interest. The right to receive a share of the *proceeds of production* from a well, free of all costs and expenses, except transportation.

Present Value. The pre-tax present value, discounted at 10%, of future net cash flows from estimated proved reserves, calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the Commission's rules for inclusion of oil and gas reserve information in financial statements filed with the Commission.

Proceeds of Production. Money received (usually monthly) from the sale of oil and gas produced from *producing properties.*

Producing Properties. Properties that contain one or more wells that produce oil and/or gas in paying quantities (i.e., a well for which proceeds from production exceed operating expenses).

Productive Well. A well that is producing oil or gas or that is capable of production.

Prospect. A lease or group of leases containing possible reserves, capable of producing crude oil, natural gas, or natural gas liquids in commercial quantities, either at the time of acquisition, or after vertical or horizontal drilling, completion of *workovers*, *recompletion*s, or operational modifications.

Proved Reserves. Estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known *reservoirs* under existing economic conditions; i.e., prices and costs as of the date the estimate is made. *Reservoirs* are considered proved if either actual production or a conclusive formation test supports economic production.

The area of a *reservoir* considered proved includes:

a. That portion delineated by drilling and defining by gas-oil or oil-water contacts, if any; and

b. The immediately adjoining portions not yet drilled but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Proved Reserves do not include:

a. Oil that may become available from known *reservoirs* but is classified separately as "indicated additional reserves";

b. Crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, *reservoir* characteristics, or economic factors;

c. Crude oil, natural gas, and natural gas liquids that may occur in undrilled *prospects*; and

d. Crude oil, natural gas, and natural gas liquids that may be recovered from oil shales and other sources.

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

Proved Undeveloped Reserves. Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for *recompletion.* Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other units that have not been drilled can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for *proved undeveloped reserves* be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proven effective by actual tests in the area and in the same *reservoir.*

Recompletion. The completion for production of an existing wellbore in another formation from that in which the well has previously been completed.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Royalty. The right to a share of production from a well, free of all costs and expenses, except transportation.

Royalty Interest. An interest in an oil and gas property entitling the owner to a share of oil and natural gas production free of costs of production.

Standardized Measure. The present value, discounted at 10%, of future net cash flows from estimated proved reserves, after income taxes, calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the Commission's rules for inclusion of oil and gas reserve information in financial statements filed with the Commission.

Waterflood. An engineered, planned effort to inject water into an existing oil *reservoir* with the intent of increasing oil reserve recovery and production rates.

Working Interest. The operating interest under a lease, the owner of which has the right to explore for and produce oil and gas covered by such lease. The full working interest bears 100 percent of the costs of exploration, development, production, and operation, and is entitled to the portion of gross revenue from the *proceeds of production* which remains after proceeds allocable to *royalty* and *overriding royalty interest*s or other lease burdens have been deducted.

Workover. Rig work performed to restore an existing well to production or improve its production from the current existing *reservoir.*

PART III

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

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

(1) Financial Statements:
Consolidated Balance Sheets at December 31, 2003 and 2002.
Consolidated Statements of Operations for the years ended December 31, 2003, 2002 and 2001.
Consolidated Statements of Stockholders' Equity for the years ended December 31, 2003, 2002 and 2001.
Consolidated Statements of Cash Flows for the years ended December 31, 2003, 2002 and 2001.
Notes to Consolidated Financial Statements, December 31, 2003, 2002 and 2001.

(2) Financial Statement Schedule:
Schedule II - Valuation and Qualifying Accounts

(3) Exhibits:

Number	Description
*3.1	Articles of Incorporation of the Registrant and Amendments thereto.
*3.2	Bylaws of the Registrant.
%10.1	GulfWest Oil Company 1994 Stock Option and Compensation Plan, amended and restated as of April 1, 2001 and approved by the shareholders on May 18, 2001.
22.1	Subsidiaries of the Registrant (included on page 3 of this Annual Report.
25	Power of Attorney (included on signature page of this Annual Report).
31.1	Certification of Chief Executive Officer pursuant to Exchange Rule 13a-14(a) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002; filed herewith.
31.2	Certification of Chief Financial Officer pursuant to Exchange Rule 13a-14(a) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002; filed herewith.
32	Certification pursuant to 18.U.S.C Section 1350 pursuant to Section 906 of the Sarbanes-Oxley Act of 2002; filed herewith.

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* Previously filed with our Registration Statement (on Form S-1, Reg. No. 33-53526), filed with the Commission on October 21, 1992.

% Previously filed with our Proxy Statement on Form DEF 14A, filed with the Commission on April 16, 2001.

(b) Reports on Form 8-K.

None.

SIGNATURES

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

GULFWEST ENERGY INC.

Date: March 29, 2004

By \s\ Thomas R. Kaetzer
Thomas R. Kaetzer, President

POWER OF ATTORNEY

Know all men by these presents, that each person whose signature appears below constitutes and appoints Thomas R. Kaetzer as his true and lawful attorney-in-fact and agent, with full power of substitution, for him and in his name, place, and stead, in any and all capacities to sign any and all amendments or supplements to this Annual Report on Form 10-K, and to file the same, and with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

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

Signature	Title	Date
\s\ J. Virgil Waggoner J. Virgil Waggoner	Chairman of the Board	March 29, 2004
\s\ Thomas R. Kaetzer Thomas R. Kaetzer	President, Chief Executive Officer and Director	March 29, 2004
\s\ Jim C. Bigham Jim C. Bigham	Executive Vice President and Secretary	March 29, 2004
\s\ Richard L. Creel Richard L. Creel	Vice President of Finance, Controller	March 29, 2004
\s\ Marshall A. Smith III Marshall A. Smith III	Director	March 29, 2004
\s\ John E. Loehr John E. Loehr	Director	March 29, 2004
\s\ M. Scott Manolis M. Scott Manolis	Director	March 29, 2004

GULFWEST ENERGY INC.

FINANCIAL REPORT

DECEMBER 31, 2003

CONTENTS

All other Financial Statement Schedules have been omitted because they are either inapplicable or the information required is included in the financial statements or the notes thereto.

INDEPENDENT AUDITOR'S REPORT

To the Stockholders and
Board of Directors
GULFWEST ENERGY INC.

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

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

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

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As shown in the consolidated financial statements, the Company incurred a net loss of $3,151,509 during the year ended December 31, 2003, and, as of that date, had a working capital deficiency of $42,876,963. Those conditions raise substantial doubt about the Company's ability to continue as a going concern. Management's plans regarding those matters described in Note 2, "Operations and Management Plans". The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

As explained in Note 1 to the Financial Statements, effective January 1, 2003, the Company changed its accounting method for Asset Retirement Obligations.

\s\WEAVER AND TIDWELL, L.L.P
WEAVER AND TIDWELL, L.L.P.

Dallas, Texas
March 19, 2004

GULFWEST ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

DECEMBER 31, 2003 AND 2002

ASSETS

	2003	2002
CURRENT ASSETS		
Cash and cash equivalents	$ 483,618	$ 687,694
Accounts receivable – trade, net of allowance for doubtful accounts of $-0- in 2003 and 2002	1,099,802	1,361,446
Prepaid expenses	159,269	303,906
Total current assets	1,742,689	2,353,046
OIL AND GAS PROPERTIES, using the successful efforts method of accounting	58,472,886	56,786,043
OTHER PROPERTY AND EQUIPMENT	2,132,220	2,121,410
Less accumulated depreciation, depletion and amortization	(10,017,931)	(8,498,497)
Net oil and gas properties and other property and equipment	50,587,175	50,408,956
OTHER ASSETS		
Deposits	20,142	37,442
Debt issue cost, net	78,768	289,497
Total other assets	98,910	326,939
TOTAL ASSETS	$52,428,774	$53,088,941

The Notes to Consolidated Financial Statements are an integral part of these statements.

LIABILITIES AND STOCKHOLDERS' EQUITY

	2003	2002
CURRENT LIABILITES		
Notes payable	$ 8,182,165	$ 4,936,088
Notes payable – related parties	1,465,000	1,290,000
Current portion of long-term debt	29,396,092	33,128,447
Current portion of long-term debt – related parties	130,152	256,967
Accounts payable – trade	5,002,675	3,928,477
Accrued expenses	443,568	458,587
Total current liabilities	44,619,652	43,998,566
NONCURRENT LIABILITIES		
Long-term debt, net of current portion	35,801	126,552
Long-term debt – related parties	-	11,256
Asset retirement obligations	1,357,206	-
Total noncurrent liabilities	1,393,007	137,808
OTHER LIABILITES		
Derivative instruments	591,467	1,128,993
Total Liabilities	46,604,126	45,265,367
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY		
Preferred stock	190	170
Common stock	18,493	18,493
Additional paid-in capital	29,283,692	28,258,212
Retained deficit	(23,477,727)	(20,453,301)
Total stockholders' equity	5,824,648	7,823,574
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$52,428,774	$53,088,941

The Notes to Consolidated Financial Statements are an integral part of these statements.

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GULFWEST ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 AND 2001

	2003	2002	2001
OPERATING REVENUES			
Oil and gas sales	$ 10,844,460	$ 10,447,169	$ 12,426,103
Well servicing revenues		39,116	169,167
Operating overhead and other income	166,263	353,512	395,311
Total Operating Revenues	11,010,723	10,839,797	12,990,581
OPERATING EXPENSES			
Lease operating expenses	5,527,841	5,430,205	5,155,500
Cost of well servicing operations		56,295	182,180
Depreciation, depletion and amortization	2,226,123	2,697,784	2,491,385
Accretion expense	76,823		
General administrative	2,262,425	1,727,858	1,709,641
Total Operating Expenses	10,093,212	9,912,142	9,538,706
INCOME FROM OPERATIONS	917,511	927,655	3,451,875
OTHER INCOME AND EXPENSE			
Interest expense	(3,363,330)	(3,159,381)	(2,756,912)
Other financing costs	(1,000,000)		
Gain (loss) on sale of assets	(19,848)	(56,647)	(118,254)
Unrealized gain (loss) on derivative instruments	537,526	(1,596,575)	4,215,017
Dry holes, abandoned property and impaired assets	(358,737)	(617,365)	
Total Other Income and (Expense)	(4,204,389)	5,429,968	1,339,851
INCOME (LOSS) BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLES	(3,286,878)	(4,502,313)	4,791,726
INCOME TAXES			
INCOME (LOSS) BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLES	(3,286,878)	(4,502,313)	4,791,726
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLES, NET OF INCOME TAXES	262,452		(3,747,435)
NET INCOME (LOSS)	$ (3,024,426)	$ (4,502,313)	$ 1,044,291
DIVIDENDS ON PREFERRED STOCK (PAID 2003-$-0-; 2002-$112,500; 2001-$28,125)	(127,083)	(112,500)	(56,250)
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	$ (3,151,509)	$ (4,614,813)	$ 988,041
NET INCOME (LOSS) PER SHARE, BASIC BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLES	$ (.18)	$ (.25)	$ .25
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLES	.01		(.20)
NET INCOME (LOSS) PER SHARE BASIC	$ (.17)	$ (.25)	$ .05
NET INCOME (LOSS) PER SHARE, DILUTED BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLES	$ (.18)	$ (.25)	$ .23
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLES	.01		(.18)
NET INCOME (LOSS) PER SHARE, DILUTED	$ (.17)	$ (.25)	$ .05

GULFWEST ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 AND 2001

	Number of Shares	
	Preferred Stock	Common Stock
BALANCE, December 31, 2000	8,000	18,445,041
Issuance of 9,000 shares of Series E preferred stock for the acquisition of assets	9,000	
Issuance of 47,500 shares of common stock for the acquisition of assets		47,500
Issuance of warrants for the acquisition of assets		
Net income		
Dividends paid on preferred stock		
BALANCE, December 31, 2001	17,000	18,492,541
Issuance of warrants for additional financing		
Net loss		
Dividends paid on preferred stock		
BALANCE, December 31, 2002	17,000	18,492,541
Issuance of warrants for additional financing		
Issuance of preferred stock related to current financing	2,000	
Net loss		
BALANCE, December 31, 2003	19,000	18,492,541

The Notes to Consolidated Financials are an integral part of these statements.

Preferred Stock		Common Stock		Additional Paid-In Capital		Retained Deficit	
$	80	$	18,445	$	23,537,900	$	(16,854,654)
	90				4,499,910		
			48		35,402		
					91,500		
							1,044,291
							(28,125)
$	170	$	18,493	$	28,164,712	$	(15,838,488)
					93,500		
							(4,502,313)
							(112,500)
$	170	$	18,493	$	28,258,212	$	(20,453,301)
					25,500		
	20				999,980		
							(3,024,426)
$	190	$	18,493	$	29,283,692	$	(23,477,727)

The Notes to Consolidated Financials are an integral part of these statements.

GULFWEST ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 AND 2001

	2003	2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (3,024,426)	$ (4,502,313)	$ 1,044,291
Adjustments to reconcile net income (loss) to net cash			
Provided by operating activities:			
Depreciation, depletion and amortization	2,226,123	2,697,784	2,491,385
Accretion expense	76,823		
Common stock and warrants issued and charged to operations	25,500	93,500	
Other financing costs	1,000,000		
Loss on sale of assets	19,848	56,647	118,254
Dry holes, abandoned property, impaired assets	358,737	617,365	
Unrealized (gain) loss on derivative instruments	(537,526)	1,596,575	(4,215,017)
Cumulative effect of accounting change	(262,452)		3,747,435
Provision for bad debts	29,201		
(Increase) decrease in accounts receivable – trade, net	232,443	(109,437)	765,939
(Increase) decrease in prepaid expenses	144,637	(179,825)	(40,730)
Increase (decrease) in accounts payable and accrued expenses	1,235,503	1,043,994	797,800
Net cash provided by operating activities	1,524,411	1,314,290	4,709,357
CASH FLOWS FROM INVESTING ACTIVITIES:			
Deposits			(9,804)
Proceeds from sale of property and equipment	38,561	675,440	394,423
Purchase of property and equipment	(1,067,924)	(5,861,969)	(6,962,650)
Net cash used in investing activities	(1,029,363)	(5,186,529)	(6,578,031)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Payments on debt	(1,672,288)	(3,410,778)	(6,577,928)
Proceeds from debt issuance	973,164	7,394,181	8,530,269
Debt issue cost			(29,544)
Dividends paid		(112,500)	(28,125)
Net cash provided by (used in) financing activities	(699,124)	3,870,903	1,894,672
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(204,076)	(1,336)	25,998
CASH AND CASH EQUIVALENTS, Beginning of year	687,694	689,030	663,032
CASH AND CASH EQUIVALENTS, End of year	$ 483,618	$ 687,694	$ 689,030
CASH PAID FOR INTEREST	$ 3,216,034	$ 3,004,015	$ 2,811,677

The Notes to Consolidated Financial Statements are an integral part of these statements.

Note 1. Summary of Significant Accounting Policies

The following is a summary of the significant accounting policies consistently applied by management in the preparation of the accompanying consolidated financial statements.

Organization/Concentration of Credit Risk

GulfWest Energy Inc. and our subsidiaries intend to pursue the acquisition of quality oil and gas prospects, which have proved developed and undeveloped reserves and the development of prospects with third party industry partners.

The accompanying consolidated financial statements include our company and its wholly-owned subsidiaries: RigWest Well Service, Inc. ("RigWest"), GulfWest Texas Company ("GWT"), both formed in 1996; DutchWest Oil Company formed in 1997; SETEX Oil and Gas Company ("SETEX") formed August 11, 1998; Southeast Texas Oil and Gas Company, L.L.C. ("Setex LLC") acquired September 1, 1998; GulfWest Oil and Gas Company formed February 18, 1999; LTW Pipeline Co. formed April 19, 1999; GulfWest Development Company ("GWD") formed November 9, 2000 and GulfWest Oil and Gas Company (Louisiana) LLC, formed July 31, 2001. All material intercompany transactions and balances are eliminated upon consolidation.

We grant credit to independent and major oil and gas companies for the sale of crude oil and natural gas. In addition, we grant credit to joint owners of oil and gas properties, which we, through our subsidiary, SETEX, operate. Such amounts are secured by the underlying ownership interests in the properties. We also grant credit to various third parties through RigWest for well servicing operations.

We maintain cash on deposit in non-interest bearing accounts, which, at times, exceed federally insured limits. We have not experienced any losses on such accounts and believe we are not exposed to any significant credit risk on cash and equivalents.

Statement of Cash Flows

We consider all highly liquid investment instruments purchased with remaining maturities of three months or less to be cash equivalents for purposes of the consolidated statements of cash flows.

Non-Cash Investing and Financing Activities:

During the twelve month period ended December 31, 2003, we adopted Statement of Financial Accounting Standard No. 143 "Asset Retirement Obligations" (SFAS 143). As a result of adopting SFAS 143, effective January 1, 2003, we recorded an asset retirement obligation liability of $1,280,383, an increase in the carrying value of our oil and gas properties of $1,058,445, a reduction in accumulated depletion of $484,390 and an adjustment to prior income of $262,452. This liability was increased during 2003 by recognizing $76,823 in accretion expense. Also, we decreased the current portion of long term debt-related parties by applying $17,300 in deposits and reclassified $176,320 from accrued expenses to current portion of long term debt.

During the twelve month period ended December 31, 2002, we acquired $74,653 in property and equipment through notes payable to financial institutions. We also acquired $182,742 of oil producing properties in exchange of accounts receivable from a related party. In addition, we sold property and equipment, which included an account receivable of $42,000. This receivable was collected in January 2003.

Note 1. Summary of Significant Accounting Policies (continued)

Statement of Cash Flows – Non-cash Investing and Financing Activities – continued

During the twelve month period ended December 31, 2001, we acquired $15,068,774 in property and equipment through $10,441,824 in notes payable to financial institutions and related parties, by issuing 9,000 shares of preferred stock valued at $4,500,000, by issuing 47,500 shares of common stock valued at $35,450 and by issuing 150,000 warrants valued at $91,500. Also, debt issue costs increased $170,000 in notes payable.

Use of Estimates in the Preparation of Financial Statements

The preparation of consolidated financial statements in conformity with generally accepted accounting principles 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 consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Oil and Gas Properties

We use the successful efforts method of accounting for oil and gas producing activities. Costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, and geological and geophysical costs are expensed.

As we acquire significant oil and gas properties, any unproved property that is considered individually significant is periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. Capitalized costs of producing oil and gas properties and support equipment, after considering estimated dismantlement and abandonment costs and estimated salvage values, are depreciated and depleted by the unit-of-production method.

On the sale of an entire interest in an unproved property, gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property has been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained. On the sale of an entire or partial interest in a proved property, gain or loss is recognized, based upon the fair values of the interests sold and retained.

Other Property and Equipment

The following tables set forth certain information with respect to our other property and equipment. We provide for depreciation and amortization using the straight-line method over the following estimated useful lives of the respective assets:

Assets	Years
Automobiles	3-5
Office equipment	7
Gathering system	10
Well servicing equipment	10

Note 1. Summary of Significant Accounting Policies - continued

Other Property and Equipment – continued

Capitalized costs relating to other properties and equipment:

	2003	2002
Automobiles	$ 420,776	$ 420,776
Office equipment	148,172	137,362
Gathering system	529,486	529,486
Well servicing equipment	1,033,786	1,033,786
	2,132,220	2,121,410
Less accumulated depreciation	(1,268,330)	(1,037,076)
Net capitalized cost	$ 863,890	$ 1,084,334

Revenue Recognition

We recognize oil and gas revenues on the sales method as oil and gas production is sold. Differences between sales and production volumes during the years ended December 31, 2003, 2002, and 2001 were not significant. Well servicing revenues are recognized as the related services are performed. Operating overhead income is recognized based upon monthly contractual amounts for lease operations and other income is recognized as earned.

Trade Accounts Receivable

Trade accounts receivable are reported in the consolidated balance sheet at the outstanding principal adjusted for any chargeoffs. An allocation for doubtful accounts is recognized by management based upon a review of specific customer balances, historical losses and general economic conditions.

Fair Value of Financial Instruments

At December 31, 2003 and 2002, our financial instruments consist of notes payable and long-term debt. Interest rates currently available to us for notes payable and long-term debt with similar terms and remaining maturities are used to estimate fair value of such financial instruments. Accordingly, the carrying amounts are a reasonable estimate of fair value.

Debt Issue Costs

Debt issue costs incurred are capitalized and subsequently amortized over the term of the related debt on a straight-line basis.

Earnings (Loss) Per Share

Earnings (loss) per share are calculated based upon the weighted-average number of outstanding common shares. Diluted earnings (loss) per share are calculated based upon the weighted-average number of outstanding common shares, plus the effect of dilutive stock options, warrants, convertible preferred stock and convertible debentures.

Note 1. Summary of Significant Accounting Policies - continued

Earnings (Loss) Per Share - continued

We have adopted Statement of Financial Accounting Standards (SFAS) No. 128 "Earnings Per Share", which requires that both basic earnings (loss) per share and diluted earnings (loss) per share be presented on the face of the statement of operations. Basic earnings (loss) per share are based on the weighted-average number of outstanding common shares. Diluted earnings (loss) per-share are based on the weighted-average number of outstanding common shares and the effect of all potentially diluted common shares.

Impairments

Impairments, measured using fair market value, are recognized whenever events or changes in circumstances indicate that the carrying amount of long-lived assets (other than unproved oil and gas properties discussed above) may not be recoverable and the future undiscounted cash flows attributable to the asset are less than its carrying value.

Stock Based Compensation

In October 1995, SFAS No. 123, "Stock Based Compensation," (SFAS 123) was issued. This statement requires that we choose between two different methods of accounting for stock options and warrants. The statement defines a fair-value-based method of accounting for stock options and warrants but allows an entity to continue to measure compensation cost for stock options and warrants using the accounting prescribed by APB Opinion No. 25 (APB 25), "Accounting for Stock Issued to Employees." Use of the APB 25 accounting method results in no compensation cost being recognized if options are granted at an exercise price at the current market value of the stock or higher. We will continue to use the intrinsic value method under APB 25 but are required by SFAS 123 to make pro forma disclosures of net income (loss) and earnings (loss) per share as if the fair value method had been applied in its 2003, 2002 and 2001 financial statements.

During 2003, 2002 and 2001, we issued options and warrants totaling: 2003 – 35,000 (all exercisable); 2002 – 405,000 (all exercisable); and 2001 – 184,000 (all exercisable), respectively, to employees and directors as compensation. If we had used the fair value method required by SFAS 123, our net income (loss) and per share information would approximate the following amounts:

	2003		2002		2001	
	As Reported	ProForma	As Reported	ProForma	As Reported	ProForma
SFAS 123 compensation cost	$	$ 7,350	$	$ 38,300		$ 99,360
APB 25 compensation cost	$	$	$	$		$
Net income (loss)	$(3,151,509)	$(3,158,859)	$(4,614,813)	$ (4,653,113)	$ 988,041	$ 888,681
Income (loss) per common share–basic	$ (.17)	$ (.17)	$ (.25)	$ (.25)	$ .05	$ .05
Income (loss) per common share-diluted	$ (.17)	$ (.17)	$ (.25)	$ (.25)	$ .05	$ .04

Note 1. Summary of Significant Accounting Policies - continued

Stock Based Compensation - continued

The effects of applying SFAS 123 as disclosed above are not indicative of future amounts. We anticipate making additional stock based employee compensation awards in the future.

We use the Black-Sholes option-pricing model to estimate the fair value of the options and warrants (to employee and non-employees) on the grant date. Significant assumptions include (1) risk free interest rate 2003 – 3.0%; 2002 – 3.0%; 2001 – 4.5%; (2) weighted average expected life 2003 – 3.4; 2002 – 3.6; 2001 - 5.0; (3) expected volatility of 2003 – 147.43; 2002 – 101.73%; 2001 – 103.27%; and (4) no expected dividends.

Implementation of New Financial Accounting Standards

Effective January 1, 2001, we adopted SFAS No. 133 "Accounting for Derivative Instruments and Other Hedging Activities", as amended by SFAS No. 137 and No. 138. As a result of a financing agreement with an energy lender, we were required to enter into an oil and gas hedging agreement with the lender. It has been determined this agreement meets the definition of SFAS 133 "Accounting for Derivative Instruments and Hedging Activities" and is accounted for as a derivative instrument.

The estimated change in fair value of the derivatives is reported in Other Income and Expense as unrealized (gain) loss on derivative instruments. The estimated fair value of the derivatives is reported in Other Assets (or Other Liabilities) as derivative instruments.

The estimated fair value of the derivative instruments at January 1, 2001, the date of initial application of SFAS 133, of $3,747,435 is reported in the Statement of Operations as the cumulative effect of a change in accounting principle.

In June, 2001, SFAS No. 141 "Business Combinations" and SFAS No. 142 "Goodwill and Other Intangible Assets were issued. We presently have no goodwill or intangible assets and are thus not affected by SFAS No. 142.

Effective January 1, 2002, we adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." This statement requires the following three-step approach for assessing and recognizing the impairment of long-lived assets: (1) consider whether indicators of impairment of long-lived assets are present; (2) if indicators of impairment are present, determine whether the sum of the estimated undiscounted future cash flows attributable to the assets in question is less than their carrying amount; and (3) if less, recognize an impairment loss based on the excess of the carrying amount of the assets over their respective fair values. In addition, SFAS No. 144 provides more guidance on estimating cash flows when performing a recoverability test, requires that a long-lived asset to be disposed of other than by sale (such as abandoned) be classified as "held and used" until it is disposed of, and establishes more restrictive criteria to classify an asset as "held for sale". The adoption of SFAS No. 144 did not have a material impact on our financial statements since it retained the fundamental provisions of SFAS No. 121, "Accounting for the Impairment or Disposal of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," related to the recognition and measurement of the impairment of long-lived assets to be "held and used".

Note 1. Summary of Significant Accounting Policies - continued

Implementation of New Financial Accounting Standards - continued

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." SFAS No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred. Under EITF Issue No. 94-3, a liability for an exit cost as defined was recognized at the date of an entity's commitment to an exit plan. SFAS No. 146 also establishes that the fair value is the objective for the initial measurement of the liability. SFAS No. 146 is effective for exit and disposal activities that are initiated after December 31, 2002. This statement will impact the timing of our recognition of liabilities for costs associated with exit or disposal activities.

Beginning in 2003, Statement of Financial Accounting Standards No. 143, "Asset Retirement Obligations" ("SFAS 143") requires us to recognize an estimated liability for the plugging and abandonment of our oil and gas wells and associated pipelines and equipment. Consistent with industry practice, historically we had assumed the cost of plugging and abandonment would be offset by salvage value received. This statement requires us to record a liability in the period in which our asset retirement obligation ("ARO") is incurred. After initial recognition of the liability, we must capitalize an additional asset cost equal to the amount of the liability. In addition to any obligation that arises after the effective date of SFAS 143, upon initial adoption we must recognize (1) a liability for any existing ARO's, (2) capitalized cost related to the liability, and (3) accumulated depreciation, depletion and amortization on that capitalized cost adjusting for the salvage value of related equipment.

The estimated liability is based on historical experience in plugging and abandoning wells, estimated remaining lives of those wells based on reserves estimates and federal and state regulatory requirements. The liability is discounted using an assumed credit-adjusted risk-free rate of 7.5%. Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs, changes in the risk-free rate or remaining lives of the wells, or if federal or state regulators enact new plugging and abandonment requirements. At the time of abandonment, we will be required to recognize a gain or loss on abandonment if the actual costs do not equal the estimated costs.

The adoption of SFAS 143 resulted in a January 1, 2003 cumulative effect adjustment to record (i) a $1,058,445 increase in the carrying value of proved properties, (ii) a $484,390 decrease in accumulated depreciation, depletion and amortization, (iii) a $1,280,383 increase in noncurrent liabilities, and (iv) a $262,452 gain, net of tax.

Note 2. Operations and Management Plans

At December 31, 2003, our current liabilities exceeded our current assets by $42,876,963. We had a loss available to common shareholders of $3,151,509 compared to a loss available to common shareholders of $4,614,813 at December 31, 2002. This loss included non-cash items of $537,526 for unrealized gain on derivative instruments, a loss of $358,737 for abandonment of properties and a $262,452 gain from the recording of Asset Retirement Obligations ("ARO's"), as required by SFAS 143, at January 1, 2003.

In 2004, we will continue the recapitalization of debt and funding of our capital development program that we began in 2003. Following are the steps we are taking and plan to take to achieve that purpose:

Note 2. Operations and Management Plans - continued

(a) The first step is to close the refinancing of our largest debt of $27.8 million held by Concert Capital Resources LP ("CCR") and loaned to our wholly-owned subsidiary, GulfWest Oil & Gas Company. We have entered into an agreement with a new lending source that, subject to due diligence, will fund approximately $14 million to purchase the $27.8 million note. The new debt financing will also provide for the payment of closing costs. CCR has agreed to sell the note to our new financier for a $14 million cash payment and a $4 million subordinated note from us.

(b) Secondly, we are continuing to work with our financial advisor to raise an additional $4 to $5 million through the sale of our preferred stock. Proceeds from this equity sale will be used for working capital and fund our new development projects. The refinancing of the CCR debt and sale of new equity are both currently scheduled to close in April, 2004.

(c) Effective December 1, 2001 and amended August 16, 2002, we entered into an Oil and Gas Property Acquisition, Exploration and Development Agreement (the "Summit Agreement") with Summit Investment Group-Texas, L.L.C., an unrelated party, ("Summit"). Under the agreement, Summit provided payments in the aggregate of $1,200,000 in advanced funds for our use in the acquisition of oil and gas leases and other mineral and royalty interests, and production activities, and was to recoup and recover those advanced funds.

In a subsequent event on March 5, 2004, we entered into an Option Agreement for the Purchase of Oil and Gas Leases (the "Addison Agreement") with W. L. Addison Investments L.L.C., a private company owned by Mr. J. Virgil Waggoner and Mr. John E. Loehr, two of our directors, ('Addison"). Under the Addison Agreement, Addison agreed to pay Summit, on our behalf, the non-recouped and outstanding advanced funds amounting to $1,200,000, thereby retiring the Summit Agreement. For consideration of such payment, Addison acquired certain oil and gas leases and wellbores from Summit but agreed to grant us a 180-day redemption option (which may be extended by mutual consent) to purchase the same for $1,200,000, plus interest at the prime rate plus 2%. We tendered Addison a promissory note in the amount of $600,000, with interest at the prime rate plus 2%, to substitute for an account payable to Summit, pursuant to the Summit Agreement, in the same amount. The note will be considered paid in full if we exercise the redemption option and pay the $1,200,000, plus interest. Summit retained the right to participate up to a 25% *working interest* in the drilling of any wells on the leases acquired by Addison. In the event we exercise the redemption option, Addison may, at its sole option, retain up to a 25% *working interest* in the leases.

(d) Finally, after completing the above, we will pursue the consolidation of all of our debt, including other asset and bridge loans. Our goal is to simplify our financial structure and provide adequate capitalization for the development of our oil and gas assets.

GULFWEST ENERGY INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 3. Cost of Oil and Gas Properties

The following tables set forth certain information with respect to our oil and gas producing activities for the periods presented:

Capitalized Costs Relating to Oil and Gas Producing Activities:

	2003	2002
Unproved oil and gas properties	$ 261,650	$ 439,926
Proved oil and gas properties	54,669,482	52,847,625
Support equipment and facilities	3,541,754	3,498,492
	58,472,886	56,786,043
Less accumulated depreciation, depletion and		
Amortization	(8,749,601)	(7,461,421)
Net capitalized costs	$ 49,723,285	$ 49,324,622

Results of Operations for Oil and Gas Producing Activities:

	2003	2002	2001
Oil and gas sales	$ 10,844,466	$ 10,447,169	$ 12,426,103
Production costs	(5,527,841)	(5,430,205)	(5,155,500)
Depreciation, depletion and amortization	(1,527,727)	(2,187,036)	(2,018,890)
Accretion expense	(76,823)		
Income tax expense	-	-	–
Results of operations for oil and gas producing activities - income	$ 3,712,075	$ 2,829,928	$ 5,251,713

Costs Incurred in Oil and Gas Producing Activities:

	2003	2002	2001
Property Acquisitions			
Proved	$ -	$ 562,760	$ 15,236,808
Unproved	110,119	14,401	154,076
Development Costs	2,024,663	5,141,075	6,317,527
	$ 2,134,782	$ 5,718,236	$ 21,708,411

Note 3. Cost of Oil and Gas Properties - continued

Effective July 1, 2001, we acquired interests in oil and gas properties located in Texas and Louisiana from an unrelated party, Grand Goldking L.L.C. The acquisition cost was $15,077,358, consisting of 9,000 shares of Series E preferred stock valued at $4,500,000 and $10,000,000 in debt. In addition, we paid $545,300 in commissions to unrelated parties. The commissions were paid by issuing 10,000 shares of common stock valued at $8,800, 150,000 warrants valued at $91,500 and $445,000 in cash. We incurred additional cash costs of $33,058 related to the acquisition. On the same date, we transferred its ownership interest in these properties to our wholly owned subsidiary, GulfWest Oil and Gas Company.

Supplemental unaudited pro forma information (under the purchase method of accounting) presenting the results of operations for the year ended December 31, 2001, as if the Grand Goldking acquisition had occurred as of January 1, 2001:

	Year Ended December 31, 2001
Operating revenues	$ 15,649,329
Operating expenses	10,652,222
Income from operations	4,997,107
Other income and expense	(3,325,166)
Income taxes	-
Net income	1,671,941
Preferred dividends	(112,500)
Net income to common shareholders	$ 1,559,441
Earnings per share	
Basic	$ 0.08
Diluted	$ 0.07

Effective January 1, 2002, we acquired oil and gas properties located in Louisiana from a related party for $182,742. The acquisition price was the amount of accounts receivable due us.

Note 4. Accrued Expenses

Accrued expenses consisted of the following:

	December 31, 2003	December 31, 2002
Payroll and payroll taxes	$ 5,833	$ 1,863
Interest	395,735	414,724
Professional fees	42,000	42,000
	$ 443,568	$ 458,587

Note 5. Notes Payable and Long-Term Debt

Notes payable is as follows:

	2003	2002
Non-interest bearing note payable to an unrelated party; payable out of 50% of the net transportation revenues from a certain natural gas pipeline; no due date.	$ 40,300	$ 40,300
Promissory note payable to a former director at 8%; due May, 2001; unsecured.	40,000	40,000
Promissory note payable to an unrelated party at 10%; payable on demand; unsecured.	45,000	45,000
Line of credit (up to $2,500,000) to a bank; due October, 2002; secured by guaranty of a director; interest greater of prime rate less .25% or 5.25%, (prime rate 4.0% at December 31, 2003). Line of credit increased to $3,000,000 and due date extended to April, 2004.	2,995,488	2,995,488
Note payable to a bank; due March, 2003; interest at prime rate plus 1% (prime rate 4.0% at December 31, 2003); secured by guaranty of three of our directors; retired September 2003.		500,000
Promissory note payable to an unrelated party; payable on demand; interest at 8%; interest increased to 12% on January 1, 2003; secured by certain oil and gas properties.	300,000	300,000
Note payable to a bank; due July, 2004; secured by guaranty of a director; interest at prime rate (prime rate 4.0% at December 31, 2003 with a floor of 4.75% and a ceiling of 8.0%.	948,400	1,000,000
Promissory note payable to unrelated party; interest at 6%; due June, 2003.	55,300	55,300
Promissory note payable to one of our directors; interest at 8%; due on demand; unsecured.	50,000	50,000
Promissory note payable to one of our directors; interest at prime rate (prime rate 4.0% at December 31, 2003); due May, 2003; secured by common stock of DutchWest Oil Company, our wholly owned subsidiary.	1,375,000	1,200,000
Promissory note payable to an unrelated party at 8%; due June 2003; secured by 4% of the common stock of DutchWest Oil Company, our wholly owned subsidiary	100,000	
Promissory note payable to an unrelated party at 8%; due May 2003; secured by 8% of the common stock of DutchWest Oil Company, our wholly owned subsidiary	200,000	

Note 5. Notes Payable and Long-Term Debt

Notes payable is as follows – continued:

	2003	2002
Line of credit (up to $3,500,000) to a bank; due June 2004; secured by the guaranty of a director; interest at prime rate (prime rate 4.0% at December 31, 2003) with a floor of 4.75% and a ceiling of 8.0%	3,497,677	
	$ 9,647,165	$ 6,226,088

The weighted average interest rate for notes payable at December 31, 2003 and 2002 was 5.0% and 4.7%, respectively.

Long-term debt is as follows:

	2003	2002
Line of credit (up to $3,000,000) to a bank; due July, 2003; secured by the guaranty of a director; interest at prime rate (prime rate 4.0% at December 31, 2003); replaced by a short-term line of credit (up to $3,500,000) from the same bank.	$	$ 2,999,515
Subordinated promissory notes to various individuals at 9.5% interest per annum; amounts include $50,000 due to related parties; past due.	150,000	150,000
Notes payable to finance vehicles, payable in aggregate monthly installments of approximately $4,000, including interest of.9% to 13% per annum; secured by the related equipment; due various dates through 2007.	69,500	116,721
Note payable to related party to finance equipment with monthly installments of $5,200, including interest at 13.76% per annum; final payment due October, 2003; secured by related equipment; retired June, 2003.		48,850
Promissory note to a director; interest at 8.5%; due December 31, 2003.	78,941	95,670
Note payable to a bank with monthly principal payments of $2,300; interest at 9.5%; due May, 2003; secured by related equipment; retired May, 2003.		11,630
Note payable to an energy lender; interest at prime plus 3.5% (prime rate 4.0% at December 31, 2003) payable monthly out of 90% net profits from certain oil and gas properties; final payment due May, 2004; secured by related oil and gas properties.	27,574,769	27,907,509

Note 5. Notes Payable and Long-Term Debt

Long-term debt is as follows – continued:

	2003	2002
Note payable to a bank with monthly principal payments of $36,000; interest at prime plus 1% (prime rate 4.0% at December 31, 2003) with a minimum prime rate of 5.5%; final payment due November, 2003; secured by related oil and gas properties; extended to March, 2004.	1,564,000	1,996,000
Note payable to unrelated party to finance saltwater disposal well with monthly installments of $4,540, including interest at 10% per annum; final payment due January, 2005; secured by related well.	123,624	123,624
Note payable to related party to finance equipment with monthly installments of $5,109, including interest at 13.75% per annum; final payment due February, 2004; secured by related equipment; retired June, 2003.		65,743
Note payable to related party to finance equipment with monthly installments of $608, including interest at 11% per annum; final payment due February, 2004; secured by related equipment.	1,211	7,960
	29,562,045	33,523,222
Less current portion	(29,526,244)	(33,385,414)
Total long-term debt	$ 35,801	$ 137,808

Estimated annual maturities for long-term debt are as follows:

2004	$ 29,526,244
2005	27,292
2006	7,150
2007	1,359
2008	-
	$ 29,562,045

Note 6. Stockholders' Equity

Common Stock

	2003	2002
Par value $.001; 40,000,000 shares authorized; 18,492,541 shares issued and outstanding as of December 31, 2003 and 2002, respectively	$ 18,493	$ 18,493

Preferred Stock

	2003	2002
Series D, par value $.01; 12,000 shares authorized; 8,000 shares issued and outstanding at December 31, 2003 and 2002. The Series D preferred stock does not pay dividends and is not redeemable. The liquidation value is $500 per share. After three years from the date of issue, and thereafter, the shares are convertible to common stock based upon a value of $500 per Series D share divided by $8 per share of common stock.	80	80
Series E, par value $.01; 9,000 shares authorized; 9,000 shares issued and outstanding at December 31, 2003 and 2002. The Series E preferred stock pays dividends, as declared, at a rate of 2.5% per annum, has a liquidation value of $500 per share, may be redeemed at our option and, if not redeemed after two years, is convertible to common stock based upon a value of $500 per Series E share divided by $2 per share of common stock.	90	90
Series F, par value $.01; 2,000 shares authorized; 2,000 shares issued and outstanding at December 31, 2003. The Series F preferred stock pays dividends, as declared, at a rate of 2.5% per annum, has a liquidation value of $500 per share, may be redeemed at our option and, if not redeemed after two years, is convertible to common stock based upon a value of $500 per Series E share divided by $1 per share of common stock.	20	
	$ 190	170

All classes of preferred shareholders have liquidation preference over common shareholders of $500 per preferred share, plus accrued dividends. Dividends in arrears at December 31, 2003 we $127,083 (Series E $112,500; Series F $14,583).

Stock Options

We maintain a Non-Qualified Stock Option Plan (as amended and restated, the "Plan"), which authorizes the grant of options of up to 2,000,000 shares of common stock. Under the Plan, options may be granted to any of our key employees (including officers), employee and nonemployee directors, and advisors. A committee appointed by the Board administers the Plan. Prior to 1999, options granted under the Plan had been granted at an option price of $3.13 and $1.81 per share. In July 1999, the Board authorized that all then current employee and director options under the plan be reduced to a price of $.75 per share. Following is a schedule by year of the activity related to stock options, including weighted-average ("WTD AVG") exercise prices of options in each category.

Note 6. Stockholders' Equity – continued

	2003		2002		2001	
	Wtd Avg Prices	Number	Wtd Avg Prices	Number	Wtd Avg Prices	Number
Balance, January 1	$ .90	1,067,000	$ 1.03	1,097,000	$ .09	923,000
Options issued	$ .75	35,000	$ .75	35,000	$ .83	184,000
Options expired	$ -	-	$ 3.00	(65,000)	$ 3.00	(10,000)
Balance, December 31	$ .90	1,102,000	$ .90	1,067,000	$ 1.03	1,097,000

All options were exercisable at December 31, 2003. Following is a schedule by year and by exercise price of the expiration of our stock options issued as of December 31, 2003:

	2004	2005	2006	2007	Thereafter	Total
$ .75	432,000			35,000	185,000	652,000
$ .83			184,000			184,000
$1.13		100,000				100,000
$1.20		106,000				106,000
$1.81					60,000	60,000
	432,000	206,000	184,000	35,000	210,000	1,102,000

Stock Warrants

We have issued a significant number of stock warrants for a variety of reasons, including compensation to employees, additional inducements to purchase our common or preferred stock, inducements related to the issuance of debt and for payment of goods and services. Following is a schedule by year of the activity related to stock warrants, including weighted-average exercise prices of warrants in each category:

	2003		2002		2001	
	Wtd Avg Prices	Number	Wtd Avg Prices	Number	Wtd Avg Prices	Number
Balance, January 1	$ 1.24	2,181,754	$ 2.15	1,306,754	$ 2.31	1,392,254
Warrants issued	$ .75	150,000	$ .75	1,145,000	$ .75	150,000
Warrants exercised or expired	$(3.61)	(366,754)	$ 3.57	(270,000)	$ 2.22	(235,500)
Balance, December 31	$ .76	1,965,000	$ 1.24	2,181,754	$ 2.15	1,306,754

Included in the "warrants issued" and "warrants exercised/expired" columns in 2002 were 270,000 warrants whose price was reduced in 2002 to $.75.

Note 6. Stockholders' Equity – continued

Following is a schedule by year and by exercise price of the expiration of our stock warrants issued as of December 31, 2003:

	2004	2005	2006	2007	2008	Total
$ .75		225,000	1,590,000			1,815,000
.875		150,000				150,000
	-	375,000	1,590,000	-	-	1,965,000

Warrants outstanding to our officers, directors and employees at December 31, 2003 and 2002 were approximately 1,515,000 and 1,682,000, respectively. The exercise prices on these warrants range from $.75 to $.88 and expire various dates through 2006.

Note 7. Income (Loss) Per Common Share

The following is a reconciliation of the numerators and denominators used in computing income (loss) per share:

	2003	2002	2001
Net income (loss)	$ (3,024,426)	$ (4,502,313)	$ 1,044,291
Preferred stock dividends	(127,083)	(112,500)	(56,250)
Income (loss) available to common shareholders (numerator)	$ (3,151,509)	$ (4,614,813)	$ 988,041
Weighted-average number of shares of common stock – basic (denominator)	18,492,541	18,492,541	18,464,343
Income (loss) per share - basic	$ (.17)	$ (.25)	$ .05

Potential dilutive securities (stock options, stock warrants and convertible preferred stock) in 2003 and 2002 have not been considered since we reported a net loss and, accordingly, their effects would be antidilutive. Potential dilutive securities (stock options, stock warrants and convertible preferred stock) totaling 2,780,520 weighted average shares in 2001 have been considered but there is no effect on income per common share.

Note 8. Related Party Transactions

On December 1, 1992, Ray Holifield and Associates, Inc. executed an unsecured promissory note to us for $118,645 with interest at 10% per annum, due on October 1, 1993. At December 31, 1993, the note was still outstanding. During 1994, we entered into an agreement with the Holifield Trust in which Holifield will make payments on the past due note from future oil and gas revenue. During 1995, $10,995 of interest payments were received. At December 31, 2001 the unsecured promissory note had been fully reserved. At December 31, 2002, the unsecured promissory note had been fully written off.

On December 1, 1992, Parkway Petroleum Company, a Ray Holifield related company, executed an unsecured promissory note to us for $54,616 with interest at 10% per annum, due on October 1, 1993. The note was issued for amounts due from contract drilling services we provided Parkway Petroleum Company. At December 31, 1993, the note was still outstanding. During 1994, we entered into an agreement with the Holifield Trust in which Holifield will make payments on the past due note from future oil and gas revenue. During 1995, Note 8. Related Party Transactions - continued

$6,250 of interest payments were received. At December 31, 2001, the unsecured promissory note had been fully reserved. At December 31, 2002, the unsecured promissory note had been fully written off.

On January 10, 1994, we entered into a consulting agreement with Williams Southwest Drilling Company, Inc. ("Williams") whereby we would provide management and accounting services for $25,000 per month for a period of one year. We accrued the consulting fees with an offset to deferred income until payment of the fees is actually received. During 1994, $172,140 was recorded as consulting fee income. Beginning in the second quarter 1994, we began recognizing consulting income only as cash payments were received. Prior to the second quarter, $75,000 in consulting fee revenue was accrued. We received $97,140 in consulting fee payments. As of December 31, 1994, the receivable from Williams of $202,860 for consulting fees has been offset by deferred income of $127,860 and a provision for doubtful accounts of $75,000. Effective January 1, 1995, we received a promissory note from Williams in the amount of $202,860, bearing interest at the rate of 10% per annum, and payable in quarterly installments of principal and interest of $15,538.87. At December 31, 2001, the unsecured promissory note had been fully reserved. At December 31, 2002, the unsecured promissory note had been fully written off.

From July 22 to August 13, 1998, we advanced sums totaling $102,000 to Gulf Coast Exploration, Inc. At December 31, 2001, the debt had been fully reserved. At December 31, 2002, the debt had been fully written off.

On October 1, 1998, Toro Oil Company executed an unsecured promissory note to us for the purchase of 100% of WestCo for $150,000, with interest at the prime rate per annum and due September 30, 1999. To date, no principal payments have been received. At December 31, 2001, the promissory note had been fully reserved. At December 31, 2002, the debt had been fully written off.

In a subsequent event on March 5, 2004, we entered into an Option Agreement for the Purchase of Oil and Gas Leases (the "Addison Agreement") with W. L. Addison Investments L.L.C., a private company owned by Mr. J. Virgil Waggoner and Mr. John E. Loehr, two of our directors, ('Addison"). Effective December 1, 2001 and amended August 16, 2002, we had entered into an Oil and Gas Property Acquisition, Exploration and Development Agreement (the "Summit Agreement") with Summit Investment Group-Texas, L.L.C., an unrelated party, ("Summit"). Under the agreement, Summit provided payments in the aggregate of $1,200,000 in advanced funds for our use in the acquisition of oil and gas leases and other mineral and royalty interests, and production activities, and was to recoup and recover those advanced funds. Under the Addison Agreement, Addison agreed to pay Summit, on our behalf, the non-recouped and outstanding advanced funds amounting to $1,200,000, thereby retiring the Summit Agreement. For consideration of such payment, Addison acquired certain oil and gas leases and wellbores from Summit but agreed to grant us a 180-day redemption option (which may be extended by mutual consent) to purchase the same for $1,200,000, plus interest at the prime rate plus 2%. We tendered Addison a promissory note in the amount of $600,000, with interest at the prime rate plus 2%, to substitute for an account payable due to Summit, pursuant to the Summit Agreement, in the same amount. The note will be considered paid in full if we exercise the redemption option and pay the $1,200,000, plus interest. Summit retained the right to participate up to a 25% *working interest* in the drilling of any wells on the leases acquired by Addison. In the event we exercise the redemption option, Addison may, at its sole option, retain up to a 25% *working interest* in the leases.

Interest expensed on related party notes totaled approximately $76,000, $53,000 and $128,000 for the years ended December 31, 2003, 2002 and 2001 respectively.

Note 9. Income Taxes

The components of the net deferred federal income tax assets (liabilities) recognized in our consolidated balance sheets were as follows::

Note 9. Income Taxes – continued

	December 31, 2003	December 31, 2002
Deferred tax assets		
Net operating loss carryforwards	$ 6,352,507	$ 5,236,485
Oil and gas properties	610,381	542,131
Capital loss carryforwards	-	93,211
Derivative instruments	201,099	383,858
Accretion	26,120	
Net deferred tax assets before valuation allowance	7,190,107	6,255,685
Valuation allowance	(7,190,107)	(6,255,685)
Net deferred tax assets (liabilities)	$ -	$ -

As of December 31, 2003 and 2002, we did not believe it was more likely than not that the net operating loss carryforwards would be realizable through generation of future taxable income; therefore, they were fully reserved.

The following table summarizes the difference between the actual tax provision and the amounts obtained by applying the statutory tax rate of 34% to the income (loss) before income taxes for the years ended December 31, 2003, 2002 and 2001.

	2003	2002	2001
Tax (benefit) calculated at statutory rate	$ (1,028,305)	$ (1,530,786)	$ 355,059
Increase (reductions) in taxes due to:			
Effect on non-deductible expenses	362,910	65,174	18,157
Change in valuation allowance	934,422	1,586,988	(345,754)
Other	(269,027)	(121,376)	(27,462)
Current federal income tax provision	$ -	$ -	$ -

As of December 31, 2003 we had net operating loss carryforwards of approximately $18,700,000, which are available to reduce future taxable income and capital gains, respectively, and the related income tax liability. The net operating loss carryforward expires at various dates through 2023.

Note 10. Commitments and Contingencies

Oil and Gas Hedging Activities

We entered into an agreement with an energy lender commencing in May, 2000, to hedge a portion of our oil and gas sales for the period of May, 2000 through April, 2004. The agreement called for initial volumes of 7,900 barrels of oil and 52,400 Mmbtu of gas per month, declining monthly thereafter. We entered into a second agreement with the energy lender, commencing September, 2001, to hedge an additional portion of our oil and gas sales for the periods of September, 2001 through July, 2004 and September, 2001 through December 2002, respectively. The agreement called for initial volumes of 15,000 barrels of oil and 50,000 Mmbtu of gas per month, declining monthly thereafter. Volumes at December 31, 2003 had declined to 6,400 barrels of oil and

Note 10. Commitments and Contingencies – continued

21,200 Mmbtu of gas. As a result of these agreements, we realized a reduction in revenues of $1,496,303, $368,776 and $762,480 for the twelve-month periods ended December 31, 2003, 2002 and 2001, respectively, which is included in oil and gas sales.

Lease Obligations

We lease office space at one location under a sixty-four (64) month lease, which commenced December 1, 2001 and was amended May 30, 2002 after expansion. Annual commitments under the lease are: 2004 – $130,050, 2005 – $132,979, 2006 - $135,323 and 2007 - $33,977. Total rent expense for the years ended December 31, 2003, 2002 and 2001 were approximately $134,500, $91,000 and $60,000, respectively.

Litigation

From time to time, we are involved in litigation arising out of our operations or from disputes with vendors in the normal course of business. As of March 29, 2004, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material effect on our consolidated financial statements.

Note 11. Oil and Gas Reserves Information (Unaudited)

The estimates of proved oil and gas reserves utilized in the preparation of the financial statements are estimated in accordance with guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations over prices and costs existing at year end except by contractual arrangements.

We emphasize that reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. Our policy is to amortize capitalized oil and gas costs on the unit of production method, based upon these reserve estimates. It is reasonably possible that, because of changes in market conditions or the inherent imprecision of these reserve estimates, that the estimates of future cash inflows, future gross revenues, the amount of oil and gas reserves, the remaining estimated lives of the oil and gas properties, or any combination of the above may be increased or reduced in the near term. If reduced, the carrying amount of capitalized oil and gas properties may be reduced materially in the near term.

GULFWEST ENERGY INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 11. Oil and Gas Reserves Information (Unaudited) - continued

The following unaudited table sets forth proved oil and gas reserves, all within the United States, at December 31, 2003, 2002, and 2001, together with the changes therein.

	Crude Oil (BBls)	Natural Gas (*Mcf*)
QUANTITIES OF PROVED RESERVES:		
Balance December 31, 2000	4,575,179	24,811,919
Revisions	(386,078)	238,595
Extensions, discoveries and additions	5,676	895,333
Purchase	2,078,561	14,905,837
Sales	(107,225)	1,122
Production	(294,276)	(1,594,899)
Balance December 31, 2001	5,871,837	39,257,907
Revisions	(125,468)	(4,959,229)
Extensions, discoveries and additions	22,129	1,090,024
Purchase	52,480	1,090,025
Sales	(20,698)	(837,856)
Production	(278,374)	(1,487,048)
Balance December 31, 2002	5,521,906	34,158,823
Revisions	(262,608)	(308,080)
Extensions, discoveries and additions	-	-
Purchase	-	-
Sales	-	-
Production	(221,335)	(1,190,624)
Balance December 31, 2003	5,037,963	32,660,119
PROVED DEVELOPED RESERVES:		
December 31, 2001	3,939,593	21,203,989
December 31, 2002	4,025,552	25,374,113
December 31, 2003	3,772,926	24,642,407

Note 11. Oil and Gas Reserves Information (Unaudited) - continued

STANDARDIZED MEASURE:

Standardized measure of discounted future net cash flows relating to proved reserves:

	2003	2002	2001
Future cash inflows	$ 336,795,385	$ 308,381,837	$ 199,162,921
Future production and development costs			
Production	109,468,727	105,629,872	77,526,278
Development	21,460,459	23,350,811	23,610,596
Future cash flows before income taxes	205,866,199	179,401,154	98,026,047
Future income taxes	(46,885,360)	(38,611,577)	(13,281,358)
Future net cash flows after income taxes	158,980,839	140,789,577	84,744,689
10% annual discount for estimated timing of cash flows	(70,653,419)	(63,165,742)	(35,895,306)
Standardized measure of discounted future net cash flows	$ 88,327,420	$ 77,623,835	$ 48,849,383

The following reconciles the change in the standardized measure of discounted future net cash flows:

	2003	2002	2001
Beginning of year	$ 77,623,835	$ 48,849,383	$ 90,381,127
Changes from:			
Purchases	-	3,054,793	27,032,359
Sales	-	(953,159)	(443,324)
Extensions, discoveries and improved recovery, less related costs	-	2,002,176	427,192
Sales of oil and gas produced net of production costs	(5,316,619)	(5,016,964)	(7,270,603)
Revision of quantity estimates	(3,751,921)	(9,974,557)	(1,783,276)
Accretion of discount	9,889,881	5,649,945	12,414,073
Change in income taxes	(4,793,281)	(13,624,917)	26,109,535
Changes in estimated future development costs	2,003,801	(5,254,561)	(6,360,990)
Development costs incurred that reduced future development costs	2,024,663	5,569,881	5,945,369
Change in sales and transfer prices, net of production costs	16,470,113	46,903,282	(89,573,528)
Changes in production rates (timing) and other	(5,823,052)	418,533	(8,028,551)
End of year	$ 88,327,420	$ 77,623,835	$ 48,849,383

GULFWEST ENERGY INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 12. Quarterly Results (Unaudited)

Summary data relating to the results of operations for each quarter for the years ended December 31, 2003 and 2002 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
2003				
Net sales	$ 3,250,603	$ 2,790,124	$ 2,436,063	$ 2,533,933
Gross profit	862,683	406,576	81,573	(433,321)
Net income (loss)	120,659	(1,231,883)	(399,457)	(1,640,828)
Income (loss) per common share – basic and diluted	$ .01	$ (.07)	$ (.02)	$ (.09)
2002				
Net sales	$ 2,648,873	$ 2,951,798	$ 2,641,626	$ 2,597,500
Gross profit	239,912	450,255	100,527	136,961
Net income (loss)	(1,964,010)	(305,060)	(924,750)	(1,420,993)
Income (loss) per common share – basic and diluted	$ (0.11)	$ (0.02)	$ (0.05)	$ (0.07)

INDEPENDENT AUDITOR'S REPORT

Stockholders and Board of Directors
GULFWEST ENERGY INC.

Our report on the consolidated financial statements of GulfWest Energy Inc. and Subsidiaries as of December 31, 2003 and 2002 and for each of the three years in the period ended December 31, 2003, is included on page F-1. In connection with our audit of such consolidated financial statements, we have also audited the related financial statement schedule for the years ended December 31, 2003, 2002 and 2001 on page F-31.

In our opinion, the financial statement schedule referred to above, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information required to be included therein.

\s\ WEAVER AND TIDWELL, L.L.P.
WEAVER AND TIDWELL, L.L.P.

Dallas, Texas
March 19, 2004

GULFWEST ENERGY INC. AND SUBSIDIARIES
SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 AND 2001

DECRIPTION	BALANCE AT BEGINNING OF PERIOD	PROVISIONS/ ADDITIONS	RECOVERIES/ DEDUCTIONS	BALANCE AT END OF PERIOD
For the year ended				
December 31, 2001				
Accounts and notes receivable related parties	$ 740,478	$	$	$ 740,478
Valuation allowance for deferred tax assets	$ 5,014,451	$ (345,754)	$	$ 4,668,697
For the year ended				
December 31, 2002				
Accounts and notes receivable related parties	$ 740,478	$	$ (740,478)	$
Valuation allowance for deferred tax assets	$ 4,668,697	$ 1,586,988	$	$ 6,255,685
For the year ended				
December 31, 2003				
Valuation allowance for deferred tax assets	$ 6,255,685	$ 934,422		$ 7,190,107

Board of Directors

J. Virgil Waggoner
Chairman of the Board

Thomas R. Kaetzer

John E. Loehr

Marshall A. Smith III

M. Scott Manolis

Officers

John E. Loehr
Chief Executive Officer

Thomas R. Kaetzer
President and Chief Operating Officer

Jim C. Bigham
Executive Vice President and Secretary

Richard L. Creel
Vice President of Finance and Controller

Corporate Information

Corporate Office: GulfWest Energy Inc.
480 N. Sam Houston Parkway E.
Suite 300
Houston, Texas 77060
(281) 820-1919

Transfer Agent: Fidelity Transfer Company
1800 South West Temple
Suite 301, Box 53
Salt Lake City, Utah 84115

Auditors: Weaver & Tidwell, L.L.P.
Three Forest Plaza
12221 Merit Drive, Suite 1700
Dallas, Texas 75251

Common Stock Information: The Common Stock is traded over the counter under the symbol "GULF".

Form 10-K: Additional copies of the Company's Form 10-K as filed with the Securities and Exchange Commission are available without charge by writing to Mr. Jim C. Bigham, Secretary, GulfWest Energy Inc., 480 N. Sam Houston Parkway E., Suite 300, Houston, Texas 77060.