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KCS Energy, Inc.

Annual Report 2002

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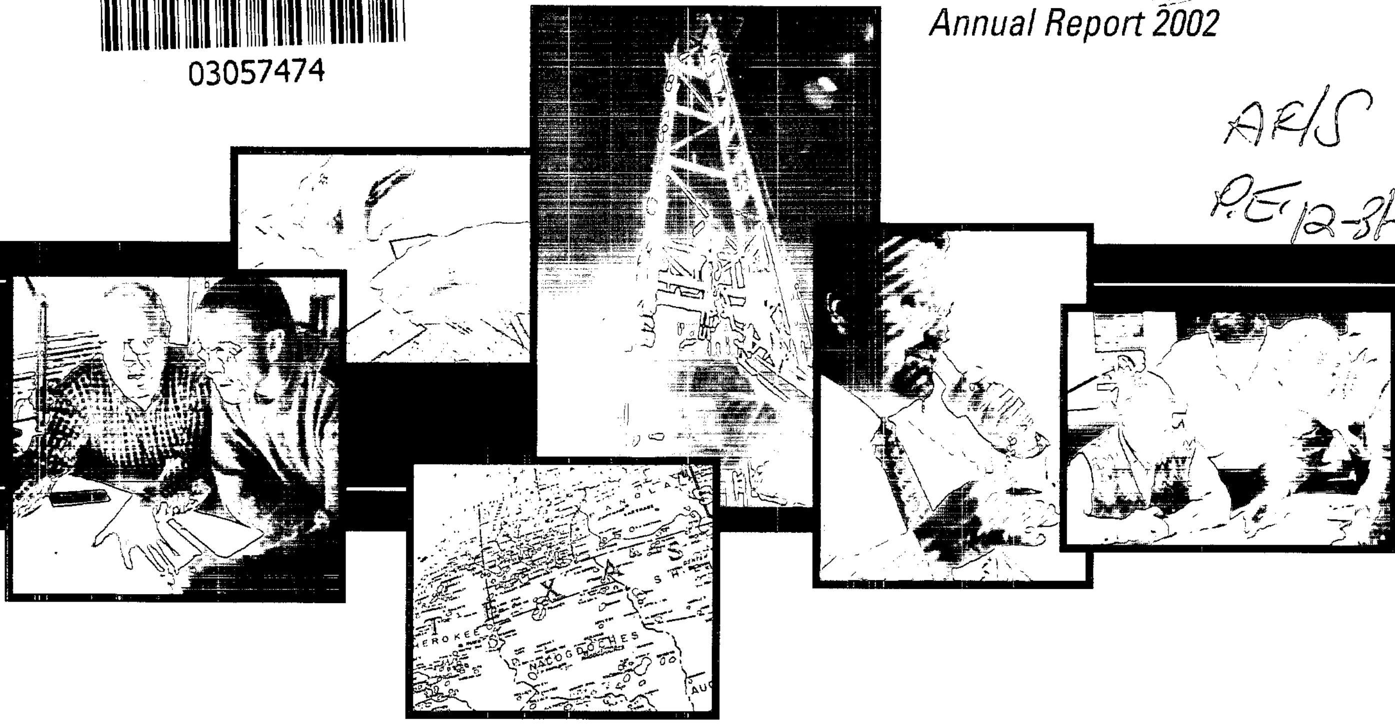


KCS

About the Company

KCS Energy, Inc. is an independent energy company engaged in the acquisition, exploration and production of natural gas and crude oil with operations focused in the Mid-Continent and Gulf Coast regions.

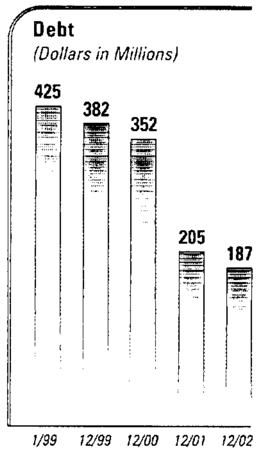
Highlights

During the past year, KCS...

- ✓ Paid off the remaining balance of the Senior note obligations
- ✓ Reduced debt for the fourth consecutive year
- ✓ Reduced operating expenses by 20% compared to 2001
- ✓ Drilled 53 wells with a 74% success ratio
- ✓ Significantly increased our drilling prospect inventory
- ✓ Secured a $90 million credit facility
- ✓ Exited 2002 in a stronger financial position, with increased financial flexibility

We closed the books on the year, having achieved our primary objective of meeting our Senior note obligations due January 15, 2003. In order to accomplish this, we sold certain non-core assets and curtailed our drilling and capital spending for the year, which permitted us to further reduce our debt.

As a result of these actions and in spite of a difficult period in the capital markets, we were successful in putting into place a $90 million credit facility in January 2003. At that time, we paid off the balance of the Senior notes and had more than $20 million available for future growth. Since then, we have repaid about $9 million of the amount initially borrowed under the facility.



In 2002, we reduced our debt by $18 million (the fourth consecutive year of debt reduction) and reduced our obligations under the production payment we sold in 2001 by 11.2 Bcfe, or over $45 million. In just 23 months we have already delivered 63% of the total obligation under that production payment. That leaves only 16.2 Bcfe left to deliver over 37 months, 6.8 Bcfe of which will be delivered in 2003. Importantly, that's 4.4 Bcfe less than in 2002. Assuming a $5.00 gas price, that would translate into more than $20 million additional cash flow for KCS from the same level of total volumes produced. We also continued our emphasis on cost control.

Our operating costs were reduced by 20% and our interest cost by 9%. As you can see, a lot has been accomplished in the last year.

On the operating front, we had very good drilling results in 2002. However, because of the sale of certain non-core properties and a reduction in our capital spending program, we ended the year with lower

oil and gas reserves. Nevertheless, with improved commodity prices, the present value of those reserves is approximately 70% higher than it was last year. We continued to position KCS for future growth and focused our efforts on developing additional prospects for upcoming exploitation. As a result, today we have an expanded portfolio of quality prospects to be drilled over the next several years.

Despite lower commodity prices for much of the year, we reported nearly \$10 million of income before income taxes in 2002. There were however, two unusual non-cash items which resulted in a reported loss for the year. First, in June we reflected a non-cash tax expense of \$15.9 million to increase the reserve for realization of deferred tax assets. Second, we changed our method of accounting for depreciation, depletion and amortization to the units of production method now used by most companies in our industry and recorded a charge of \$6.2 million to reflect the cumulative effect of that change.

As we move forward in 2003, the outlook for KCS is very bright. The combination of excellent commodity prices and a solid base of production from existing properties should provide excellent cash flow in 2003. This, coupled with the increased financial flexibility our new credit facility provides and the significant portfolio of high quality drilling prospects, should enable us to once again build our reserves and production. We are already aggressively drilling in several areas. We will also look

to further reduce our debt in 2003. In fact, as I mentioned earlier, we have already repaid $9 million of the initial $69 million borrowed under the new credit facility.

The sad chapter for us in 2002, was the passing of our Chairman and friend Stewart B. Kean. Stewart made immeasurable contributions to KCS since its inception in 1988. His guidance and leadership will be missed.

Our employees' dedication has enabled KCS to reduce debt by over $238 million in just four years, while maintaining a solid base of reserves and production and building a backlog of drilling prospects. They are now aggressively pursuing development of those prospects with renewed vitality and enthusiasm. I want to thank them for their efforts and loyalty, and thank you for your continued support.

James W. Christmas
President and Chief Executive Officer
March 31, 2003

What is the Operations Outlook for 2003?

Bill Hahne, Chief Operating Officer

During recent years, KCS has taken the necessary steps to restructure our operations, reduce our debt, and position the Company for future long-term

growth and increasing profitability. In the last four years we sold 97 Bcfe of reserves to reduce our debt by $238 million. Contributing significantly to our debt reduction was the production payment sold in 2001. We further streamlined our operations in 2002 with the sale of non-core properties. This, coupled with a reduced capital spending program, helped us to successfully retire the Company's Senior notes in January.

Thus, we entered 2003, a leaner company, with a stronger balance sheet and increased financial flexibility, poised for a new period of growth.

☆ Wells Drilled in 2002

In 2002, we drilled 53 wells with a 74% success rate. In 2003, we anticipate using our cash flow to accelerate the drilling of the significant inventory of prospects our technical staff has compiled. We expect to drill 60 to 80 wells with an initial budget of $50 million. Our goal is to increase both production and reserves in order to continue strengthening KCS.

This program will include drilling in existing fields such as Sawyer Canyon and Elm Grove. It will also present KCS with some new multi-well opportunities in North Louisiana, the Arkoma Basin, and South Texas. We believe this aggressive drilling program will add value and allow us to capitalize on the current commodity prices.

Commodity prices have increased dramatically in recent months. What is the focus of your efforts for 2003?

Harry Stout, Senior Vice President – Marketing and Risk Management

Present gas and oil price levels should permit KCS to grow and further reduce debt in 2003. I envision two key objectives for my group:

1. To benefit this year from price increases, while protecting the Company against price declines and;
2. To execute a program designed to capture the benefit of these prices for a portion of our production beyond 2003.

What is the proposed drilling program for the Mid-Continent Division?

Brad Magill, Vice President, Mid-Continent Exploration

The Mid-Continent Division's inventory of drilling projects is at a historical high and offers significant promise for KCS. In recent years, we have

narrowed our focus to three main areas: 1. The Sawyer Canyon Field; 2. North Louisiana and East Texas; and 3. The Arkoma Basin. In 2003, we will continue to build off of the drilling success we had in the Elm Grove Field in North Louisiana last year. We will also expand our drilling activity in new areas including the Talahina area in the Arkoma Basin where we made a significant discovery in 2002. Further, we have new Hosston and Travis Peak prospects in the North Louisiana and East Texas areas that should have multi-well potential.

What development is anticipated in the Sawyer Canyon Field in 2003?

Jeannette King, Mid-Continent Geologist

The 2003 drilling program is underway in Sawyer Canyon. Our initial phase includes the development of 17 locations. When this is completed, we will evaluate our success, the level of gas prices and available budget. Based upon our findings, we will move to the next phase of our program.

Elm Grove is one of KCS' most active fields. What's in store for 2003?

Kelly Byram, Mid-Continent Geologist

In 2002, we drilled six successful wells and performed two workovers, with our net field production doubling from 4 Mmcfepd to 8 Mmcfepd from this

activity. The pace will pick up in 2003 as we expect to drill between five and 10 wells, in addition to completing five to 10 workovers.

What is KCS' focus in the Gulf Coast region?

Cliff Foss, Senior Vice President – Gulf Coast Exploration

We continue to have our best results in the South Texas Wilcox, Frio, and Vicksburg trends. That's where we expect to see the most growth. In 2002, we had an outstanding discovery in the La Reforma Field in Hidalgo County. We plan to follow up on that well and continue our exploration in South Texas. We expect to pursue over 20 prospects this year.

Tell us about your recent La Reforma discovery.

Jim Travillo, Gulf Coast Exploration Manager

This well is a joint venture where we combined KCS' technical resources with our partner's contribution of acreage and seismic data. The result was

the discovery of over 600 feet of prolific Vicksburg pay. We are continuing our technical analysis, which could result in three to five additional drilling prospects in the area.

What is KCS' main strength?

Julie Smith, Vice President, Human Resources

It's the Company's employees! They contribute to KCS' future with their dedication, capabilities and loyalty. We have 119 employees (some of whom are featured in this year's annual report) in Houston, Tulsa, Shreveport and at numerous field office locations including West Texas, Michigan, Wyoming, California and Louisiana.

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

Form 10-K

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

For the fiscal year ended December 31, 2002

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 1-11698

KCS Energy, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**22-2889587**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

5555 San Felipe Road, Houston, Texas 77056
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code:
(713) 877-8006

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

Title of Class	Name of each exchange on which registered
Common Stock, par value $0.01 per share	New York Stock Exchange
8⅞ Senior Subordinated Notes due 2006	New York Stock Exchange

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

Title of Class

Common Stock, par value $0.01 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: ☑ No ☐

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

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

The aggregate market value of the 31,656,301 shares of the Common Stock held by non-affiliates of the registrant at the $1.75 closing price on June 28, 2002 (the last business day of the most recently completed second quarter) was $55,398,527.

Applicable Only to Registrants Involved in Bankruptcy Proceedings During the Preceding Five Years: Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes: ☐ No ☐

Not applicable. Although the registrant was involved in bankruptcy proceedings during the preceding five years, the registrant did not distribute securities under its plan of reorganization.

Number of shares of Common Stock outstanding as of the close of business on March 12, 2003: 38,008,028

DOCUMENTS INCORPORATED BY REFERENCE

Part III incorporates information by reference from the registrant's Proxy Statement for the 2003 Annual Meeting of Shareholders to the extent indicated herein.

KCS ENERGY, INC.

FORM 10-K
Report for the Year Ended December 31, 2002

PART I

Item 1. *Business*

General development of business

KCS Energy, Inc., a Delaware Corporation ("KCS" or the "Company"), is an independent oil and gas company engaged in the acquisition, exploration and production of natural gas and crude oil with operations predominately in the Mid-Continent and onshore Gulf Coast regions. The Company was formed in 1988 in connection with the spin-off of the non-utility businesses of NUI Corporation, a New Jersey-based natural gas distribution company that had been engaged in the oil and gas exploration and production business as well as numerous other businesses since the late 1960s.

The Company's main objective in 2002 was to position itself to meet its Senior Note obligations due January 15, 2003. In order to meet this objective, KCS curtailed its drilling and overall capital expenditure programs and sold certain non-core assets. These actions positioned the Company to reduce its debt and negotiate the financing necessary to pay off the remaining portion of the maturing Senior Notes during a difficult period in the capital markets. Although the asset sales and curtailed drilling and capital expenditure programs resulted in lower production and reserves in 2002, the Company exited the year in a stronger financial position, with increased financial flexibility, a focused asset base in its core areas, and a quality multi-year drilling prospect inventory.

On January 14, 2003, the Company completed the arrangements necessary to amend and restate its existing credit agreement with a group of institutional lenders. The amended facility provides $90.0 million of borrowing capacity, $40.0 million in the form of a term loan and $50.0 million in revolving facilities, and matures on October 3, 2005. Initial proceeds of $69.3 million were used primarily to pay off the balance of the maturing Senior Note obligations, leaving $20.7 million of available borrowing capacity under the facility.

The Company reduced lifting costs (lease operating expenses and production taxes) by 20% and general and administrative expenses by 7% in 2002 and expects further reductions in 2003. With the completion of the financing and the implementation of this cost reduction program, the Company believes it is positioned to capitalize on the strong natural gas price environment and to focus on developing its prospect inventory to grow reserves and production in its core areas.

Overall, KCS has reduced its debt from a peak of $425 million in early 1999 to $194.3 million on January 15, 2003 and is committed to further debt reduction.

Oil and Gas Operations

All of the Company's exploration and production activities are located within the United States. The Company competes with major oil and gas companies, other independent oil and gas concerns and individual producers and operators in reserve and leasehold acquisitions, and the exploration, development, production and marketing of oil and gas, as well as contracting for equipment and hiring of personnel. Oil and gas prices have been volatile historically and are expected to be volatile in the future. Prices for oil and gas are subject to wide fluctuation in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors that are beyond the Company's control. These factors include political conditions in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign imports, the level of consumer product demand, weather conditions, domestic and foreign government regulations and taxes, the price and availability of alternative fuels and overall economic conditions.

Exploration and Production Activities

During the three-year period ended December 31, 2002, the Company participated in drilling 255 gross (111.7 net) wells, of which 82% were successful. In 2002, the Company participated in drilling 53 gross (22.1 net) wells, of which 74% were successful. This included 34 (15.4 net) development wells and 19 (6.7 net) exploration wells with success rates of 85% and 53%, respectively.

In 2002, the Company concentrated its drilling programs predominately in the Mid-Continent and Gulf Coast regions. In the Mid-Continent region, the Company explores in Oklahoma (Anadarko and Arkoma basins), north Louisiana, west Texas and Michigan. During 2002, the Company drilled 29 gross (16.7 net) wells in this region with an 86% success ratio.

Thirteen of the wells drilled in 2002 were in the north Louisiana core area, including six wells in the Elm Grove Field, a discovery in the Stockman Creek Field, a step-out location in the South Drew Field and three development wells in the Simsboro Field. The Company has a multi-year inventory of locations in north Louisiana and anticipates a significant portion of its 2003 program to be focused on this area.

Eight wells were drilled in Oklahoma in 2002, including the Talihina Field discovery in Latimer County. The Company also had excellent results in extension drilling in the Panola Field.

KCS curtailed its drilling to an aggregate of only five wells in the Sawyer Canyon Field in west Texas and the West Shugart Field in New Mexico in order to conserve cash. A substantial increase in drilling is expected in the Sawyer Canyon Field in 2003.

In the Gulf Coast region, the Company explores in south Texas and the Mississippi salt basin. During 2002, the Company drilled 24 gross (5.4 net) wells with a 58% success ratio in this region.

In south Texas, the Company participated in 17 wells, including discoveries in the Dolan and La Reforma fields. The Guerra C-1 in the La Reforma Field appears to be the most significant discovery of the year with follow-up drilling anticipated in 2003.

The Company also made four small acquisitions of reserves, all with future drilling potential.

A larger inventory of drilling prospects and higher levels of expected internally generated cash flow should result in increased drilling and workover activity in 2003.

Volumetric Production Payment Program

From August 1994 through December 31, 2002, the Company augmented its working interest ownership of properties with a VPP program, a method of acquiring oil and gas reserves scheduled to be delivered in the future at a discount to the then current market price in exchange for an up-front cash payment. A VPP acquisition entitles the Company to a priority right to a specified volume of oil and gas reserves scheduled to be produced and delivered on an agreed delivery schedule. Typically, the estimated proved reserves of the properties underlying a VPP are substantially greater than the specified reserve volumes required to be delivered pursuant to the production payment. Although specific terms of its VPPs varied, the Company was generally entitled to receive delivery of its scheduled oil and gas volumes at agreed delivery points, free of drilling and lease operating costs and free of state severance taxes. The Company believes that its VPP program diversified its reserve base while achieving attractive rates of return and minimizing exposure to certain development, operating and reserve volume risks.

From the inception of the VPP program in August 1994, the Company invested $213.6 million under the VPP program and acquired proved reserves of 120.3 Bcfe of natural gas and oil. Through December 31, 2002, the Company realized approximately $293.9 million from the sale of oil and gas acquired under the program and 10.6 Bcfe of a VPP which was converted to a working interest after its acquisition. Due to limited capital availability, the Company made only minimal VPP investments after 1999, and did not make any VPP investments in 2001 or 2002. As a result, final deliveries under the Company's VPP acquisition program were received in December 2002. The Company is considering the use of joint venture partnerships or similar arrangements with third parties to fund another VPP acquisition program in the future.

Production Payment

In connection with its emergence from bankruptcy in 2001, the Company sold a 43.1 Bcfe (38.3 Bcf of gas and 797,000 barrels of oil) production payment to be delivered in accordance with an agreed schedule over a five-year period for net proceeds of approximately $175 million (the "Production Payment"). See Notes 1 and 2 to Consolidated Financial Statements. Amortization of deferred revenue attributable to volumes delivered under the Production Payment comprised 38% and 36% of the Company's oil and gas revenue in 2002 and 2001, respectively. Other than this amortization of deferred revenue, no customer accounted for more than 10% of the Company's revenues in 2002, 2001 or 2000.

Raw Materials

The Company obtains its raw materials from various sources, which are presently considered adequate. While the Company regards the various sources as important, it does not consider any one source to be essential to its business as a whole.

Patents and Licenses

There are no patents, trademarks, licenses, franchises or concessions held by the Company, the expiration of which would have a material adverse effect on its business.

Seasonality

Demand for natural gas and oil is seasonal, principally related to weather conditions and access to pipeline transportation.

Oil and Gas Risk Factors

As described below, the Company's oil and gas operations make it subject to a variety of risks.

Volatile Nature of Oil and Gas Markets; Fluctuation in Prices. The Company's future financial condition and operating results are highly dependent on the demand for and prices received for the Company's oil and gas production and on the costs of acquiring, exploring for, developing and producing reserves. Oil and gas prices have been, and are expected to continue to be, volatile. Prices for oil and gas fluctuate widely in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty, and a variety of additional factors beyond the Company's control. These factors include:

- worldwide political conditions (especially in the Middle East and other oil-producing regions);
- the domestic and foreign supply of oil and gas;
- the level of consumer demand;
- weather conditions;
- domestic and foreign government regulations and taxes; and
- the price and availability of alternative fuels and overall economic conditions.

A decline in oil or gas prices may adversely affect the Company's cash flow, liquidity and profitability. Lower oil or gas prices also may reduce the quantity of the Company's oil and gas that can be produced economically. It is impossible to predict future oil and gas price movements with any certainty. Under the full cost method of accounting, capitalized costs of oil and gas properties, net of accumulated depreciation, depletion and amortization ("DD&A") and related deferred taxes, are limited to the sum of the present value of estimated future net revenues from proved oil and gas reserves at current prices discounted at 10%, net of related tax effects plus the lower of cost or fair value of unproved properties. To the extent that the capitalized costs exceed this "ceiling" limitation at the end of any quarter, such excess is expensed. Given the volatility of oil and gas prices, it is possible that the Company's estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline significantly, even if only for a short period of time, it is possible that non-cash writedowns of oil and gas properties could occur.

Dependence on Acquiring and Finding Additional Reserves. The Company's prospects for future growth and profitability depend primarily on its ability to replace oil and gas reserves through acquisitions, development and exploratory drilling. Acquisitions may not be available at attractive prices. The decision to purchase, explore or develop a property depends in part on geophysical and geological analyses and engineering studies, which are often inconclusive or subject to varying interpretations. Consequently, there can be no assurance that the Company's acquisition, development and exploration activities will result in significant additional reserves, nor can there be any assurance that the Company will be successful in drilling economically productive wells. Without acquisition, development or discovery of additional reserves, the Company's proved reserves and revenues will decline.

Reliance on Estimates of Reserves and Future Net Cash Flows. This Form 10-K includes estimates by independent petroleum engineers of the Company's oil and gas reserves and future net cash flows. There are numerous uncertainties inherent in estimating quantities of oil and gas reserves, including many factors beyond the Company's control. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. To estimate oil and gas reserves and future net cash flow, reserve engineers make a number of assumptions, which may vary considerably from actual results. These assumptions include:

- the effects of regulation by government agencies;
- future oil and gas prices;
- operating costs;
- severance and excise taxes; and
- development costs.

For these reasons, reserve estimates, classifications of reserves based on risk of recovery, and estimates of future net cash flows prepared by different engineers, or by the same engineers at different times, may vary significantly. Actual production, revenues and expenditures with respect to the Company's reserves likely will vary from estimates, possibly materially. The Company's projected reserves and future cash flows may be subject to revisions based upon production history, oil and gas prices, performance of counterparties under the Company's contracts, operating and development costs and other factors.

This Form 10-K refers to the present value of future net revenues ("PV-10 value") of the Company's reserves. The PV-10 value of reserves means the present value of estimated future net revenues, computed by applying year-end prices to estimated future production from the reserves, deducting estimated future expenditures, and applying a discount factor of ten percent (10%). The PV-10 values referred to in this Form 10-K should not be construed as the current market value of the Company's estimated oil and gas reserves. In accordance with applicable requirements of the Securities and Exchange Commission ("SEC"), PV-10 value is generally based on prices and costs as of the date of the estimate, whereas actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as (i) the amount and timing of actual production and expenditures to develop and produce reserves, (ii) the supply and demand for oil and gas, and (iii) changes in government regulations or taxation. In addition, the 10% discount factor, which the SEC requires to be used to calculate present value for reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company and its properties or the oil and gas industry in general.

Exploration Risks. Exploratory drilling activities are subject to many risks, and there can be no assurance that new wells drilled by the Company will be productive or that the Company will recover all or any portion of its investment. Drilling for oil and gas may be unprofitable due to a number of risks, including:

- wells may not be productive, either because commercially productive reservoirs were not encountered or for other reasons;

- wells that are productive may not provide sufficient net revenues to return a profit after drilling, operating and other costs; and

- the costs of drilling, completing and operating wells are often uncertain.

In addition, the Company's drilling operations may be curtailed, delayed or canceled as a result of numerous factors, many of which are beyond the Company's control. These factors may include title problems, weather conditions, compliance with government requirements, pressure or irregularities in formations, equipment failures or accidents, and shortages or delays in the delivery of equipment and services.

Marketing Risks. The Company's ability to market oil and gas at commercially acceptable prices depends on, among other factors, the availability and capacity of gathering systems and pipelines, federal and state regulation of production and transportation, general economic conditions and changes in supply and demand. The Company's inability to respond appropriately to changes in these factors could negatively effect the Company's profitability.

Acquisition Risks. Acquisitions of oil and gas businesses and properties have been an important element of the Company's business, and the Company will continue to pursue acquisitions in the future. Even though the Company performs a review (including review of title and other records) of the major properties it seeks to acquire that it believes is consistent with industry practices, such reviews are inherently incomplete. It is generally not feasible for the Company to review in-depth every property and all records involved in each acquisition. Even an in-depth review may not reveal existing or potential problems or permit the Company to become familiar enough with the properties to assess fully their deficiencies and potential. The success of any acquisition will depend on a number of factors, including the ability to estimate accurately the recoverable volumes of reserves, rates of future production and future net revenues attainable from the reserves and to assess possible environmental liabilities. Even when problems are identified, the Company may assume certain environmental and other risks and liabilities in connection with acquired businesses and properties.

Operating Risks. The Company's operations are subject to numerous operating risks inherent in the oil and gas industry which could result in substantial losses to the Company. These risks include, for example, fires, explosions, well blow-outs, pipe failure, oil spills, natural gas leaks or ruptures, or other discharges of toxic gases or other pollutants. The occurrence of these risks could result in substantial losses to the Company due to personal injury, loss of life, damage to or destruction of wells, production facilities or other property or equipment, or damage to the environment. Such occurrences could also subject the Company to clean-up obligations, regulatory investigation, penalties or suspension of operations. Further, the Company's operations may be materially curtailed, delayed or canceled as a result of numerous factors, including the presence of unanticipated pressure or irregularities in formations, accidents, title problems, weather conditions, compliance with government requirements and shortages or delays in obtaining drilling rigs or in the delivery of equipment. In accordance with customary industry practice, the Company maintains insurance against some, but not all, of the risks described above. There can be no assurance that the levels of insurance maintained by the Company will be adequate to cover any losses or liabilities. The Company cannot predict the continued availability of insurance or availability at commercially acceptable premium levels.

Competitive Industry. The oil and gas industry is highly competitive. The Company competes with major oil and gas companies, other independent oil and gas concerns and individual producers and operators to acquire oil and gas businesses, properties and equipment, and to hire personnel necessary to explore for, develop, produce, transport and market oil and gas. Many of these competitors have financial and other resources that substantially exceed those available to the Company.

Government Regulation. The Company's business is subject to numerous federal, state and local laws and regulations, including energy, environmental, conservation, tax and other laws and regulations relating to the energy industry. Administrative and legislative proposals are frequently introduced, at both the state and federal level which, if adopted or enacted, might significantly affect the industry. The Company cannot predict whether, or when, such laws and regulations may be enacted or adopted, and cannot predict the cost of compliance with such changing laws and regulations or their effects on oil and gas use or prices.

Regulation

General. The Company's business is affected by numerous laws and regulations, including energy, environmental, conservation, tax and other laws and regulations relating to the energy industry. Changes in any of these laws and regulations could have a material adverse effect on the Company's business. In view of the many uncertainties with respect to current and future laws and regulations, including their applicability to the Company, the Company cannot predict the overall effect of such laws and regulations on its future operations.

The Company believes that its operations comply in all material respects with all applicable laws and regulations. Although such laws and regulations have a substantial impact upon the energy industry, generally these laws and regulations do not appear to affect the Company any differently, or to any greater or lesser extent, than other similar companies in the energy industry.

The following discussion describes certain laws and regulations applicable to the energy industry and is qualified in its entirety by the foregoing.

State Regulations Affecting Production Operations. The Company's onshore exploration, production and exploitation activities are subject to regulation at the state level. Laws and regulations vary from state to state, but generally include laws to regulate drilling and production activities and to promote resource conservation. Examples of such state laws and regulations include laws which:

- require permits and bonds to drill and operate wells;
- regulate the method of drilling and casing wells;
- establish surface use and restoration requirements for properties upon which wells are drilled;
- regulate plugging and abandonment of wells;
- regulate the disposal of fluids used or produced in connection with operations;
- regulate the location of wells, including establishing the minimum size of drilling units and the minimum spacing between wells;
- concern unitization or pooling of oil and gas properties;
- establish maximum rates of production from oil and gas wells; and
- restrict the venting or flaring of gas.

These regulations and requirements may affect the profitability of affected properties or operations. The Company is unable to predict the future cost or impact of complying with such regulations.

Regulations Affecting Sales and Transportation of Oil and Gas. Various aspects of the Company's oil and gas operations are regulated by agencies of the federal government. Pursuant to the Natural Gas Act of 1938 (the "NGA") and the Natural Gas Policy Act of 1978 (the "NGPA"), the Federal Energy Regulatory Commission (the "FERC") regulates the transportation of natural gas in interstate commerce including some natural gas produced or marketed by the Company. In the past, the federal government regulated the prices at which the Company's natural gas could be sold. Currently, "first sales" of natural gas by producers and marketers, and all sales of crude oil, condensate and natural gas liquids can be made at uncontrolled market prices, but Congress could reenact price controls at any time. The FERC continues to examine its policies affecting the natural gas industry. It is not possible for the Company to predict what effect, if any, the ultimate outcome of the FERC's various initiatives will have on the Company's operations.

The FERC continues to authorize the sale and abandonment from NGA regulation of natural gas gathering facilities previously owned by interstate pipelines. Such facilities and services on such systems may be subject to regulation by state authorities in accordance with state law. In general, state regulation of gathering facilities includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, but does not generally entail regulation of the gathering rates charged. Natural gas gathering may receive greater regulatory scrutiny by state agencies in the future, and in that event, the Company's gathering operations could be adversely affected; however, the Company does not believe that it would be affected by such regulation any differently from other natural gas producers or gatherers. The effects, if any, of changes in existing state or FERC policies on the Company's gas gathering or gas marketing operations are uncertain.

Sales of crude oil, condensate and natural gas liquids by the Company are not currently regulated and are made at market prices. The price the Company receives from the sale of these products is affected by the cost of transporting the products to market. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system for transportation rates for oil pipelines, which generally index such rates to inflation, subject to certain conditions and limitations. The Company is not able to predict with certainty what effect, if any, these regulations will have on its business, but other factors being equal, the regulations may tend to increase transportation costs or reduce wellhead prices under certain conditions.

Federal Regulations Affecting Production Operations. The Company also operates federal and Indian oil and gas leases, which are subject to the regulation of the United States Bureau of Land Management ("BLM"), the Bureau of Indian Affairs ("BIA") and the United States Minerals Management Service ("MMS").

MMS, BIA and BLM leases contain relatively standardized terms requiring compliance with detailed regulations and orders. Such regulations specify, for example, lease operating, safety and conservation standards, well plugging and abandonment requirements, and surface restoration requirements. In addition, the BIA, BLM and MMS generally require lessees to post bonds or other acceptable surety to assure that their obligations will be met. The cost of such bonds or other surety can be substantial and there is no assurance that any particular lease operator can obtain bonds or other surety in all cases. Under certain circumstances, the MMS, BIA or BLM may require operations on federal or Indian leases to be suspended or terminated. Any such suspension or termination could adversely affect the Company's interests.

Effective June 1, 2000, the MMS amended its regulations governing the calculation of royalties and the valuation of crude oil produced from federal leases. The amendments modify the valuation procedures for both arm's length and non-arm's length crude oil transactions to decrease reliance on posted oil prices and assign a value to crude oil that better reflects its market value. Similar changes have been proposed with regard to valuation of Indian royalty oil. The Company is not able to predict with certainty the effect, if any, these regulations will have on its business, but believes that the regulations will not have a greater effect on the Company than on other similar companies in the energy industry.

The MMS also continues to consider changes to the way it values natural gas for royalty payments. These changes would establish an alternative market-based method to calculate royalties on certain natural gas sold to affiliates or pursuant to non-arm's length sales contracts. Discussions among the MMS, industry officials and Congress are continuing, although it is uncertain whether and what changes may ultimately be proposed regarding natural gas royalty valuation.

Additional proposals and proceedings that might affect the oil and gas industry are pending before Congress, the FERC, the MMS, the BLM, the BIA, state commissions and the courts. The Company cannot predict when or whether any such proposals may become effective. Historically, the natural gas industry has been very heavily regulated. There is no assurance that the current regulatory approach pursued by various agencies will continue indefinitely. Notwithstanding the foregoing, it is not anticipated that compliance with existing federal, state and local laws, rules and regulations will have a material or significantly adverse effect upon the capital expenditures, earnings or competitive position of the Company.

Operating Hazards and Environmental Matters. The oil and gas business involves a variety of operating risks, including the risk of fires, explosions, well blow-outs, pipe failure, oil spills, natural gas leaks or ruptures, or other discharges of toxic gases or other pollutants. The occurrence of these risks could result in substantial losses to the Company due to personal injury, loss of life, damage to or destruction of wells, production facilities or other property or equipment, or damage to the environment. Such occurrences could also subject the Company to clean-up obligations, regulatory investigation, penalties or suspension of operations. Although the Company believes it is adequately insured, such hazards may hinder or delay drilling, development and production operations.

Oil and gas operations are subject to extensive federal, state and local laws and regulations that regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. These laws and regulations may:

- require the acquisition of a permit before drilling commences;
- restrict the types, quantities and concentration of substances that can be released into the environment;
- restrict drilling activities on certain lands, such as wetlands or other protected areas; and
- impose substantial liabilities for pollution resulting from drilling and production operations.

Failure to comply with these laws and regulations may also result in civil and criminal fines and penalties.

The Company's properties, and any wastes spilled or disposed of by the Company, may be subject to federal or state environmental laws that could require the Company to remove the wastes or remediate contamination. For example, the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the original conduct, on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to assert claims for personal injury and property damage allegedly caused by the release of hazardous substances. See "Environmental Claims" below.

Also, the Company's operations may be subject to the Clean Air Act ("CAA") and comparable state and local requirements. The Company may be required to incur certain capital expenditures for air pollution control equipment in connection with maintaining or obtaining permits and approvals relating to air emissions. The Company does not believe that its operations will be materially adversely affected by any such requirements.

In addition, the U.S. Oil Pollution Act ("OPA") requires owners and operators of facilities in or near rivers, creeks, wetlands, coastal waters, offshore waters, and other U.S. waters to adopt and implement plans and procedures to prevent oil spills. OPA also requires affected facility owners and operators to demonstrate that they have at least $35 million in financial resources to pay for the costs of cleaning up an oil spill and compensating any parties damaged by an oil spill. Such financial assurances may be increased to as much as $150 million if a formal assessment indicates such an increase is warranted.

The Company's operations are also subject to the federal Clean Water Act ("CWA") and analogous state laws. Among other matters, such laws may prohibit the discharge of waters produced in association with hydrocarbons into coastal waters. To comply with this prohibition, the Company may be required to incur capital expenditures or increased operating expenses. The CWA also regulates discharges of storm water runoff. This program requires covered facilities to obtain individual permits, participate in a group permit or seek coverage under a general permit. While certain of its properties may require permits for discharges of storm water runoff, the Company believes that it will be able to obtain, or be included under, such permits, where necessary. Such coverage may require the Company to make minor modifications to existing facilities and operations that would not have a material effect on the Company.

Pursuant to the Safe Drinking Water Act, underground injection control ("UIC") wells, including wells used in enhanced recovery and disposal operations associated with oil and gas exploration and production activities, are subject to regulation. Such regulations include permitting, bonding, operating, maintenance and reporting requirements.

In addition, the disposal of wastes containing naturally occurring radioactive material, which is commonly encountered during oil and gas production, is regulated under state law. Typically, wastes containing naturally occurring radioactive material can be managed on-site or disposed of at facilities licensed to receive such waste at costs that are not expected to be material.

Environmental Claims. The Company owns the following two oil and gas leases covering an aggregate of approximately 11,000 acres in Los Angeles County, California: a) Oil and Gas Lease dated June 13, 1935, from Newhall Land and Farming Company, as Lessor, to Barnsdall Oil Company, as Lessee (the "RSF Lease"); and b) Oil and Gas Lease dated June 6, 1941, from the Newhall Corporation, as Lessor, to C.G. Willis, as Lessee (the "Ferguson Lease"). The RSF Lease and the Ferguson Lease are herein called the "Leases." Oil and gas production from such lands commenced shortly after the RSF Lease was granted and has continued to date.

From the inception of the Leases until October 30, 1990, the Leases were owned by entities that through corporate succession and name change ultimately became Sun Operating Limited Partnership ("Sun L.P."). On October 30, 1990, Sun L.P. transferred the Leases to DKM Offshore Energy, Inc. ("DKM") and Neste Oil Services Inc. ("Neste"). In the assignment of the Leases, Sun L.P. indemnified DKM and Neste from environmental claims resulting from the indemnitors' operations provided that such environmental claims were made within ten years from October 30, 1990. Shortly after the transfer to DKM and Neste, DKM acquired Neste's rights and, subsequently, DKM became Medallion California Properties Company ("Medallion California"). Later, the Company acquired the stock of Medallion California. Also, Sun L.P. became Kerr-McGee Oil & Gas Onshore L.P. ("Kerr-McGee L.P."). In connection with the purchase of Medallion California by KCS, InterCoast Energy Company ("InterCoast"), the seller, indemnified the Company and Medallion California for up to 90% of the costs of environmental remediation not assumed by Kerr-McGee L.P. InterCoast's parent, MidAmerican Capital Company ("MidAmerican"), guaranteed InterCoast's indemnity obligations. The nature and extent of both the Sun L.P. and InterCoast indemnities were recently classified by an Agreed Judgment entered in a Harris County Texas District Court. See Note 10 to the Consolidated Financial Statements included herein.

Kerr-McGee L.P. identified 21 sites for cleanup on the lands covered by the Leases and had a Remedial Action Plan ("RAP") approved by the Los Angeles County Regional Water Quality Control Board to effect such cleanup. The primary contaminant identified for this cleanup is petroleum waste. The Company has been advised that Kerr-McGee L.P. has substantially completed the cleanup of 19 of these sites. The Company believes that Kerr-McGee L.P. will ultimately accomplish the RAP and that the Company has no exposure for remediation of these 21 sites.

In addition to the 21 sites identified in the RAP, the Company has identified and analyzed samples from numerous additional sites and has found that certain of those sites are contaminated with petroleum waste. The Company has described those sites to the lessors, Kerr-McGee L.P., InterCoast and MidAmerican. The Company believes Kerr-McGee L.P. will ultimately be responsible for remediation of substantially all of the additional sites.

Litigation is currently pending in which the Lessor of the RSF Lease seeks, among other remedies, damages for alleged environmental contamination and site restoration of the lands covered by the RSF Lease, and in which Medallion California claims indemnification is owed by Kerr-McGee L.P., InterCoast and MidAmerican. See Note 10 to the Consolidated Financial Statements included herein.

Employees

The Company has reduced its workforce over the last several years and employed a total of 119 persons on December 31, 2002.

Available Information

The Company's Internet website is *www.kcsenergy.com.* The Investor Relations portion of the Company's website is *www.kcsenergy.com/html/investor.html* and it contains information about the Company, including its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These reports may be downloaded, free of charge, from the website. Since November 15, 2002, the Company has generally made these reports available on its website within a few days after they are electronically filed with, or furnished to, the SEC. In the future, the Company intends to make these reports available as soon as reasonably practicable after they are electronically filed with, or furnished to, the Securities and Exchange Commission. Paper copies of these reports are available free of charge upon request.

Item 2. *Properties*

Oil and Gas Properties

The following table sets forth data as of December 31, 2002 regarding the number of gross and net producing wells, and the estimated quantities of proved oil and gas reserves attributable to the Company's principal operating regions.

	Producing Wells				Estimated Proved Reserves		
	Gas		Oil				
	Gross	Net	Gross	Net	Gas (Mmcf)	Oil (Mbbls)	Total (Mmcfe)
Mid-Continent Region	645	471.8	292	96.3	101,943	5,006	131,979
Gulf Coast Region	191	83.0	43	19.0	53,050	1,766	63,646
Total Company	836	554.8	335	115.3	154,993	6,772	195,625

Approximately 79% of the Company's reserves are attributable to wells it operates.

Mid-Continent Region

In the Mid-Continent region, the Company is pursuing opportunities primarily in Oklahoma (Anadarko and Arkoma basins), north Louisiana, west Texas and Michigan. This region also includes producing properties in the Rocky Mountains and California. The Company views the Mid-Continent region as providing a solid base for production replacement and plans to continue to exploit areas within the various basins that require additional wells for adequate reserve drainage and to drill low-risk exploration wells. These wells are generally step-out and extension type wells with moderate reserve potential.

Estimated proved reserves in the Mid-Continent region were 132.0 Bcfe as of December 31, 2002, representing approximately 67% of the Company's reserves. At December 31, 2002, the Company owned leasehold interests within the Mid-Continent region covering approximately 220,269 gross (168,010 net) acres.

Gulf Coast Region

The Gulf Coast region is primarily comprised of producing properties in south Texas, coastal Louisiana and the Mississippi Salt Basin and minor non-operated offshore properties. The Company conducts development programs and pursues moderate-risk, higher potential exploration drilling programs in this region. The Gulf Coast region has prospects which are expected to provide the key area of future growth for the Company. Estimated proved reserves in the region were 63.6 Bcfe as of December 31, 2002, which represented approximately 33% of the Company's reserves. The Company owns or controls approximately 209,311 gross (46,128 net) acres in the Gulf Coast region.

Oil and Gas Reserves

The reserve estimates and associated cash flows for all properties for the years ended December 31, 2002 and 2000 were prepared by Netherland, Sewell & Associates, Inc. ("NSA"). For the year ended December 31, 2001, the reserve estimates were prepared by the Company and audited by NSA.

The following table sets forth, as of December 31, 2002, summary information with respect to estimates of the Company's proved oil and gas reserves based on year-end prices. Oil and gas prices at December 31, 2002 are not necessarily reflective of the prices that the Company expects to receive in the future. For this reason and as a result of the uncertainties described in the following paragraph, the present value of future net revenues in the table should not be construed to be the current market value of the estimated oil and gas reserves owned by the Company.

	December 31, 2002
Proved reserves:	
Natural gas (Mmcf)	154,993
Oil (Mbbls)	6,772
Total (Mmcfe)	195,625
Future net revenues ($000)	$570,496
Present value of future net revenues ($000)	$343,522
Proved developed reserves:	
Natural gas (Mmcf)	124,451
Oil (Mbbls)	5,653
Total (Mmcfe)	158,369
Future net revenues ($000)	$465,956
Present value of future net revenues ($000)	$284,704

There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and in projecting future rates of production and future amounts and timing of development expenditures, including 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 and of engineering and geological interpretation and judgment. Estimates of proved undeveloped reserves are inherently less certain than estimates of proved developed reserves. The quantities of oil and gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures, geologic success and future oil and gas sales prices all may differ from those assumed in these estimates. In addition, the Company's reserves may be subject to downward or upward revision based upon production history, results of future development, prevailing oil and gas prices and other factors.

In accordance with SEC guidelines, the estimates of future net revenues from the Company's proved reserves and the present values thereof are made using oil and gas sales prices in effect as of the dates of such estimates and are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including, in the case of natural gas contracts, the use of fixed and determinable contractual price escalations. Gas prices are based on either a contract price or a December 31, 2002 spot price of $4.74 per MMbtu, adjusted by lease for Btu content, transportation fees and regional price differentials. Oil prices are based on a December 31, 2002 West Texas Intermediate posted price of $28.00 per barrel, adjusted by lease for gravity, transportation fees and regional price differentials. The prices for natural gas and oil are subject to substantial seasonal fluctuations, and prices for each are subject to substantial fluctuations as a result of numerous other factors. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Oil and Gas Risk Factors."

Acreage

The following table sets forth certain information with respect to the Company's developed and undeveloped leased acreage as of December 31, 2002. The leases in which the Company has an interest are for varying primary terms, and many require the payment of delay rentals to continue the primary term. The operator may surrender the leases at any time by notices to the lessors, by the cessation of production, fulfillment of commitments, or by failure to make timely payments of delay rentals.

State	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Texas	84,540	45,414	61,261	22,946
Louisiana	25,314	14,286	14,776	5,378
Michigan	7,027	3,221	163	114
New Mexico	1,829	1,387	640	232
Oklahoma	33,227	16,124	5,784	4,471
Wyoming	42,340	39,384	46,319	46,319
Offshore	84,913	7,695	—	—
Mississippi	2,400	500	14,797	2,897
Other	4,250	3,770	—	—
Total	285,840	131,781	143,740	82,357

Title to Interests

The Company believes that title to the various interests set forth above is satisfactory and consistent with the standards generally accepted in the oil and gas industry, subject only to immaterial exceptions which do not detract substantially from the value of the interests or materially interfere with their use in the Company's operations. The interests owned by KCS may be subject to one or more royalty, overriding royalty and other outstanding interests customary in the industry. The interests may additionally be subject to obligations or duties under applicable laws, ordinances, rules, regulations and orders of arbitral or governmental authorities. In addition, the interests may be subject to burdens such as production payments, net profits interests, development obligations under oil and gas leases and other encumbrances, easements and restrictions.

Drilling Activities

All of the Company's drilling activities are conducted through arrangements with independent contractors. Certain information with regard to the Company's drilling activities during the years ended December 31, 2002, 2001 and 2000, is set forth below.

Type of Well	Year Ended December 31,					
	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	1	0.8	2	0.5	8	4.7
Natural gas	28	13.4	63	29.0	58	33.2
Non-productive	5	1.2	6	3.4	8	2.3
Total	34	15.4	71	32.9	74	40.2
Exploratory:						
Oil	—	—	4	0.9	4	1.4
Natural gas	10	4.5	23	7.0	9	1.9
Non-productive	9	2.2	8	1.8	9	3.5
Total	19	6.7	35	9.7	22	6.8

At December 31, 2002, the Company was participating in the drilling of 1 gross (1.0 net) well.

Production

The following table presents certain information with respect to oil and gas production attributable to the Company's properties and average sales prices during the three years ended December 31, 2002, 2001 and 2000.

	Year Ended December 31,		
	2002	2001	2000
Production:(a)			
Gas (Mmcf)	29,672	36,873	41,089
Oil (Mbbl)	1,003	1,230	1,306
Liquids (Mbbl)	288	373	264
Summary (Mmcfe)			
Working interest	34,959	41,966	38,642
VPP	2,458	4,525	11,866
Total	37,417	46,491	50,508
Average Price:(b)			
Gas (per Mcf)	$ 3.25	$ 3.90	$ 3.69
Oil (per bbl)	20.52	20.67	27.35
Liquids (per bbl)	10.05	13.74	13.31
Total (per Mcfe)	$ 3.21	$ 3.75	$ 3.77
Production Cost per Mcfe	$ 0.82	$ 0.83	$ 0.68

(a) Production includes 11,196 Mmcfe and 15,716 Mmcfe in 2002 and 2001, respectively, dedicated to the Production Payment sold in February 2001. See Notes 1 and 2 to Consolidated Financial Statements.

(b) Includes the effects of hedging and, in 2002 and 2001, amortization of deferred revenue attributed to deliveries under the Production Payment sold in February 2001.

Other Facilities

Principal offices of the Company and its operating subsidiaries are leased in modern office buildings in Houston, Texas and Tulsa, Oklahoma.

The Company believes that all of its property, plant and equipment are well maintained, in good operating condition and suitable for the purposes for which they are used.

Item 3. *Legal Proceedings*

Additional information regarding the litigation described above under "Regulation — Environmental Claims" and information with respect to other legal proceedings is contained in Note 10 to the Consolidated Financial Statements.

Item 4. *Submission of Matters to a Vote of Security Holders*

No matter was submitted to a vote of security holders through the solicitation of proxies or otherwise during the three months ended December 31, 2002.

PART II

Item 5. *Market for the Registrant's Common Equity and Related Stockholder Matters*

The Company's common stock is traded on the New York Stock Exchange under the symbol KCS. On March 12, 2003, there were approximately 1,116 stockholders of record of the Company's common stock. This number does not include any beneficial owners for whom shares of common stock may be held in "nominee" or "street" name. The high and low sales prices for the common stock, as reported in the consolidated transactions reporting system, for each quarterly period during 2002 and 2001 are shown in the following table.

	2002			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Market Price				
High	$3.32	$4.01	$2.70	$2.25
Low	1.63	1.75	1.14	1.15

	2001			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Market Price				
High	$6.50	$10.20	$6.74	$4.00
Low	4.19	5.24	2.91	2.53

On March 12, 2003, the last reported sale price of the common stock on the New York Stock Exchange was $2.62 per share.

Dividend Policy

No cash dividends on the Company's common stock were paid in 2002 or 2001. KCS intends to retain earnings for use in the operation and expansion of its business, and therefore does not anticipate declaring a cash dividend on its common stock in the foreseeable future. KCS is currently restricted under its credit facilities from paying cash dividends on the common stock to stockholders. Any future determination to pay dividends on the common stock will be at the discretion of the board of directors and will be dependent upon then existing conditions, including the Company's financial condition, results of operations, contractual restrictions, capital requirements, business prospects, and such other factors as the board of directors deems relevant.

Equity Compensation Plan Information

The following table sets forth information as of December 31, 2002 with respect to compensation plans under which equity securities of the Company are authorized for issuance.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (A)#	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (B)$	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (A) (C)#
Equity Compensation Plans Approved by Stockholders ...	0	N/A	0
Equity Compensation Plans Not Approved by Stockholders:			
2001 Stock Plan	1,564,761(1)	4.73	1,989,092
Other	0	N/A	1,585,315(2)
Total	1,564,761	4.73	3,574,407

(1) Represents options granted under the KCS Energy, Inc. 2001 Employees and Directors Stock Plan. In addition, as of December 31, 2002, grants of 579,528 restricted shares were outstanding.

(2) Includes 775,989 shares authorized for issuance pursuant to the Company's employee stock purchase program and 809,326 shares authorized for issuance in connection with the Company's savings and investment (401(k)) plan.

Information regarding equity compensation plans that have not been approved by stockholders

KCS Energy, Inc. 2001 Employees and Directors Stock Plan ("2001 Stock Plan"). The 2001 Stock Plan was adopted as part of the Company's plan of reorganization (the "Plan") under Chapter 11 of Title 11 of the United States Bankruptcy Code. The Plan was approved by the Company's stockholders and creditors; however, the stockholders did not consider and vote on the 2001 Stock Plan independently of their consideration of the Plan. See Notes 2 and 4 to Consolidated Financial Statements. The 2001 Stock Plan provides that stock options, stock appreciation rights, restricted stock and bonus stock may be granted to employees of KCS. The 2001 Stock Plan provides that each non-employee director be granted stock options for 1,000 shares annually. The 2001 Stock Plan also provides that in lieu of cash, each non-employee director be issued KCS common stock with a fair market value equal to 50% of their annual retainer. The 2001 Stock Plan provides that the option price of shares issued be equal to the market price on the date of grant. All options expire 10 years after the date of grant. The 2001 Stock Plan provide for the issuance of up to 4,362,868 share of KCS common stock.

Other Plans. Shortly after its formation in May 1988, the Company adopted, among other benefit programs, an employee stock purchase plan and a savings and investment plan. While the shareholders of KCS's former parent company did not specifically vote to approve these plans, they did approve a plan authorizing the spin-off and formation of KCS which included provisions stating the intent to adopt benefit plans similar to those of the former parent.

Employee Stock Purchase Plan. Under the employee stock purchase plan, eligible employees and directors may purchase full shares from the Company at a price per share equal to 90% of the market value determined by the closing price on the date of purchase. The maximum annual purchase is the number of shares costing no more than 10% of the eligible employee's annual base salary, and for directors, 6,000 shares.

Savings and Investment Plan. Under the savings and investment plan, eligible employees may contribute a portion of their compensation, as defined, to the savings plan, subject to certain IRS limitations. The Company may make matching contributions, which have been set by the Board of Directors at 50% of the employee's contribution (up to 6% of the employee's compensation, subject to certain regulatory limitations).

The savings plan also contains a profit-sharing component whereby the Board of Directors may declare annual discretionary profit-sharing contributions. The Company's matching contributions and discretionary profit-sharing contributions vest over a four-year employment period. Once the four-year employment period has been satisfied, all Company matching contributions and discretionary profit-sharing contributions vest immediately.

Item 6. *Selected Financial Data*

The following table sets forth the Company's selected financial data for each of the five years ended December 31, 2002.

	2002(1)	2001	2000	1999	1998(2)
	Dollars in thousands (except per share data)				
Revenue	$118,819	$191,991	$ 191,989	$ 138,618	$ 131,324
Net income (loss)	(10,114)	65,579	41,523	4,340	(296,520)
Income (loss) available for common stockholders	(11,142)	63,818	41,523	4,340	(296,520)
Total assets	268,133	346,726	347,335	284,932	308,878
Debt	186,774	204,800	351,705	381,819	410,335
Redeemable convertible preferred stock	12,859	15,589	—	—	—
Stockholders' deficit	(42,716)	(39,460)	(108,320)	(149,843)	(154,204)
Per common share:					
Basic Income (Loss)	(0.31)	2.02	1.42	0.15	(10.08)
Diluted Income (Loss)	(0.31)	1.69	1.42	0.15	(10.08)
Dividends	—	—	—	—	$ 0.08

(1) Includes a $15.9 million non-cash writedown to zero of the book value of net deferred tax assets and a $6.2 million non-cash charge for the cumulative effect of an accounting change related to the amortization method of oil and gas properties.

(2) Includes $174.5 million after tax non-cash ceiling test writedowns of oil and gas assets and a $113.9 million writedown of the book value of net deferred tax assets. Together, these adjustments accounted for $288.4 million, or $9.80 per share, of the 1998 loss.

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

The following is a discussion and analysis of our financial condition and results of operations and should be read in conjunction with the Consolidated Financial Statements (including the notes thereto) included elsewhere in this Form 10-K.

Forward-looking Statements

The information discussed in this annual report on Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Exchange Act. All statements, other than statements of historical facts, included herein concerning, among other things, planned capital expenditures, increases in oil and gas production, the number of anticipated wells to be drilled after the date hereof, the Company's financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as "expect," "estimate," "project," "plan," "believe," "achievable," "anticipate" and similar terms and phrases. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties, and the Company can give no assurance that such expectations will prove to be correct. The Company's actual results could differ materially from those anticipated in these forward-looking statements as a result of certain factors, including:

- the timing and success of the Company's drilling activities;
- the volatility of prices and supply and demand for oil and gas;
- the numerous uncertainties inherent in estimating quantities of oil and gas reserves and actual future production rates and associated costs;
- the usual hazards associated with the oil and gas industry (including blowouts, cratering, pipe failure, spills, explosions and other unforeseen hazards);
- changes in regulatory requirements; or
- if underlying assumptions prove incorrect.

These and other risks are described in greater detail in "Oil and Gas Risk Factors" included elsewhere in this Form 10-K.

All forward-looking statements attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by such factors. Other than required under the securities laws, the Company does not assume a duty to update these forward looking statements.

General

Our main objective in 2002 was to position the Company to meet our Senior Note obligations due January 15, 2003. In order to meet this objective, we curtailed our drilling and overall capital expenditure programs and sold certain non-core assets. These actions positioned us to reduce debt and negotiate the financing necessary to pay off the remaining portion of the maturing Senior Notes during a difficult period in the capital markets. Although the asset sales and curtailed drilling and capital expenditure programs resulted in lower production and reserves in 2002, we exited the year in a stronger financial position, with increased financial flexibility, a focused asset base in our core areas, and a quality multi-year drilling prospect inventory.

On January 14, 2003, we completed the arrangements necessary to amend and restate our existing credit agreement with a group of institutional lenders. The amended facility provides $90.0 million of borrowing capacity, $40.0 million in the form of a term loan and $50.0 million in revolving facilities, and matures on October 3, 2005. Initial proceeds of $69.3 million were used primarily to pay off the balance of the maturing Senior Note obligations, leaving $20.7 million of available borrowing capacity under the facility.

Prices for oil and natural gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control. These factors include political conditions in the Middle East and elsewhere, domestic and foreign supply of oil and natural gas, the level of industrial and consumer demand, weather conditions and overall economic conditions.

Application of Critical Accounting Policies

The discussion and analysis of our financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect our financial position and results of operations. Our significant accounting policies are described in Note 1 to Consolidated Financial Statements contained elsewhere in this annual report on Form 10-K. Certain of these accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We discussed the development, selection, and disclosure of each of these critical accounting estimates with our audit committee. The following discussion details the more significant accounting policies, estimates and judgments.

Full Cost Method of Accounting for Oil and Gas Operations

The accounting for our business is subject to accounting rules that are unique to the oil and gas industry. There are two allowable methods of accounting for oil and gas business activities, the successful efforts method and the full cost method. We have elected to use the full cost method to account for our investment in oil and gas properties. Under this method, the Company capitalizes all acquisition, exploration and development costs into one cost center. Such costs include lease acquisitions, geological and geophysical services, drilling, equipment, and salaries, benefits and other internal costs directly attributable to these activities. These costs are then amortized over the remaining life of the aggregate oil and gas reserves using the "unit-of-production" method of calculating depletion expense discussed below under "Amortization of Oil and Gas Properties". The full cost method embraces the concept that dry holes and other expenditures that fail to add reserves are intrinsic to the oil and gas exploration business, and are therefore capitalized. Although some of these costs will ultimately result in no additional reserves, they are part of a program from which we expect the benefits of successful wells to more than offset the costs of any unsuccessful ones. As a result, we believe that the full cost method of accounting to be appropriate and reflective of the economics of our programs for the acquisition, exploration and development of oil and gas reserves. Under the successful efforts method, costs of exploratory dry holes and geological and geophysical exploration costs that would be capitalized under the full cost method would be charged against earnings during the periods in which the occur. Accordingly, our financial position and results of operations may have been significantly different had we used the successful efforts method of accounting for our oil and gas investments.

Oil and Gas Reserve Estimates

Estimates of our proved oil and gas reserves are based on the quantities of oil and gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. The accuracy of any oil and gas reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. For example, we must estimate the amount and timing of future operating costs, severance taxes, development costs, and workover costs, all of which may in fact vary considerably from actual results. In addition, as prices and cost levels change from year to year, the estimate of proved reserves also change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves.

Despite the inherent imprecision in these engineering estimates, estimates of our oil and gas reserves are used throughout our financial statements. For example, since we use the unit-of-production method, the amortization rate of our capitalized oil and gas properties incorporates the estimated units-of-production attributable to the estimates of proved reserves. Our oil and gas properties are also subject to a "ceiling" limitation based in part on the quantity of our proved reserves. See Note 1 to Consolidated Financial Statements. Finally, these reserves are the basis for our supplemental oil and gas disclosures.

The estimates of our proved oil and gas reserves have been prepared or audited by NSA, independent petroleum engineers.

Amortization of Oil and Gas Properties

Effective January 1, 2002, KCS began amortizing the capitalized costs related to oil and gas properties under the unit-of-production basis ("UOP") method using proved oil and gas reserves. See Note 1 to Consolidated Financial Statements. Under the UOP method, the amortization rate is computed based on the portion of our reserves produced, including reserves and production associated with the Production Payment. This rate is applied to the amortizable base of our oil and gas properties (the net book value of oil and gas properties less the costs of unevaluated oil and gas properties plus estimated future costs to develop the oil and gas properties). The calculation of DD&A requires the use of significant estimates pertaining to oil and gas reserves and future development costs.

Bad Debt Expense

We routinely assess the recoverability of all material trade and other receivables to determine their collectibility. Many of our receivables are from joint interest owners on properties we operate. Thus, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. The Company markets the majority of its production and these receivables are generally collected within a month. The receivables for the remaining production is typically collected within two months. We accrue a reserve for a receivable when, based on the judgment of management, it is probable that such receivable will not be collected in full and the amount of any reserve required can be reasonably estimated.

Revenue Recognition

Gas imbalances can arise on properties for which two or more owners have the right to take production "in-kind." In a typical gas balancing arrangement, each owner is entitled to an agreed-upon percentage of the property's total production. However, at any given time, the amount of gas sold by each owner may differ from its allowable percentage. Two principal accounting practices have evolved to account for gas imbalances. These methods differ as to whether revenue is recognized based on the actual sale of gas (sales method) or an owner's entitled share of the current period's production (entitlement method). We have elected to use the sales method. Under this method, a liability is recognized for an imbalance only when the estimated remaining reserves will not be sufficient to enable the under produced owner to recoup its entitled share through future production. Had we used the entitlement method, our reported revenues could have been materially different.

Income Taxes

We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. Numerous judgments and assumptions are inherent in the estimation of future taxable income, including assumptions with respect to our future operating results (particularly as related to volatile oil and gas prices). Such judgments and assumptions are inherently imprecise and may prove to be materially incorrect in the future.

Asset Retirement Obligations

We have significant obligations to remove equipment and restore land at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells. The estimated undiscounted costs, net of equipment salvage value, of dismantling and removing these facilities are accrued over the production life of the oil and gas property as additional DD&A. Estimating the future asset removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and because contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are political, environmental, safety and public relations considerations. In addition, the Financial Accounting Standards Board (FASB) has recently issued SFAS No. 143, "Accounting for Asset Retirement Obligations," (SFAS No. 143), which significantly changes the method of accruing for costs, associated with the retirement of fixed assets, that an entity is legally obligated to incur.

SFAS No. 143 requires us to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the periods in which it is incurred. When the liability is initially recorded, we increase the carrying amount of the related long-lived asset. The liability is accreted to the fair value at the time of settlement over the useful life of the asset, and the capitalized cost is depreciated over the useful life of the related asset. We adopted SFAS No. 143 effective on January 1, 2003. As a result, net property, plant and equipment was increased by $10.2 million, an asset retirement obligation of $11.1 million was recorded and a $0.9 million charge against net income will be reported in the first quarter of 2003 as a cumulative effect of a change in accounting principle.

Derivatives

We use commodity derivative contracts on a limited basis to manage our exposure to oil and gas price volatility. KCS accounts for its commodity derivative contracts in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133). Realized gains and losses from our cash flow hedges, including terminated contracts, are generally recognized in oil and gas production revenue when the hedged volumes are produced and sold. We do not enter into derivative or other financial instruments for trading purposes.

Results of Operations for the Years Ended December 31, 2002, 2001 and 2000

Results of Operations

Income before income taxes for 2002 was $9.8 million compared to $57.2 million in 2001. Dramatically lower natural gas prices, lower non-oil and gas revenue and lower production were partially offset by significantly lower operating, reorganization and interest expenses. Income tax expense for 2002 was $13.8 million compared to an income tax benefit of $8.4 million in 2001. As a result of the non-cash income tax expense in 2002 (see Note 8 to Consolidated Financial Statements), we reported a net loss before cumulative effect of accounting change of $3.9 million, or $0.14 per basic and diluted share. The cumulative effect of accounting change related to the amortization method for oil and gas properties was a $6.2 million loss, or $0.17 per basic and diluted share. Net loss in 2002 was $10.1 million, or $0.31 per basic and diluted share compared to net income of $65.6 million, or $2.02 per basic share ($1.69 per diluted share) in 2001.

Net income for 2001 was $65.6 million, or $2.02 per basic share ($1.69 per diluted share), compared to $41.5 million, or $1.42 per basic and diluted share in 2000. This increase was attributable to higher average realized natural gas prices, increased working interest production, higher other revenue and lower interest expense partially offset by lower production from the VPP program, lower oil prices and higher operating expenses. Reorganization items in 2001 were $2.9 million compared to $15.4 million in 2000.

Revenue

	2002	2001	2000
Production:(a)			
Gas (Mmcf)	29,672	36,873	41,089
Oil (Mbbl)	1,003	1,230	1,306
Liquids (Mbbl)	288	373	264
Summary (Mmcfe)			
Working interest	34,959	41,966	38,642
Purchased VPP	2,458	4,525	11,866
Total	37,417	46,491	50,508
Average Price:(b)			
Gas (per Mcf)	$ 3.25	$ 3.90	$ 3.69
Oil (per bbl)	20.52	20.67	27.35
Liquids (per bbl)	10.05	13.74	13.31
Total (per Mcfe)	$ 3.21	$ 3.75	$ 3.77
Revenue:			
Gas	$ 96,531	$143,882	$151,293
Oil	20,578	25,428	35,711
Liquids	2,893	5,124	3,507
Total	$120,002	$174,434	$190,511

(a) Production includes 11,196 Mmcfe and 15,716 Mmcfe in 2002 and 2001, respectively, dedicated to the Production Payment sold in February 2001. See Notes 1 and 2 to Consolidated Financial Statements.

(b) Includes the effects of hedging and, in 2002 and 2001, amortization of deferred revenue attributed to deliveries under the Production Payment sold in February 2001. See Note 1 to Consolidated Financial Statements.

Gas Revenue. In 2002, gas revenue was $96.5 million compared to $143.9 million in 2001 as a result of a 17% decrease in realized natural gas prices and a 20% decline in production. The production decline was primarily due to the sale of oil and gas properties, expiration of certain VPP's and no additional investment in the VPP program in 2000 or 2001 due to limited capital availability. Furthermore, the natural decline of producing properties was not fully offset by new production largely due to the reduction in the capital investment program. See "Liquidity and Capital Resources".

In 2001, gas revenue was $143.9 million compared to $151.3 million in 2000. Higher natural gas prices during the first half of the year and a 9% increase in working interest production were offset by a 7.4 Bcf decrease in scheduled production from the VPP program and the dramatic decline in natural gas prices during the second half of 2001. Average realized gas prices during the first half of 2001 were $4.55 per Mcf compared to $3.19 during the second half of the year. The decrease in VPP production reflects the expiration of certain VPPs, limited investment in the program since 1999 and no investment in 2001.

Oil and Liquids Revenue. In 2002, oil and liquids revenue decreased $7.1 million to $23.5 million primarily due to a 19% decrease in production. The decrease in production in 2002 was attributable to the sale of oil and gas properties and the natural declines of producing properties.

In 2001, oil and liquids revenue decreased $8.7 million to $30.6 million primarily due to a 24% decrease in average realized oil prices.

Other Revenue, net. Other revenue, net decreased from $17.6 million in 2001 to a net cost of $1.2 million in 2002. Of the $17.6 million in 2001, $9.3 million was from the sale of emission reduction credits and $7.7 million was from non-cash gains on derivative instruments that were not designated as oil and gas hedges when we adopted SFAS No. 133 (see Note 9 to Consolidated Financial Statements), and the remainder was primarily attributable to marketing and transportation revenue incidental to our oil and gas operations. In 2002, the net cost of $1.2 million was primarily attributable to gas marketing and transportation activities.

In 2000, other revenue, net included $1.0 million from the settlement of certain claims related to a 1996 acquisition and $0.7 million from the sale of emission reduction credits.

Lease Operating Expenses

For the year ended December 31, 2002, lease operating expenses decreased 17% to $25.2 million, compared to $30.5 million in 2001. Increased focus on cost reductions and operating efficiency along with the sale of certain properties contributed to the reductions.

For the year ended December 31, 2001, lease operating expenses increased 10% to $30.5 million, compared to $27.8 million in 2000. The increased costs in 2001 reflect start-up costs associated with our Hartland gas processing plant in Michigan incurred during the first quarter of the year, higher ad valorem taxes, higher working interest production, and increased costs of workovers on oil and gas wells in order to maximize production during the first half of 2001 when natural gas prices were high.

Production Taxes

Production taxes, which are generally based on a percentage of revenue (excluding revenue from the VPP program), decreased $2.6 million to $5.6 million in 2002 compared to $8.2 million in 2001 due to lower oil and gas revenue associated with the decrease in working interest production and lower average realized prices.

Production taxes increased $1.6 million to $8.2 million in 2001, compared to $6.6 million in 2000 due to higher average natural gas prices and the increase in working interest production.

General and Administrative Expenses

General and administrative expenses decreased $0.6 million to $8.3 million in 2002, compared to $8.9 million in 2001 as a result of lower labor cost associated with a reduced work force, partially offset by an increase in insurance premiums and employment severance payments.

General and administrative expenses were $8.9 million in 2001, which included approximately $1.4 million of costs associated with the retention bonus program for employees other than senior management that was put in place in October 2000 in order for us to retain our employees during the reorganization process. Excluding the effect of the retention bonus program, G&A in 2001 decreased 6% compared to 2000 as a result of lower salaries and wages due to a reduced workforce.

Stock Compensation

Stock compensation was $0.8 million in 2002 compared to $1.4 million in 2001. These amounts reflect the non-cash amortization of restricted stock grants issued to our employees under the 2001 Stock Plan. The 2001 expense includes incremental costs associated with initial grants made upon our emergence from Chapter 11 to compensate for a portion of stock options previously issued but cancelled in connection with the plan of reorganization.

Bad Debt Expense

We routinely assess the collectibility of our trade and other receivables. Bad debt expense was $0.2 million in 2002, which represents an allowance against certain joint interest receivables, the collection of which has been determined to be doubtful.

Bad debt expense was $4.1 million in 2001, primarily with respect to an allowance against receivables due from Enron entities, which are now in bankruptcy, for oil and gas sales and derivative instruments. We ceased all sales to Enron entities after November 2001. See Note 9 to Consolidated Financial Statements for information with respect to derivative contracts that we had with Enron entities.

Depreciation, Depletion and Amortization (DD&A)

Effective January 1, 2002, we began amortizing our oil and gas properties using the UOP method based on proved reserves. See Note 1 to Consolidated Financial Statements. This change resulted in additional amortization of $6.2 million through December 31, 2001, which is classified as a cumulative effect of accounting change, net of tax, in 2002. For the year ended December 31, 2002, DD&A decreased $9.1 million to $49.3 million. The decrease reflects reduced production and a lower depletable base.

For the year ended December 31, 2001, DD&A increased $7.9 million to $58.3 million, reflecting an increase in the DD&A rate largely due to the dramatic decline in natural gas prices during the second half of 2001 and a higher depletable base.

Interest and Other Income

Interest and other income was $0.3 million in 2002 compared to $1.3 million in 2001 and $0.1 million in 2000. These amounts primarily represent interest income earned on accumulated cash and cash equivalents. In 2000, we also reported $1.0 million of interest income associated with accumulated cash and cash equivalents as a component of "Reorganization items" pursuant to Statement of Position ("SOP") 90-7.

Interest Expense

Interest expense was $19.9 million in 2002 compared to $21.8 million in 2001 and $41.5 million in 2000. The lower interest expense in 2002 reflects the trend of lowering outstanding debt and, to a lesser extent, lower interest rates on our credit facility, partially offset by a $1.1 million write off of deferred financing costs in December 2002 (See Note 5 to Consolidated Financial Statements). Interest expense in 2000 includes $4.2 million of interest on past due interest with respect to our Senior Notes and Senior Subordinated Notes in accordance with our plan of reorganization.

Reorganization Items

We completed our reorganization in 2001 and consequently there were no reorganization items in 2002. For the year ended December 31, 2001; we recorded $2.9 million of reorganization items, primarily for legal and financial advisory services in connection with the completed Chapter 11 proceedings.

During 2000, we recorded $15.4 million of net reorganization items, $6.1 million of which was a non-cash write-off of deferred debt issuance costs associated with the Senior Notes and Senior Subordinated Notes in accordance with SOP 90-7. The balance reflects restructuring costs of $10.3 million, primarily for legal and financial advisory services. During 2000, we earned interest income of $1.0 million on cash accumulated during the Chapter 11 proceedings, which partially offset the foregoing charges.

Income Taxes

Income tax expense in 2002 was $13.8 million resulting from a $15.9 million non-cash increase in our valuation allowance against net deferred tax assets at June 30, 2002, partially offset by a $2.1 million non-cash tax benefit (decrease in the valuation allowance) primarily associated with certain derivative instruments initially accounted for as a component of the cumulative effect of a change in accounting principle upon adoption of SFAS No. 133. As discussed in Note 8 to Consolidated Financial Statements, we routinely assess the valuation allowance against net deferred tax assets. During the second quarter of 2002, we concluded that the $15.9 million increase in the valuation allowance, which reduced the carrying value of net deferred assets to zero, was appropriate. In making that assessment, we considered several factors, including future projections of taxable income, which reflected relatively low natural gas and oil prices at that time, and the January 2003 maturity of our Senior Note obligations that required refinancing. While the Senior Note obligations have now been refinanced and natural gas and oil prices have improved significantly in recent months, we continue maintain the valuation allowance against 100% of our net deferred tax assets. We made this determination since, at this time, it is difficult to project the necessary levels of future taxable income with sufficient certainty, considering the significant volatility in natural gas and oil prices and that the current higher price environment has existed for only a short period. We will continue to assess the necessity for the valuation allowance, and to the extent it is determined that such allowance is no longer required, the tax benefit of the remaining net deferred tax assets will be recognized in the future.

In connection with the adoption of SFAS No. 133 on January 1, 2001, we recorded a liability of $43.8 million representing the fair market value of our derivative instruments upon adoption and an after-tax charge to other comprehensive income of $28.5 million from the cumulative effect of a change in accounting principle. During 2001, we reclassified $23.9 million of the liability as a non-cash reduction to oil and gas revenues and reduced the valuation allowance related primarily to net operating losses, for a related tax benefit of $8.4 million.

No income taxes were recorded in 2000 related to pre-tax book income as a portion of the valuation allowance account established in 1998 was reversed due to our assessment of our ability to utilize net operating loss carryforwards. See Note 8 to Consolidated Financial Statements.

Liquidity and Capital Resources

Our main objective in 2002 was to position the Company to meet our Senior Note obligations due January 15, 2003. In order to meet this objective, we curtailed our drilling and overall capital expenditure programs and sold certain non-core assets. These actions positioned us to reduce debt and negotiate the financing necessary to pay off the remaining portion of the maturing Senior Notes during a difficult period in the capital markets. Although the asset sales and curtailed drilling and capital expenditure programs resulted in lower production and reserves in 2002, we exited the year in a stronger financial position, with increased financial flexibility, a focused asset base in our core areas, and a quality multi-year drilling prospect inventory.

On January 14, 2003, we completed the arrangements necessary to amend and restate our existing credit agreement ("Credit Agreement") with a group of institutional lenders. Initial proceeds of $69.3 million were used primarily to pay off the balance of the maturing Senior Note obligations, leaving $20.7 million of available borrowing capacity under the facility.

We reduced lifting costs (lease operating expenses and production taxes) by 20% and general and administrative expenses by 7% in 2002 and expect further reductions in 2003. With the completion of the financing and the implementation of this cost reduction program, we believe that we are well positioned to capitalize on the strong natural gas price environment and to focus on developing our prospect inventory to grow reserves and production in our core areas.

We have reduced debt from a peak of $425.0 million in early 1999 to $194.3 million on January 15, 2003 and are committed to further debt reduction.

Cash Flow from Operating Activities

Net cash provided by operating activities for 2002 was $20.1 million compared to $183.4 million in 2001. The 2001 cash provided by operating activities was significantly impacted by the execution of the Plan of reorganization which included net proceeds of $175.0 million from the Production Payment sold in February 2001 (see Notes 1 and 2 to Consolidated Financial Statements), the payment of $71.5 million of interest expense ($49.1 million of which pertained to prior years) and the $28.0 million cost of terminating certain derivative instruments in connection with the emergence from Chapter 11. The 2002 cash provided by operating activities was negatively impacted by lower realized natural gas prices and lower production as discussed above.

Net cash provided by operating activities was $183.4 million in 2001 compared to $128.0 million in 2000. In addition to the impact of the execution of the Plan of reorganization, 2001 was favorably impacted by higher natural gas prices and higher other revenue. In 2000, the net increase in accounts payable and accrued liabilities, inclusive of accrued interest was primarily due to the suspension of interest payments on the Senior Notes and Senior Subordinated Notes during the period of reorganization and to accrued restructuring costs.

Investing Activities

Capital expenditures for the year ended December 31, 2002 were $47.5 million, of which, $30.3 million was for development activities, $4.8 million for the acquisition of proved reserves and $12.4 million for lease acquisitions, seismic surveys and exploratory drilling.

Capital expenditures for the year ended December 31, 2001 were $87.2 million, of which $42.9 million was for development activities, $26.8 million for the acquisition of proved reserves, $15.3 million for lease acquisitions, seismic surveys and exploratory drilling and $2.2 million for other assets.

Capital expenditures for the year ended December 31, 2000 were $69.1 million of which $36.0 million was for development activities, $7.3 million for the acquisition of proved reserves and $19.3 million for lease acquisitions, seismic surveys and exploratory drilling. Other capital expenditures were $6.5 million, of which $6.2 million was for the construction of a gas processing facility.

Capital spending for 2003 has initially been budgeted at $50 million. The 2003 capital program is expected to be funded with internally generated cash.

Credit Facilities

The Credit Agreement, which matures on October 3, 2005, provides up to $90.0 million of borrowing capacity, $40.0 million in the form of a term loan, a $30.0 million revolving "A" facility and a $20.0 million revolving "B" facility. Borrowing capacity is subject to monthly borrowing base calculations with respect to the value of certain of the Company's oil and gas assets. Initial proceeds of $69.3 million were used primarily to pay off the Company's maturing Senior Note obligations. The term loan and the revolving "B" facility, which may be prepaid at any time without penalty, bear interest based on the prime rate, initially equating to 9.0%, and increasing annually. The revolving "A" facility bears, at the Company's option, an interest rate of LIBOR plus 2.75% to 3.0% or prime plus 0.5% to 0.75%, depending on utilization. The revolving "A" facility requires a commitment fee of 0.5% per annum on the unused availability and carries an early termination penalty of 1.5% in the first year and 1% in the second year. Financing fees associated with the amended and restated agreement have been recorded as deferred charges and are being amortized as interest expense over the life of the Credit Agreement. The remaining deferred financing fees associated with the original agreement were written off to interest expense in December 2002. Certain other fees are also payable under the Credit Facility based on services provided. Substantially all of the Company's assets are pledged to secure the Credit Agreement.

The Credit Agreement contains various restrictive covenants including ratios of debt to EBITDA, interest coverage, fixed charge coverage and liquidity. The Credit Agreement also contains provisions that require the hedging of a portion of the Company's oil and gas production, payment upon a change of control, restrictions on the payment of dividends and certain other restricted payments and places limitations on the incurrence of additional debt, capital expenditures, the sale of assets, and the repurchase of Senior Subordinated Notes. Any repayment made on the term loan portion of the facility will permanently reduce the funds available under the Credit Agreement.

Contractual Cash Obligations

The following table quantifies our future contractual obligations as of December 31, 2002.

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
	(In thousands of dollars)				
Long-term debt	186,774	—	61,774	125,000	—
Redeemable convertible preferred stock(a)	12,859	—	—	—	12,859
Operating leases	3,463	1,515	1,667	281	—
Unconditional purchase obligations	9,131	2,912	5,537	682	—
	212,227	4,427	68,978	125,963	12,859

(a) Subsequent to December 31, 2002, $3,750,000 of convertible preferred stock was exchanged for our common stock. The preferred stock is redeemable at our option if the closing price of the common stock exceeds $6.00 per share for 25 out of 30 consecutive trading days or at the election of holders of a majority of the outstanding shares of the preferred stock on or after January 31, 2009. See Notes 5, 6 and 7 to Consolidated Financial Statements.

Other Commercial Commitments

In connection with the Production Payment discussed in Notes 1 and 2 to the Consolidated Financial Statement, we have obligations to deliver 6.8 Bcfe in 2003, 5.2 Bcfe in 2004, 3.9 Bcfe in 2005 and 0.3 Bcfe in 2006. At December 31, 2002, we had $2.4 million of surety bonds that remain outstanding until specific events or projects are completed and claims are settled. In February 2003, a one year $2.0 million standby letter of credit was issued under the Credit Agreement in support of our hedging program.

New Accounting Principles

In July 2001, the FASB issued Statement of Financial Accounting Standard ("SFAS No. 143"), "Accounting for Asset Retirement Obligations". SFAS No. 143 requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the periods in which it is incurred. When the liability is initially recorded, the entity increases the carrying amount of the related long-lived asset. The liability is accreted to the fair value at the time of settlement over the useful life of the asset, and the capitalized cost is depreciated over the useful life of the related asset. The Company adopted SFAS No. 143 effective on January 1, 2003. As a result, property, plant and equipment was increased by $10.2 million, an additional asset retirement obligation of $11.1 million was recorded and a $0.9 million charge against net income will be reported in the first quarter of 2003 as a cumulative effect of a change in accounting principle.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS No. 144"). SFAS No. 144 addresses the financial accounting and reporting for the impairment or disposal of long-lived assets. SFAS No. 144 supersedes SFAS No. 121 but retains its fundamental provisions for the (a) recognition/measurement of impairment of long-lived assets to be held and used and (b) measurement of long-lived assets to be disposed of by sale. SFAS No. 144 also supersedes the accounting/reporting provisions of APB Opinion No. 30 for segments of a business to be disposed of but retains the requirement to report discontinued operations separately from continuing operations and extends that reporting to a component of an entity that either has been disposed of or is classified as held for sale. The Company adopted the provisions of SFAS No. 144 effective January 1, 2002, with no significant impact.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

Derivative Instruments. The Company's major market risk exposure is to oil and gas prices, which have historically been volatile. Realized prices are primarily driven by the prevailing worldwide price for crude oil and regional spot prices for natural gas production. The Company has utilized, and may continue to utilize, derivative contracts, including swaps, futures contracts, options and collars to manage this price risk. The Company does not enter into derivative or other financial instruments for speculative purposes. Effective January 1, 2001, the Company adopted SFAS No. 133. See Note 9 to Consolidated Financial Statements. While these derivative contracts are structured to reduce the Company's exposure to decreases in the price associated with the underlying commodity, they also limit the benefit the Company might otherwise receive from any price increases.

At December 31, 2002, the Company had no outstanding derivative financial instruments. During February 2003, the Company invested $0.6 million in a series of derivative transactions covering 3.5 million MMbtu of gas production for April through November 2003. These instruments establish an average floor price of $4.51 and enable the Company to receive market prices up to an average cap of $5.78, approximately 26% of any price realized between $5.78 and $6.28 and 100% of any price realized above $6.28.

	Expected Maturity, 2003				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Swaps:					
Volumes (bbl)	30,000	15,000	—	—	45,000
Weighted average price ($/bbl)	$ 31.06	$ 31.06	$ —	$ —	$ 31.06
Puts/Floors:					
Volumes (MMbtu)	—	150,000	460,000	305,000	915,000
Weighted average price ($/MMbtu)	$ —	$ 4.25	$ 4.25	$ 4.25	$ 4.25
3-way collars:					
Volumes (MMbtu)	—	1,060,000	1,075,000	460,000	2,595,000
Weighted average price ($/MMbtu)					
Floor (purchased put option)	$ —	$ 4.83	$ 4.47	$ 4.40	$ 4.61
Cap 1 (sold call option)	$ —	$ 5.81	$ 5.76	$ 5.75	$ 5.78
Cap 2 (purchased call option)	$ —	$ 6.31	$ 6.26	$ 6.25	$ 6.28

In addition to the above, the Company has entered into fixed price sales contracts covering 0.7 million MMbtu at an average price of $5.08 for February through June 2003 and will deliver 6.8 Bcfe in 2003 under the Production Payment sold in February 2001 at an average price of $4.05 per Mcfe as described in Notes 1 and 2 to Consolidated Financial Statements.

For 2002, the Company delivered approximately 30% of its production under the Production Payment sold in February 2001 at an average realized price of $4.05 per Mcfe and also entered into derivative arrangements designed to reduce price downside risk for approximately 17% of the balance of its production. For the year 2001, the Company delivered approximately 34% of its production under the Production Payment and also entered into derivative contracts which covered approximately 30% of the balance of its production.

Interest Rate Risk. The Company uses fixed and variable rate long-term debt to finance its capital spending program and for general corporate purposes. These variable rate debt instruments expose the Company to market risk related to changes in interest rates. The Company's fixed rate debt and the associated weighted average interest rate was $186.3 million at 9.6% on December 31, 2002 and $204.8 million at 9.7% on December 31, 2001. The Company's variable rate debt and weighted average interest rate was $0.5 million at 5.3% on December 31, 2002. The Company had no variable rate debt on December 31, 2001. The table below presents principal cash flows and related average interest rates by expected maturity dates for the Company's debt obligations at December 31, 2002. The fixed rate debt due in 2003 was replaced with variable rate debt on January 14, 2003. See Note 5 to Consolidated Financial Statements.

	Expected Maturity Date				Fair Value at December 31, 2002
	2003	2004	2005	2006	
	(Dollar amounts in millions)				
Long-term debt					
Fixed rate	—	—	$ 61.3	$125.0	$155.7
Average interest rate	—	—	11.000%	8.875%	
Variable rate	—	—	$ 0.5	—	$ 0.5
Average interest rate	—	—	5.250%	—	

Item 8. *Financial Statements and Supplementary Data*

REPORT OF INDEPENDENT PUBLIC AUDITORS

To the Board of Directors and Stockholders of KCS Energy, Inc.:

We have audited the accompanying consolidated balance sheet of KCS Energy, Inc. and subsidiaries as of December 31, 2002 and the related consolidated statements of operations, stockholders' deficit, and cash flows for the year then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. The consolidated financial statements of KCS Energy, Inc. and subsidiaries as of December 31, 2001, and for each of the two years in the period then ended, were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on those financial statements in their report dated March 13, 2002. Their report, however, had an explanatory paragraph indicating that the Company changed its method of accounting for derivative instruments and hedging activities, effective January 1, 2001, to conform with Statement of Financial Accounting Standard No. 133, "Accounting for Derivative Instruments and Hedging Activities."

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

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

As discussed above, the consolidated financial statements of KCS Energy, Inc. and subsidiaries as of December 31, 2001, and for each of the two years in the period then ended, were audited by other auditors who have ceased operations. As described in Note 1, effective January 1, 2002, the Company changed their method of accounting for the amortization of its oil and gas properties. These financial statements have been revised to reflect the pro forma effect on income available to common stockholders and earnings per share as if the Company had applied the new amortization method to its oil and gas properties during 2001 and 2000. Our audit procedures with respect to these adjustments in Note 1 for 2001 and 2000 included (a) agreeing the previously reported income available to common stockholders and basic and diluted earnings per share to the previously issued financial statements, (b) agreeing the adjustments to reported income available to common stockholders, representing changes in the amortization method, to the Company's underlying records obtained from management, and (c) testing the mathematical accuracy of the reconciliation of adjusted income available to common stockholders and the related per-share amounts. In our opinion, such adjustments are appropriate and have been properly applied. However, we were not engaged to audit, review, or apply any procedures to the 2001 and 2000 consolidated financial statements of KCS Energy Inc. and subsidiaries, other than with respect to such adjustments and, accordingly, we do not express an opinion or any other form of assurance on the 2001 and 2000 consolidated financial statements taken as a whole.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 27, 2003

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To KCS Energy, Inc.:

We have audited the accompanying consolidated balance sheets of KCS Energy, Inc. (a Delaware Corporation) and subsidiaries as of December 31, 2001 and 2000, and the related statements of consolidated operations, stockholders' (deficit) equity and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of KCS Energy, Inc. and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States.

As explained in Note 9 to the consolidated financial statements, effective January 1, 2001, the Company changed its method of accounting for derivative instruments and hedging activities to conform with Statement of Financial Accounting Standard No. 133, "Accounting for Derivative Instruments and Hedging Activities."

/s/ ARTHUR ANDERSEN LLP

Houston, Texas
March 13, 2002

THIS IS A COPY OF AN ACCOUNTANTS' REPORT PREVIOUSLY ISSUED BY ARTHUR ANDERSEN LLP, THE COMPANY'S FORMER INDEPENDENT PUBLIC ACCOUNTANTS, IN CONNECTION WITH THE COMPANY'S FORM 10-K FILED APRIL 1, 2002, AND HAS NOT BEEN REISSUED BY ARTHUR ANDERSEN SINCE THAT DATE. SEE EXHIBIT 23(ii) FOR FURTHER INFORMATION. THE COMPANY IS INCLUDING THIS COPY OF THE ARTHUR ANDERSEN LLP AUDIT REPORT PURSUANT TO RULE 2-02(e) OF REGULATION S-X UNDER THE SECURITIES ACT OF 1933, AS AMENDED.

KCS ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED OPERATIONS

	For the Year Ended December 31,		
	2002	2001	2000
	(Amounts in thousands, except per share data)		
Oil and gas revenue	$120,002	$174,434	$190,511
Other revenue, net	(1,183)	17,557	1,478
Total revenue	118,819	191,991	191,989
Operating costs and expenses			
Lease operating expenses	25,246	30,456	27,801
Production taxes	5,589	8,195	6,605
General and administrative expenses	8,255	8,885	8,417
Stock compensation	782	1,419	—
Bad debt expense	215	4,074	400
Restructuring costs	—	—	—
Depreciation, depletion and amortization	49,251	58,314	50,451
Total operating costs and expenses	89,338	111,343	93,674
Operating income	29,481	80,648	98,315
Interest and other income	279	1,319	101
Interest expense (contractual interest for 2000 was $36,220)	(19,945)	(21,799)	(41,460)
Income before reorganization items and income taxes	9,815	60,168	56,956
Reorganization items			
Write-off of deferred debt issuance costs related to senior notes and senior subordinated notes	—	—	(6,132)
Financial restructuring costs	—	(3,175)	(10,334)
Interest income	—	227	1,033
Reorganization items, net	—	(2,948)	(15,433)
Income before income taxes	9,815	57,220	41,523
Federal and state income tax expense (benefit)	13,763	(8,359)	—
Net income (loss) before cumulative effect of accounting change	(3,948)	65,579	41,523
Cumulative effect of accounting change, net of tax	(6,166)	—	—
Net income (loss)	(10,114)	65,579	41,523
Dividends and accretion of issuance costs on preferred stock	(1,028)	(1,761)	—
Income (loss) available to common stockholders	$(11,142)	$ 63,818	$ 41,523
Earnings (loss) per share of common stock — basic			
Before cumulative effect of accounting change	$ (0.14)	$ 2.02	$ 1.42
Cumulative effect of accounting change	(0.17)	—	—
Earnings (loss) per share of common stock — basic	$ (0.31)	$ 2.02	$ 1.42
Earnings (loss) per share of common stock- diluted			
Before cumulative effect of accounting change	$ (0.14)	$ 1.69	$ 1.42
Cumulative effect of accounting change	(0.17)	—	—
Earnings (loss) per share of common stock — diluted	$ (0.31)	$ 1.69	$ 1.42
Average shares outstanding for computation of earnings (loss) per share			
Basic	35,834	31,668	29,266
Diluted	35,834	38,828	29,305

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

KCS ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2002	December 31, 2001
	(Amounts in thousands, except share and per share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 6,935	$ 22,927
Trade accounts receivable, less allowance for doubtful accounts of $4,678 in 2002 and $4,190 in 2001	16,863	20,342
Prepaid drilling	1,362	4,122
Other current assets	2,034	2,596
Current assets	27,194	49,987
Property, plant and equipment		
Oil and gas properties, full cost method, less accumulated DD&A — 2002 $891,124; 2001 $837,096	231,579	268,517
Other property, plant and equipment, at cost less accumulated depreciation — 2002 $10,415; 2001 $9,026	8,715	10,160
Property, plant and equipment, net	240,294	278,677
Deferred charges and other assets	645	2,142
Deferred taxes	—	15,920
	$ 268,133	$ 346,726
LIABILITIES AND STOCKHOLDERS' DEFICIT		
Current liabilities		
Accounts payable	$ 23,854	$ 26,041
Accrued interest	8,174	9,089
Accrued drilling cost	2,861	6,653
Other accrued liabilities	8,784	11,257
Current liabilities	43,673	53,040
Deferred credits and other liabilities		
Deferred revenue	66,582	111,880
Other	961	877
Deferred credits and other liabilities	67,543	112,757
Long-term debt		
Senior notes	61,274	79,800
Senior subordinated notes	125,000	125,000
Bank credit facility	500	—
Long-term debt	186,774	204,800
Commitments and contingencies		
Preferred stock, authorized 5,000,000 shares, issued 30,000 shares redeemable convertible preferred stock, par value $.01 per share liquidation preference $1,000 per share — 13,288 and 16,365 shares outstanding, respectively	12,859	15,589
Stockholders' deficit		
Common stock, par value $0.01 per share, authorized 75,000,000 shares; issued 38,611,816 and 36,844,495, respectively	386	368
Additional paid-in capital	167,335	162,540
Accumulated deficit	(196,315)	(185,173)
Unearned compensation	(880)	(1,292)
Accumulated other comprehensive income	(8,501)	(11,162)
Less treasury stock, 2,167,096 shares, at cost	(4,741)	(4,741)
Stockholders' deficit	(42,716)	(39,460)
	$ 268,133	$ 346,726

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

KCS ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED STOCKHOLDERS' DEFICIT

	Common Stock	Additional Paid-in Capital	Accumulated Deficit	Accumulated Other Comprehensive Income	Unearned Compensation	Treasury Stock	Comprehensive Income	(Deficit) Equity
				(Dollars in thousands)				
Balance at December 31, 1999	$314	$145,098	$(290,514)	$ —	$ —	$(4,741)	$ —	$(149,843)
Net income	—	—	41,523	—	—	—	41,523	$ 41,523
Balance at December 31, 2000	$314	$145,098	$(248,991)	$ —	$ —	$(4,741)		$(108,320)
Comprehensive income								
Net Income	—	—	65,579	—	—	—	$ 65,579	65,579
Commodity hedges, net of tax	—	—	—	(11,162)	—	—	(11,162)	(11,162)
Comprehensive income							$ 54,417	
Conversion of redeemable preferred stock	46	13,724	—	—	—	—		13,770
Stock issuances — option and benefit plans	6	2,906	—	—	(2,711)	—		201
Stock compensation expense	—	—	—	—	1,419	—		1,419
Dividends and accretion of issuance costs on preferred stock	2	812	(1,761)	—	—	—		(947)
Balance at December 31, 2001	$368	$162,540	$(185,173)	$(11,162)	$(1,292)	$(4,741)		$ (39,460)
Comprehensive income								
Net loss	—	—	(10,114)	—	—	—	$(10,114)	(10,114)
Commodity hedges, net of tax	—	—	—	2,661	—	—	2,661	2,661
Comprehensive income							$ (7,453)	
Conversion of redeemable preferred stock	10	2,932	—	—	—	—		2,942
Stock issuances — benefit plans and awards of restricted stock	4	1,049	—	—	(370)	—		683
Stock compensation expense	—	—	—	—	782	—		782
Dividends and accretion of issuance costs on preferred stock	4	814	(1,028)	—	—	—		(210)
Balance at December 31, 2002	$386	$167,335	$(196,315)	$ (8,501)	$ (880)	$(4,741)		$ (42,716)

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

KCS ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED CASH FLOWS

	For the Year Ended December 31,		
	2002	2001	2000
	(Dollars in thousands)		
Cash flows from operating activities:			
Net income (loss)	$(10,114)	$ 65,579	$41,523
Non-cash charges (credits):			
Depreciation, depletion and amortization	49,251	58,314	50,451
Amortization of deferred revenue	(45,182)	(63,089)	—
Deferred tax expense (benefit)	13,763	(8,359)	—
Cumulative effect of accounting change, net of tax	6,166	—	—
Non-cash losses on derivative instruments, net	5,041	8,085	—
Bad debt write-offs	215	4,074	400
Stock compensation	782	1,419	—
Other non-cash charges and credits, net	1,650	(233)	1,240
Reorganization items	—	2,948	15,433
Net changes in assets and liabilities:			
Proceeds from Production Payment, net	—	174,969	—
Realized losses on derivative instruments terminated in connection with Plan of reorganization	—	(27,995)	—
Trade accounts receivable	3,264	21,872	(24,013)
Other current assets	562	(1,021)	1,874
Accounts payable and accrued liabilities	(4,122)	(1,042)	19,791
Accrued interest	(915)	(49,109)	31,754
Other, net	464	(45)	(1,145)
Net cash provided by operating activities before reorganization items	20,825	186,367	137,308
Reorganization items (excluding non-cash write-off of deferred debt issuance costs)	—	(2,948)	(9,301)
Net cash provided by operating activities	20,825	183,419	128,007
Cash flows from investing activities:			
Investment in oil and gas properties	(48,596)	(85,033)	(62,598)
Proceeds from the sale of oil and gas properties	30,474	5,100	694
Investment in other property, plant and equipment	56	(2,159)	(6,480)
Net cash used in investing activities	(18,066)	(82,092)	(68,384)
Cash flows from financing activities:			
Proceeds from borrowings	500	—	292
Repayments of debt	(18,526)	(146,905)	(30,414)
Issuance of redeemable convertible preferred stock	—	28,412	—
Deferred financing costs and other, net	(725)	99	(91)
Net cash used in financing activities	(18,751)	(118,394)	(30,213)
Increase (decrease) in cash and cash equivalents	(15,992)	(17,067)	29,410
Cash and cash equivalents at beginning of year	22,927	39,994	10,584
Cash and cash equivalents at end of year	$ 6,935	$ 22,927	$39,994

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

1. Summary of Significant Accounting Policies

KCS Energy, Inc. is an independent oil and gas company engaged in the acquisition, exploration and production of natural gas and crude oil with operations predominately in the Mid-Continent and Gulf Coast regions.

Basis of Presentation

The consolidated financial statements include the accounts of KCS Energy, Inc. and its wholly owned subsidiaries ("KCS" or "Company"). All significant intercompany accounts and transactions have been eliminated in consolidation. Certain previously reported amounts have been reclassified to conform to current year presentation.

The preparation of financial statements in conformity with generally accepted accounting principles in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. During 2000 and until the Plan was effective (see Note 2), the Company conducted its business and reported its results of operations and financial position as a debtor-in-possession pursuant to Statement of Position 90-7. In connection therewith, the Company reported all liabilities deemed subject to compromise at amounts reasonably expected to be paid.

Cash Equivalents

The Company considers as cash equivalents all highly liquid investments with a maturity of three months or less from date of purchase.

Derivative Instruments

Oil and gas prices have historically been volatile. The Company has entered and may continue to enter into derivative contracts to manage the risk associated with the price fluctuations affecting it by effectively fixing the price of certain sales volumes for certain time periods. Through December 31, 2000, the Company accounted for such contracts in accordance with Statement of Financial Accounting Standard ("SFAS") No. 80 "Accounting for Futures Contracts". These contracts permitted settlement by delivery of commodities and, therefore, were not financial instruments as defined by SFAS Nos. 107 and 119. Changes in the market value of these transactions were deferred until the sale of the underlying production was recognized.

Effective January 1, 2001, the Company adopted SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133, as amended, establishes accounting and disclosure standards requiring that all derivative instruments be recorded in the balance sheet as an asset or liability, measured at fair value. It further requires that changes in a derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. To qualify as a hedge, these transactions must be formally documented and designated as a hedge and the changes in their fair value must correlate with changes in the expected cash flow from anticipated future sales of production. Changes in the market value of these cash flow hedges are deferred through other comprehensive income ("OCI") until such time as the hedged volumes are produced and sold. Hedge effectiveness is measured at least quarterly based on relative changes in fair value between the derivative contract and the hedged item over time. Any ineffectiveness is immediately reported in other revenue in the Statements of Consolidated Operations. If the likelihood of occurrence of a hedged transaction ceases to be "probable", hedge accounting will cease on a prospective basis and all future changes in derivative fair value will be recognized currently in earnings. The net gain or loss from hedges terminated prior to maturity continue to be deferred until the hedged production is recognized in income. If it becomes probable that the hedged transaction will not occur, the derivative gain or loss associated with a terminated derivative will immediately be reclassified from OCI into earnings. If the contract is not designated as a hedge, changes in fair value are recorded currently in income.

See Note 9 for further discussion of the Company's price risk management activities.

Fair Value of Financial Instruments

The carrying value of certain financial instruments, including cash, cash equivalents, revolving credit debt and short-term debt approximates estimated fair value due to their short-term maturities and varying interest rates. The estimated fair value of public debt is based upon quoted market values. Derivative financial instruments are carried at fair value.

Property, Plant and Equipment

The Company follows the full cost method of accounting under which all costs incurred in acquisition, exploration and development activities are capitalized in a country-wide cost center. Such costs include lease acquisitions, geological and geophysical services, drilling, completion, equipment and certain salaries, benefits and other internal costs directly associated with acquisition, exploration and development activities. Interest costs related to unproved properties are also capitalized. Salaries, benefits and other internal costs related to production and general overhead are expensed as incurred. Effective January 1, 2002, the Company began providing for depreciation, depletion and amortization ("DD&A") of evaluated costs using the unit-of-production method based on recoverable reserves (including reserves associated with the Production Payment). See "New Accounting Principles". Future development costs and asset retirement obligations are added to the amortizable base. Costs directly associated with the acquisition and evaluation of unproved properties are excluded from the DD&A calculation until a complete evaluation is made and it is determined whether proved reserves can be assigned to the properties or if impairment has occurred. The costs of drilling exploratory dry holes are included in the amortization base immediately upon determination that such wells are dry. Geological and geophysical costs not associated with specific unevaluated properties are included in the amortization base as incurred. Costs of unevaluated properties excluded from amortization were $3.4 million and $8.5 million at December 31, 2002 and 2001, respectively. The Company will begin to amortize these costs when proved reserves are established or impairment is determined.

Capitalized costs of oil and gas properties, net of accumulated DD&A and related deferred taxes, are limited to the sum of the present value of estimated future net revenues from proved oil and gas reserves at current prices net of related tax effects discounted at 10%, plus the lower of cost or fair value of unproved properties. To the extent that the capitalized costs exceed this "ceiling" limitation at the end of any quarter, such excess is expensed.

During 2002, the Company sold certain non-core oil and gas properties for net proceeds of $30.5 million. Proceeds from dispositions of oil and gas properties are credited to the cost center with no recognition of gains or losses unless a significant portion of the Company's proved reserves are sold (generally more than 25%).

Depreciation of other property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets ranging from 3 to 20 years. Repairs of all property, plant and equipment and replacements and renewals of minor items of property are charged to expense as incurred.

Revenue Recognition

The Company follows the sales method of accounting for natural gas revenues whereby revenues are recognized based on volume sold. The volume of gas sold may differ from the volume to which KCS is entitled based on its working interest. An imbalance is recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under-produced owner(s) to recoup its entitled share through future production. The Company has a liability of $0.7 million for imbalances at December 31 for 2002 and

2001. Under the sales method, no receivables are recorded where KCS has taken less than its share of production. Gas imbalances are reflected as adjustments to proved gas reserves and future cash flows in the unaudited supplemental oil and gas disclosures.

Pursuant to the Production Payment discussed in Note 2, the Company recorded the net proceeds from the sale of this Production Payment of approximately $175 million as deferred revenue on the balance sheet. In accordance with SFAS No. 19 "Financial Accounting and Reporting by Oil and Gas Producing Companies," deliveries under this Production Payment are recorded as non-cash oil and gas revenue with a corresponding reduction of deferred revenue at the average price per Mcf of natural gas and per barrel of oil received when the Production Payment was sold. The Company also reflects the production volumes and depletion expense as deliveries are made. However, the associated oil and gas reserves are excluded from the Company's reserve data. In 2002, the Company delivered 11.2 Bcfe under this Production Payment and recorded $45.2 million of oil and gas revenue. Since the sale of the Production Payment in February 2001 through December 31, 2002, the Company has delivered 26.9 Bcfe, or 62% of the total quantity to be delivered. For 2003, scheduled deliveries are 6.8 Bcfe.

Stock Compensation

The cost of awards of restricted stock, determined as the market value of the shares at the date of grant, is expensed ratably over the restricted period. See Note 4.

As permitted under SFAS No. 123 "Accounting for Stock-Based Compensation", as amended, the Company has elected to continue to account for stock options under the provisions of Accounting Principles Board Opinion No. 25 "Accounting for Stock Issued to Employees." Under this method, the Company records no compensation expense for stock options granted if the exercise price of those options is equal to or greater than the market price of the Company's common stock on the date of grant, unless the awards are subsequently modified. The following table illustrates the effect on income (loss) available to common stockholders and earnings (loss) per share if the Company had applied the fair value recognition provision of SFAS No. 123, as amended.

	2002	2001	2000
	(amounts in thousands except per share data)		
Basic earnings (loss) per share			
Income (loss) available to common stockholders as reported	$(11,142)	$63,818	$41,523
Add: Stock-based compensation expense included in reported income available to common stockholders	782	1,419	—
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	(1,569)	1,316	(2,038)
Pro forma income (loss) available to common stockholders	$(11,929)	$66,553	$39,485
Average shares outstanding	35,834	31,668	29,266
Earnings (loss) per share:			
Basic — as reported	$ (0.31)	$ 2.02	$ 1.42
Basic — pro forma	$ (0.33)	$ 2.10	$ 1.35
Diluted earnings (loss) per share			
Income (loss) available to common stockholders as reported	$(11,142)	$63,818	$41,523
Dividends and accretion of issuance costs on preferred stock	n/a	1,761	—
Numerator as reported	(11,142)	65,579	41,523
Add: Stock-based compensation expense included in reported income available to common stockholders	782	1,419	—
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards	(1,569)	1,316	(2,038)
Pro forma numerator	$(11,929)	$68,314	$39,485
Average diluted shares outstanding	35,834	38,828	29,305
Earnings (loss) per share:			
Basic — as reported	$ (0.31)	$ 1.69	$ 1.42
Basic — pro forma	$ (0.33)	$ 1.76	$ 1.35

Allowance for Doubtful Accounts

The Company maintains an allowance for doubtful accounts receivable based upon the expected collectibility of all trade receivables. The allowance is reviewed continually and adjusted for accounts deemed uncollectible. The allowance was $4.7 million and $4.2 million at December 31, 2002 and 2001, respectively. Included in the allowance is $3.7 million which represents a 79% reserve against receivables from Enron entities in bankruptcy. The Company currently believes that the remaining $1.0 million receivable from such entities will ultimately be recovered based on several factors, including the Company's assessment that a large percentage of its Enron related receivables should qualify as priority claims in the bankruptcy process.

The Company extends credit, primarily in the form of monthly oil and gas sales and joint interest owners receivables, to various companies in the oil and gas industry, which may result in a concentration of credit risk. The concentration of credit risk may be affected by changes in economic or other conditions and may, accordingly, impact the Company's overall credit risk. However, the Company believes that the risk associated with these receivables is mitigated by the size and reputation of the companies to which the Company extends credit and by dispersion of credit risk among many parties.

Income Taxes

The Company accounts for income taxes in accordance with SFAS No. 109 "Accounting for Income Taxes." Deferred income taxes are recorded to reflect the future tax consequences of differences between the tax bases of assets and liabilities and their financial reporting amounts at each year end. A valuation allowance is recognized if at the time it is anticipated that some or all of a deferred tax asset may not be realized.

During the second quarter of 2002, the Company concluded that a $15.9 million increase in the valuation allowance, which reduced the carrying value of net deferred assets to zero, was appropriate. In making that assessment, management considered several factors, including future projections of taxable income, which reflected relatively low natural gas and oil prices at that time, and the January 2003 maturity of the Company's Senior Note obligations that required refinancing. While the Senior Note obligations have now been refinanced and natural gas and oil prices have improved significantly in recent months, the Company continues to maintain the valuation allowance against 100% of its net deferred tax assets. The Company made this determination since, at this time, it is difficult to project the necessary levels of future taxable income with sufficient certainty, considering the significant volatility in natural gas and oil prices and that the current higher price environment has existed for only a short period. The Company will continue to assess the valuation allowance and to the extent it is determined that such allowance is no longer required, the tax benefit of the remaining net deferred tax assets will be recognized in the future. See Note 8.

Earnings (Loss) Per Share

Basic earnings (loss) per share of common stock is computed by dividing income (loss) available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings (loss) per share of common stock reflects the potential dilution that could occur if the Company's dilutive outstanding stock options and warrants were exercised using the average common stock price for the period and if the Company's convertible preferred stock was converted to common stock.

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

	2002	2001	2000
	(Amounts in thousands except per share data)		
Basic earnings (loss) per share:			
Income (loss) available to common stockholders	$(11,142)	$63,818	$41,523
Average shares of common stock outstanding	35,834	31,668	29,266
Basic earnings (loss) per share	$ (0.31)	$ 2.02	$ 1.42
Diluted earnings (loss) per share:			
Income (loss) available to common stockholders	$(11,142)	$63,818	$41,523
Dividends and accretion of issuance costs on preferred stock	n/a	1,761	—
	$(11,142)	$65,579	$41,523
Average shares of common stock outstanding	35,834	31,668	29,266
Assumed conversion of convertible preferred stock	n/a	6,808	—
Dividends on convertible preferred stock	n/a	232	—
Stock options and warrants	n/a	120	39
	35,834	38,828	29,305
Diluted earnings (loss) per share	$ (0.31)	$ 1.69	$ 1.42

Common shares on assumed conversion of convertible preferred stock amounting to 4.8 million shares in 2002 were not included in the computation of diluted loss per common share nor were accrued dividends on convertible preferred stock or stock options and warrants since they would be anti-dilutive.

Common Stock Outstanding

	2002	2001	2000
Balance, beginning of year	34,677,399	29,265,910	29,268,310
Shares issued for:			
Option and benefit plans, net of forfeited shares	413,401	660,657	(2,400)
Conversion of redeemable preferred stock	980,664	4,589,990	—
Dividends on preferred stock paid in common stock	373,256	160,842	—
Balance, end of year	36,444,720	34,677,399	29,265,910

Segment Reporting

The Company operates in one reportable segment, as an independent oil and gas company engaged in the acquisition, exploration, exploitation and production of oil and gas properties. The Company's operations are conducted entirely in the United States.

New Accounting Principles

Effective January 1, 2002, KCS began amortizing the capitalized costs related to oil and gas properties on the unit-of-production basis ("UOP") using proved oil and gas reserves. Previously, KCS had computed amortization on the basis of future gross revenue ("FGR"). As discussed in "Revenue Recognition" above, the Company accounted for the proceeds from the Production Payment as deferred revenue and as such, did not credit the full cost pool for the proceeds. Accordingly, for purposes of calculating DD&A under both UOP and FGR, the Company includes reserves associated with the Production Payment. Under UOP, the amortization rate is computed by dividing the physical units of production by the physical units of proved reserves. Physical units of oil and gas are converted to a common unit of measurement on the basis of their relative energy content. Under FGR, the amortization rate is computed by dividing oil and gas revenue by the future gross revenue from proved reserves based on current prices. Using either the UOP or FGR, the amortization rate is applied to the amortizable base of the Company's oil and gas properties (the net book value of oil and gas properties less the cost of unevaluated oil and gas properties plus estimated future development costs associated with proved reserves, including estimated dismantlement and abandonment costs net of estimated salvage values).

The Company determined that the change to UOP was preferable under accounting principles generally accepted in the United States, since among other reasons, it provides a more rational basis for amortization during periods of volatile commodity prices and also increases consistency with others in the industry.

As a result of this change, the Company recorded a non-cash cumulative effect charge of $6.2 million, net of tax (or $0.17 per basic and diluted common share) in the Statements of Consolidated Operations. The effect of the change in accounting principle in 2002 was to decrease the net loss by approximately $3.2 million, or $0.09 per basic and diluted share. The following table illustrates the effect on income (loss) attributable to common stockholders and earnings per share if the Company had applied UOP to amortize its oil and gas properties during 2001 and 2000:

	2001	2000
	(Amounts in thousands except for per share data)	
Income attributed to common stock:		
As reported	$63,818	$41,523
Pro forma	64,655	38,281
Earnings per share		
Basic — as reported	$ 2.02	$ 1.42
Basic — pro forma	$ 2.04	$ 1.31
Diluted — as reported	$ 1.69	$ 1.42
Diluted — pro forma	$ 1.71	$ 1.31

In July 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 143, "Accounting for Asset Retirement Obligations". SFAS No. 143 requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the periods in which it is incurred. When the liability is initially recorded, the entity increases the carrying amount of the related long-lived asset. The liability is accreted to the fair value at the time of settlement over the useful life of the asset, and the capitalized cost is depreciated over the useful life of the related asset. The Company adopted SFAS No. 143 effective January 1, 2003. As a result, net property, plant and equipment was increased by $10.2 million, an asset retirement obligation of $11.1 million was recorded and a $0.9 million charge against net income will be reported in the first quarter of 2003 as a cumulative effect of a change in accounting principle.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS No. 144"). SFAS No. 144 addresses the financial accounting and reporting for the impairment or disposal of long-lived assets. SFAS No. 144 supersedes SFAS No. 121 but retains its fundamental provisions for the (a) recognition/measurement of impairment of long-lived assets to be held and used and (b) measurement of long-lived assets to be disposed of by sale. SFAS No. 144 also supersedes the accounting/reporting provisions of APB Opinion No. 30 for segments of a business to be disposed of but retains the requirement to report discontinued operations separately from continuing operations and extends that reporting to a component of an entity that either has been disposed of or is classified as held for sale. The Company adopted the provisions of SFAS No. 144 effective January 1, 2002, with no significant impact.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

2. Reorganization

On January 30, 2001, the United States Bankruptcy Court for the District of Delaware (the "Bankruptcy Court") confirmed the KCS Energy, Inc. plan of reorganization ("the Plan") under Chapter 11 of Title 11 of the United States Bankruptcy Code ("Bankruptcy Code") after the Company's creditors and stockholders voted to approve the Plan. On February 20, 2001, the Company completed the necessary steps for the Plan to go effective and emerged from bankruptcy having reduced its debt from a peak of $425.0 million in early 1999 to $215.0 million and having cash on hand in excess of $30 million.

Under the terms of the Plan, the Company: 1) sold a 43.1 Bcfe (38.3 Bcf of gas and 797,000 barrels of oil) production payment ("Production Payment") to be delivered in accordance with an agreed schedule over a five year period for net proceeds of approximately $175 million and repaid all amounts outstanding under its existing bank credit facilities, 2) sold $30.0 million of convertible preferred stock, 3) paid to the holders of the Company's 11% Senior Notes, on a pro rata basis, cash equal to the sum of (a) $60.0 million plus the amount of past due accrued and unpaid interest of $15.1 million on $60.0 million of the Senior Notes as of the effective date, compounded semi-annually at 11% per annum and (b) the amount of past due accrued and unpaid interest of $21.5 million on $90.0 million of the Senior Notes as of January 15, 2001, compounded semi-annually at 11% per annum, 4) paid to the holders of the Company's 8⅞% Senior Subordinated Notes, cash in the amount of past due accrued and unpaid interest of $23.7 million as of January 15, 2001, compounded semi-annually at 8⅞% per annum, 5) renewed the remaining outstanding $90.0 million principal amount of Senior Notes and $125.0 million principal amount of Senior Subordinated Notes under amended indentures but without a change in interest rates, and 6) paid pre-petition trade creditors in full. Shareholders retained 100% of their common stock, subject to dilution from conversion of the new convertible preferred stock.

3. Retirement Benefit Plan

The Company sponsors a Savings and Investment Plan ("Savings Plan") under Section 401(k) of the Internal Revenue Code. Eligible employees may contribute a portion of their compensation, as defined, to the Savings Plan, subject to certain IRS limitations. The Company may make matching contributions, which have been set by the Board of Directors at 50% of the employee's contribution (up to 6% of the employee's compensation, subject to certain regulatory limitations). The Savings Plan also contains a profit-sharing component whereby the Board of Directors may declare annual discretionary profit-sharing contributions. Profit-sharing contributions are allocated to eligible employees based upon their pro-rata share of total eligible compensation and may be made in cash or in KCS Common Stock. Contributions to the Savings Plan are invested at the direction of the employee in one or more funds or can be directed to purchase common stock of the Company at market value. The Company's matching contributions and discretionary profit-sharing contributions vest over a four-year employment period. Once the four-year employment period has been satisfied, all Company matching contributions and discretionary profit-sharing contributions vest immediately. Company contributions to the Savings Plan were $531,103 in 2002, $510,702 in 2001 and $454,341 in 2000. These amounts are included in general and administrative expense.

4. Stock Option and Incentive Plans

On February 20, 2001 in connection with the Plan (see Note 2), the Company's 1992 Stock Plan and the 1994 Directors' Stock Plan and all outstanding options thereunder were cancelled. Also, as part of the Plan, the KCS Energy, Inc. 2001 Employees and Directors Stock Plan ("2001 Stock Plan") was adopted. The 2001 Stock Plan provides that stock options, stock appreciation rights, restricted stock and bonus stock may be granted to employees of KCS. The 2001 Stock Plan provides that each non-employee director be granted stock options for 1,000 shares annually. This plan also provides that in lieu of cash, each non-employee director be issued KCS common stock with a fair market value equal to 50% of their annual retainer. The 2001 Stock Plan provides that the option price of shares issued be equal to the market price on the date of grant. Options granted to directors as part of their annual retainer vest immediately. All other options vest ratably on the anniversary of the date of grant over either two years or three years. All options expire 10 years after the date of grant. Options reissued to employees within six months of a cancellation are accounted for as a modification of the original award. For these awards, changes in the quoted market price of the Company's stock above the exercise price of the options result in a change in the measurement of compensation for the awards. No compensation expense was recorded for modified awards in 2002, 2001 or 2000. The 2001 Stock Plan provided for the issuance of up to 4,362,868 shares of KCS common stock.

Restricted shares awarded under the 2001 Stock Plan have a restriction period of three years during which ownership of the shares cannot be transferred and the shares are subject to forfeiture if employment terminates before the end of the restriction period. Certain restricted stock awards provide for the restriction period to accelerate to one year if certain performance criteria are met. Restricted stock is considered to be currently issued and outstanding and has the same rights as other common stock. The cost of the awards of restricted stock, determined as the market value of the shares at the date of grant, is expensed ratably over the restricted period. Restricted stock totaling 579,528 shares were outstanding at December 31, 2002.

At December 31, 2002, a total of 1,989,092 shares were available for future grants under the 2001 Stock Plan.

A summary of the status of the stock options under the 2001 Stock Plan, the cancelled 1992 Stock Plan and the cancelled 1994 Directors' Stock Plan at December 31, 2002, 2001 and 2000 and changes during the years then ended is presented below.

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used for grants in 2002: risk-free interest rate of 5.3%; expected dividend yield of 0.00%; expected life of 10 years; and expected stock price volatility of 86.7%. The weighted average assumptions used for grants in 2001 were: risk-free interest rate of 5.4%; expected dividend yield of 0.00%; and expected life of 10 years; and expected stock price volatility of 85.3%.

	2002		2001		2000	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	1,229,043	$5.49	1,378,430	$10.66	1,519,630	$ 9.98
Cancelled(a)	—	—	(1,225,930)	11.75	—	—
Granted	501,000	2.75	1,237,259	5.49	—	—
Exercised	—	—	(152,500)	1.86	—	—
Forfeited	(165,282)	4.42	(8,216)	5.51	(141,200)	3.40
Outstanding at end of year	1,564,761	4.73	1,229,043	5.49	1,378,430	10.66
Exercisable at end of year	494,522	$5.56	6,000	$ 9.61	1,019,580	$10.03
Weighted average fair value of options granted		$2.39		$ 4.52		$ —

(a) Cancelled in connection with the Company's plan of reorganization.

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

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at December 31, 2002	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at December 31, 2002	Weighted Average Exercise Price
$2.75 - $5.20	438,000	9.20	$2.75	6,000	$2.95
5.21 - 6.00	1,120,761	8.14	5.48	482,522	5.54
6.01 - 9.61	6,000	8.40	9.61	6,000	9.61
$2.75 - $9.61	1,564,761	8.44	$4.73	494,522	$5.56

The Company has an employee stock purchase program (the "Program") whereby all eligible employees and directors may purchase full shares from the Company at a price per share equal to 90% of the market value determined by the closing price on the date of purchase. The minimum purchase is 25 shares. The maximum annual purchase is the number of shares costing no more than 10% of the eligible employee's annual base salary, and for directors, 6,000 shares. The number of shares issued in connection with the Program was 8,209 shares, 9,160 shares and 100 shares during 2002, 2001 and 2000, respectively. At December 31, 2002, there were 775,989 shares available for issuance under the Program.

5. Debt

Debt consists of the following:

	2002	2001
	(Amounts in thousands)	
Credit Agreement	$ 500	$ —
11% Senior Notes	61,274	79,800
8⅞% Senior Subordinated Notes	125,000	125,000
	186,774	204,800
Classified as short-term debt	—	—
Long-term debt	$186,774	$204,800

Credit Agreement

On January 14, 2003, the Company amended and restated its credit agreement ("Credit Agreement") with a group of institutional lenders. The Credit Agreement, which matures on October 3, 2005, provides up to $90.0 million of borrowing capacity, $40.0 million in the form of a term loan, a $30.0 million revolving "A" facility and a $20.0 million revolving "B" facility. Borrowing capacity is subject to monthly borrowing base calculations with respect to the value of the Company's oil and gas assets. Initial proceeds of $69.3 million were used primarily to pay off the Company's maturing Senior Note obligations. The term loan and the revolving "B" facility, which may be prepaid at any time without penalty, bear interest based on the prime rate, initially equating to 9.0%, and increasing annually. The revolving "A" facility bears, at the Company's option, an interest rate of LIBOR plus 2.75% to 3.0% or prime plus 0.5% to 0.75%, depending on utilization. The revolving "A" facility requires a commitment fee of 0.5% per annum on the unused availability and carries an early termination penalty of 1.5% in the first year and 1% in the second year. Financing fees associated with the amended and restated agreement have been recorded as deferred charges and are being amortized as interest expense over the life of the Credit Agreement. The remaining deferred financing fees associated with the original agreement ($1.1 million) were written off to interest expense in December 2002.

Certain other fees are also payable under the Credit Facility based on services provided. Substantially all of the Company's assets are pledged to secure the Credit Agreement.

The Credit Agreement contains various restrictive covenants including ratios of debt to EBITDA, interest coverage, fixed charge coverage and liquidity. The Credit Agreement also contains provisions that require the hedging of a portion of the Company's oil and gas production, payment upon a change of control, restrictions on the payment of dividends and certain other restricted payments and places limitations on the incurrence of additional debt, capital expenditures, the sale of assets, and the repurchase of Senior Subordinated Notes. Any repayment made on the term loan portion of the facility will permanently reduce the funds available under the Credit Agreement. The Credit Agreement also contains cross-default provisions which would result in the acceleration of payments if the Company defaults on its other debt instruments.

Senior Notes

On January 25, 1996, KCS issued $150.0 million principal amount of 11% Senior Notes due 2003 (the "Senior Notes"). The Company redeemed $70.2 million of Senior Notes in 2001, $18.5 million in 2002 and paid off the remaining $61.3 million upon maturity on January 15, 2003. The balance at December 31, 2002 has been classified as long-term because of the Company's intent and ability to refinance such amounts on a long-term basis through the Credit Agreement amended on January 14, 2003.

Senior Subordinated Notes

On January 15, 1998, the Company completed a public offering of $125.0 million of Senior Subordinated Notes at an interest rate of 8⅞%. The Senior Subordinated Notes were non-callable for five years and are unsecured subordinated obligations of KCS. The subsidiaries of KCS have guaranteed the Senior Subordinated Notes on an unsecured subordinated basis. The guarantees are full and unconditional and joint and several.

On February 20, 2001, in connection with the Plan (see Note 2), the indenture governing the Senior Subordinated Notes was amended to, among other things, accelerate the maturity date of the Senior Subordinated Notes from January 15, 2008 to January 15, 2006.

The Senior Subordinated Notes, as amended, contain certain restrictive covenants which, among other things, limit the Company's ability to incur additional indebtedness, require the repurchase of the Senior Subordinated Notes upon a change of control, and limit: a) the aggregate purchases and redemptions of the Company's Series A Convertible Preferred Stock for cash and b) the aggregate cash dividends paid on capital stock, collectively, to 50% of the Company's cumulative net income, as defined, during the period beginning after December 31, 2000. The Senior Subordinated Notes also contain cross-default provisions which would result in the acceleration of payments if the Company defaults on its other debt instruments.

Other Information

The estimated fair values of the Company's Senior Notes and Senior Subordinated Notes are based on quoted market values and at December 31, 2002 were $61.3 million and $94.4 million, respectively. The estimated fair value of the Company's Senior Notes and Senior Subordinated Notes at December 31, 2001 were $79.4 million and $85.0 million, respectively.

The scheduled maturities of the Company's debt during the next five years are as follows: $-0- in 2003, $-0- in 2004, $61.8 million in 2005 and $125.0 million in 2006.

Total interest payments were $19.2 million in 2002, $71.5 million in 2001 and $8.6 million in 2000. Interest payments in 2001 included approximately $60.7 million made in connection with the Plan (see Note 2). The 2001 payments include $60.3 million paid in connection with the Plan to holders of the Senior

Notes and the Senior Subordinated Notes for interest accrued but not paid during the reorganization period, which included interest on interest. Capitalized interest was $0.7 million in 2002, $0.6 million in 2001 and $0.6 million in 2000.

6. Redeemable Convertible Preferred Stock

In connection with the Plan (see Note 2), the Company issued 30,000 shares of Series A Convertible Preferred Stock, $0.01 par value ("Preferred Stock") at a price of $1,000 per share convertible at any time into a total of 10,000,000 shares of KCS Common Stock at a conversion price of $3.00 per share. Net proceeds from the issuance of the Preferred Stock was $28.4 million. The excess of the redemption value of the Preferred Stock over the original net issuance proceeds is reflected as accretion of issuance costs on preferred stock in the Statements of Consolidated Operations. The Preferred Stock pays a 5% per annum dividend payable quarterly in cash or, during the first two years following issuance, in shares of KCS common stock valued at the average of the high and the low trading price for the twenty trading days prior to the dividend payment date. The Preferred Stock is redeemable at the option of the Company if the closing price of the Common Stock exceeds $6.00 per share for 25 out of 30 consecutive trading days or at the election of holders of a majority of the outstanding shares of Preferred Stock on or after January 31, 2009.

In connection with the issuance of the Preferred Stock, the Company issued the placement agent warrants, which expire on February 29, 2006, to purchase 400,000 shares of KCS common stock at $4.00 per share.

The Preferred Stock has no voting rights except upon certain defaults or failure to pay dividends and as otherwise required by law. The Preferred Stock ranks senior to Common Stock or any future issue of preferred stock. The Preferred Stock has a liquidation preference of $1,000 per share plus accrued and unpaid dividends.

As a result of conversions of the Preferred Stock, 1.0 million and 4.6 million shares of common stock were issued in 2002 and 2001, respectively. In addition 0.4 million and 0.2 million shares of common stock were issued as dividends on the preferred stock in 2002 and 2001, respectively. In January 2003, 1.2 million shares of common stock were issued as a result of conversions of the Preferred Stock.

7. Leases and Unconditional Purchase Obligations

Future minimum lease payments under operating leases having initial or remaining non-cancelable lease terms in excess of one year are as follows: $1.5 million in 2003, $1.2 million in 2004, $0.5 million in 2005, $0.3 million in 2006 and none thereafter. Lease payments charged to operating expenses amounted to $1.3 million, $0.8 million and $0.6 million during 2002, 2001 and 2000, respectively. In addition, the Company has unconditional purchase obligations, primarily related to natural gas transportation contracts of $2.9 million in 2003, $2.9 million in 2004, $2.6 million in 2005 and $0.7 million in 2006.

8. Income Taxes

Federal and state income tax provision (benefit) includes the following components:

	For the Year Ended December 31,		
	2002	2001	2000
	(Dollars in thousands)		
Current provision (benefit)	$ —	$ —	$ —
Deferred provision (benefit), net	12,937	(8,359)	—
Federal income tax provision (benefit)	12,937	(8,359)	—
State income tax provision (deferred provision $826 in 2002, deferred benefit $600 in 2001)	826	—	—
	$13,763	$ (8,359)	$ —
Reconciliation of federal income tax expense (benefit) at statutory rate to provision for income taxes:			
Income before income taxes	$ 9,815	$ 57,220	$ 41,523
Tax provision at 35% statutory rate	3,435	20,027	14,533
Change in valuation allowance	9,776	(28,401)	(14,544)
State income taxes, net of federal benefit	537	—	—
Other, net	15	15	11
	$13,763	$ (8,359)	$ —

The primary differences giving rise to the Company's net deferred tax assets are as follows:

	December 31,	
	2002	2001
	(Dollars in thousands)	
Income tax effects of:		
Deferred tax assets		
Alternative minimum tax credit carry forwards	$ 2,776	$ 378
Net operating loss carry forward	75,377	78,078
Statutory depletion carryforward	400	400
Other	3,346	1,449
Gross deferred tax asset	81,899	80,305
Valuation allowance	(74,439)	(62,506)
Deferred tax assets	7,460	17,799
Deferred tax liabilities		
Property related items	(5,565)	(1,879)
Deferred revenue	(1,895)	—
Deferred tax liabilities	(7,460)	(1,879)
Net deferred tax asset	$ —	$ 15,920

State income tax payments were $0.5 million in 2002 and $0.1 million in 2001. No income tax payments were made in 2000.

Due to the significant losses recorded in 1998 and the uncertainty of future oil and natural gas commodity prices, the Company concluded at that time that a valuation allowance against net deferred tax assets was required in accordance with SFAS No. 109. In making its assessment, the Company considered several factors, including uncertainty of the Company's ability to generate sufficient income in order to realize its future tax benefits. A substantial portion of the valuation allowances provided by the Company relates to loss and credit carryforwards. To determine the proper amount of valuation allowances with respect to these carryforwards, the Company evaluated all appropriate factors, including any limitations concerning their use resulting from consequences of its bankruptcy or otherwise and the year the carryforwards expire, as well as the levels of taxable income necessary for utilization.

During the second quarter of 2002, the Company concluded that a $15.9 million increase in the valuation allowance, which reduced the carrying value of net deferred assets to zero, was appropriate. In making that assessment, management considered several factors, including future projections of taxable income, which reflected relatively low natural gas and oil prices at that time, and the January 2003 maturity of the Company's Senior Note obligations that required refinancing. While the Senior Note obligations have now been refinanced and natural gas and oil prices have improved significantly in recent months, the Company continues to maintain the valuation allowance against 100% of its net deferred tax assets. The Company made this determination, since at this time, it is difficult to project the necessary levels of future taxable income with sufficient certainty, considering the significant volatility in natural gas and oil prices and that the current higher price environment has existed for only a short period. The Company will continue to assess the valuation allowance and to the extent it is determined that such allowance is no longer required, the tax benefit of the remaining net deferred tax assets will be recognized in the future.

At December 31, 2002, the Company had tax net operating losses (NOLs) of approximately $215.4 million available to offset future taxable income, of which approximately $59.2 million will expire in 2012, $73.8 million will expire in 2018, $34.1 million will expire in 2019, $26.0 million will expire in 2020 and $22.3 million will expire in 2022.

9. Derivatives

Oil and gas prices have historically been volatile. The Company has at times utilized derivative contracts, including swaps, futures contracts, options and collars, to manage this price risk.

Commodity Price Swaps. Commodity price swap agreements require the Company to make or receive payments from the counter parties based upon the differential between a specified fixed price and a price related to those quoted on the New York Mercantile Exchange for the period involved.

Futures Contracts. Oil or natural gas futures contracts require the Company to sell and the counter party to buy oil or natural gas at a future time at a fixed price.

Option Contracts. Option contracts provide the right, not the obligation, to buy or sell a commodity at a fixed price. By buying a "put" option, the Company is able to set a floor price for a specified quantity of its oil or gas production. By selling a "call" option, the Company receives an upfront premium from selling the right for a counter party to buy a specified quantity of oil or gas production at a fixed price.

Price Collars. Selling a call option and buying a put option creates a "collar" whereby the Company establishes a floor and ceiling price for a specified quantity of future production. Buying a call option with a strike price above the sold call strike price establishes a "3-way collar" that entitles the Company to capture the benefit of price increases above that call price.

Upon adoption of SFAS No. 133, the Company recorded a liability of $43.8 million representing the fair market value of its derivative instruments at adoption, a related deferred tax asset of $15.3 million and an after-tax cumulative effect of change in accounting principle of $28.5 million to accumulated OCI. The Company elected not to designate its then existing derivative instruments as hedges which, subsequent to adoption of SFAS No. 133, would require that changes in a derivative instrument's fair value be recognized currently in earnings. However, SFAS No. 133 requires the Company's derivative instruments that had been designated as cash flow hedges under accounting principles generally accepted prior to the initial application of SFAS No. 133 to continue to be accounted for as cash flow hedges with the transition adjustment reported as a cumulative-effect-type adjustment to accumulated OCI as mentioned above.

In February 2001, the Company terminated certain derivative instruments in connection with its emergence from bankruptcy for a cash payment of $28.0 million, which was offset against the accrued liability recorded in connection with the adoption of SFAS No. 133. During the quarter ended March 31, 2001, as a result of market price decreases, the ultimate cost to settle the remaining derivative instruments in place at January 1, 2001 was reduced by $7.7 million. This non-cash gain was recorded in other revenue during the quarter. The actual cost to settle the remaining derivatives was $8.1 million. During 2001, $15.5 million, net of tax, of the above $28.5 million charged to OCI was reclassified into earnings. The $8.5 million remaining in accumulated other comprehensive income will be amortized into earnings over the original term of the derivative instruments, which extends through August 2005 ($3.6 million in 2003, $2.9 million in 2004 and $2.0 million in 2005).

During 2001, all derivative contracts, other than the derivatives terminated in connection with emergence from bankruptcy as discussed above, were with Enron North America Corp., a subsidiary of Enron Corp. At the end of November 2001, the Company had price swap contracts, designated as hedges, covering 0.3 million MMbtu of December 2001 gas production; and price swaps and collars covering 6.2 million MMBtu of 2002 gas production. The recorded value of these derivatives at that time was estimated to be $2.7 million. Because of Enron's financial condition, the Company concluded that these derivative contracts no longer qualified for hedge accounting treatment. The Company unwound the December derivatives and certain swap contracts covering 1.0 million MMbtu of 2002 gas production. In December 2001, Enron North America Corp. and Enron Corp. filed for bankruptcy protection and did not pay the Company for the contracts that were unwound. At December 31, 2001, $2.3 million in unrealized gains related to 2002 gas production was included in accumulated OCI and was reclassified into earnings during 2002. The related assets were reclassified as a receivable from Enron and a provision for doubtful accounts was established.

At December 31, 2002, the Company had no derivative contracts outstanding. The Company realized $4.9 million in net hedging losses during 2002, including $5.0 million net hedging losses due to reclassifications from OCI for contracts terminated prior to January 1, 2002. At December 31, 2001, the Company was not a party to derivative contracts other than the Enron contracts described above. The Company realized $22.1 million in net hedging losses and $8.6 million net non-hedge derivative losses during 2001.

The table below presents changes in OCI associated with the Company's derivative transactions since adopting SFAS No. 133.

	2002	2001
	(Amounts in thousands)	
Balance, beginning of year	$(11,162)	$ —
Cumulative effect of accounting change	—	(28,451)
Reclassification adjustments of derivatives, net of tax	2,812	15,524
Changes in fair value of hedging positions	(144)	1,894
Ineffective portion of hedges	(7)	(129)
Balance, end of year	$ (8,501)	$(11,162)

The unrealized loss balances at the end of year on the Company's derivative transactions are net of income tax benefit of $4.6 million and $7.0 million for 2002 and 2001, respectively.

During February 2003, the Company entered into a series of derivative transactions designed to protect against possible declines in natural gas prices while enabling the Company to benefit from price increases. These transactions, which covered 3.5 million MMbtu of 2003 gas production, as summarized below:

	Expected Maturity, 2003				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Swaps:					
Volumes (bbl)	30,000	15,000	—	—	45,000
Weighted average price ($/bbl)	$ 31.06	$ 31.06	$ —	$ —	$ 31.06
Puts/Floors:					
Volumes (MMbtu)	—	150,000	460,000	305,000	915,000
Weighted average price ($/MMbtu)	$ —	$ 4.25	$ 4.25	$ 4.25	$ 4.25
3-way collars:					
Volumes (MMbtu)	—	1,060,000	1,075,000	460,000	2,595,000
Weighted average price ($/MMbtu)					
Floor (purchased put option)	$ —	$ 4.83	$ 4.47	$ 4.40	$ 4.61
Cap 1 (sold call option)	$ —	$ 5.81	$ 5.76	$ 5.75	$ 5.78
Cap 2 (purchased call option)	$ —	$ 6.31	$ 6.26	$ 6.25	$ 6.28

10. Litigation

Environmental Suits

The Company was a defendant in a lawsuit originally brought by InterCoast Energy Company and MidAmerican Capital Company ("Plaintiffs") against KCS Energy, Inc., KCS Medallion Resources, Inc. and Medallion California Properties Company ("KCS Defendants"), and Kerr-McGee Oil & Gas Onshore LP and Kerr-McGee Corporation ("Kerr-McGee Defendants") in the 234th Judicial District Court of Harris County, Texas under Cause Number 1999-45998. The suit sought a declaratory judgment declaring the rights and obligations of each of the Plaintiffs, the KCS Defendants and the Kerr-McGee Defendants in connection with environmental damages and surface restoration on lands located in Los Angeles County, California which are covered by an Oil & Gas Lease dated June 13, 1935, from Newhall Land and Farming Company, as Lessor, to Barnsdall Oil Company, as Lessee (the "RSF Lease") and by an Oil and Gas Lease dated June 6, 1941, from the Newhall Corporation, as Lessor, to C. G. Willis, as Lessee (the "Ferguson Lease" and together with the RSF Lease, the "Leases").

The Kerr-McGee Defendants, KCS Defendants and Plaintiffs entered into an Agreed Interlocutory Judgment that contains clarification of the language of the 1990 agreement between predecessors of the KCS Defendants and the Kerr-McGee Defendants (the "1990 Agreement") under which the Leases were transferred from Kerr-McGee's predecessor to predecessors of Medallion California Properties Company ("MCPC"). The Court previously entered the Agreed Interlocutory Judgment, which essentially disposed of interpretation questions concerning the 1990 Agreement. After entry of the Agreed Interlocutory Judgment, the remaining issues in the case concerned the interpretation of the 1996 Stock Purchase Agreement through which certain of the KCS Defendants acquired the stock of MCPC. Specifically, the remaining issues involved the extent to which Plaintiffs are obligated to indemnify the KCS Defendants for environmental investigation costs previously incurred by the KCS Defendants and also for costs of defense and liability to the KCS Defendants, if any, in the California litigation described below. By Compromise and Settlement Agreement dated as of October 19, 2001, the Plaintiffs and KCS Defendants agreed: (i) to settle those issues dealing with the Plaintiffs' obligations to reimburse costs previously incurred in connection with defense of the California case described below; (ii) to provide prospectively for the control of defense and settlement and the sharing of defense costs in the California case described below; and (iii) to defer any disputes concerning the respective liability of Plaintiffs and KCS Defendants for any individual claims until the extent of such individual claim liability, after giving effect to indemnification obligations under the 1990 Agreement, is fully and finally determined. The Agreed Interlocutory Judgment has now been entered as a final judgment.

MCPC is a defendant in a lawsuit filed January 30, 2001, by The Newhall Land and Farming Company ("Newhall") against MCPC and Kerr-McGee Corporation and several Kerr-McGee affiliates. The case is currently pending in Los Angeles County Superior Court under Cause Number BC244203. In the suit, Newhall seeks damages for alleged environmental contamination and surface restoration on the lands covered by the RSF Lease and also seeks a declaration that Newhall may terminate the RSF Lease or alternatively, that it may terminate those portions of the RSF Lease on which there is currently default under the Lease. MCPC claims that Newhall is not entitled to lease termination as a remedy and that Kerr-McGee and InterCoast and MidAmerican owe indemnities to MCPC for defense and certain potential liability under Newhall's action, all as more particularly described in the Harris County, Texas litigation described above. Discovery is ongoing, and the lawsuit is set for trial in May 2003.

Other

The Company and several of its subsidiaries have been named as co-defendants along with numerous other industry parties in an action brought by Jack Grynberg on behalf of the Government of the United States. The complaint, filed under the Federal False Claims Act, alleges underpayment of royalties to the Government of the United States as a result of alleged mismeasurement of the volume and wrongful analysis of the heating content of natural gas produced from federal and Native American lands. The complaint is substantially similar to other complaints filed by Jack Grynberg on behalf of the Government of the United States against multiple other industry parties. All of the complaints have been consolidated in one proceeding. In April 1999, the Government of the United States filed notice that it had decided not to intervene in these actions. The Company believes that the allegations in the complaint are without merit.

The Company is also a party to various other lawsuits and governmental proceedings, all arising in the ordinary course of business. Although the outcome of all of the above proceedings cannot be predicted with certainty, management does not expect such matters to have a material adverse effect, either singly or in the aggregate, on the financial position or results of operations of the Company. It is possible, however, that charges could be required that would be significant to the operating results during a particular period.

11. Quarterly Financial Data (unaudited)

	Quarters			
	First	Second	Third	Fourth
	(Dollars in thousands, except per share data)			
2002				
Revenue	$28,824	$ 30,277	$30,472	$29,246
Operating income	5,422	7,784	7,830	8,445
Net income (loss)	$(4,908)	$(12,368)	$ 3,813	$ 3,349
Basic earnings (loss) per common share	$ (0.14)	$ (0.35)	$ 0.11	$ 0.09
Diluted earnings (loss) per common share	$ (0.14)	$ (0.35)	$ 0.09	$ 0.08

	Quarters			
	First	Second	Third	Fourth
2001				
Revenue	$72,709	$49,038	$39,466	$30,778
Operating income	44,097	22,941	13,334	276
Net income (loss)	$40,980	$19,228	$ 8,999	$(3,628)
Basic earnings (loss) per common share	$ 1.38	$ 0.63	$ 0.27	$ (0.11)
Diluted earnings (loss) per common share	$ 1.21	$ 0.48	$ 0.22	$ (0.11)

Effective January 1, 2002, the Company changed its method of amortizing its oil and gas properties from FGR to UOP. See Note 1 to Consolidated Financial Statements. The previously reported amounts reflected in quarterly reports on Form 10-Q for the first three quarters of 2002 reflected FGR. These amounts have been recalculated to reflect UOP in the table above. The effect of this change was to decrease the net losses in the first and second quarters by $2.1 million and $0.8 million, respectively, and increase net income by $0.2 million in both the third and fourth quarters. Amounts for 2001 have not been restated to reflect the change.

The total of the earnings per share for the quarters may not equal the earnings per share elsewhere in the Consolidated Financial Statements as each quarterly computation is based on the weighted average number of common shares outstanding during that period. In addition, certain potentially dilutive securities were not included in certain of the quarterly computations of diluted earnings (loss) per common share because to do so would have been anti-dilutive.

12. Oil and Gas Producing Operations (Unaudited)

The following data is presented pursuant to SFAS No. 69 "Disclosure about Oil and Gas Producing Activities" with respect to oil and gas acquisition, exploration, development and producing activities, which is based on estimates of year-end oil and gas reserve quantities and forecasts of future development costs and production schedules. These estimates and forecasts are inherently imprecise and subject to substantial revision as a result of changes in estimates of remaining volumes, prices, costs and production rates.

Except where otherwise provided by contractual agreement, future cash inflows are estimated using year-end prices. Oil and gas prices at December 31, 2002 are not necessarily reflective of the prices the Company expects to receive in the future. Other than gas sold under contractual arrangements, gas prices were based on year-end spot market prices of $4.74, $2.65 and $9.53 per MMBTU adjusted by lease for BTU content, transportation fees and regional price differentials at December 31, 2002, 2001 and 2000, respectively. Oil prices were based on West Texas Intermediate (WTI) posted prices of $28.00, $16.75 and $23.75 at

December 31, 2002, 2001 and 2000, respectively adjusted by lease for gravity, transportation fees and regional price differentials.

Purchased VPP volumes represent oil and gas reserves acquired from third parties which generally entitle the Company to a specified volume of oil and gas to be delivered over a stated time period. The related volumes stated herein reflect scheduled amounts of oil and gas to be delivered to the Company at agreed delivery points and future cash inflows are estimated at year-end prices. Although specific terms of the Company's VPPs vary, the Company is generally entitled to receive delivery of its scheduled oil and gas volumes, free of drilling and lease operating costs. The Company received the final deliveries under purchased VPP's in December 2002. Therefore, reserve data as of December 31, 2002 do not include any VPP volumes.

Reserves at December 31, 2002 and 2001 have been reduced to reflect the sale of the Production Payment of 38.3 Bcf of gas and 797,000 barrels of oil as discussed in Note 2.

Production Revenues and Costs (unaudited)

Information with respect to production revenues and costs related to oil and gas producing activities is as follows:

	For the Year Ended December 31,		
	2002	2001	2000
	(Dollars in thousands)		
Revenue(a)	$ 120,002	$ 174,434	$ 190,511
Production (lifting) costs and taxes	30,835	38,651	34,406
Technical support and other	3,198	5,049	4,601
Depreciation, depletion and amortization	49,120	58,172	50,316
Total expenses	83,153	101,872	89,323
Pretax income from producing activities	36,849	72,562	101,188
Income tax expense (benefit)	13,763	(8,359)	—
Results of oil and gas producing activities (excluding corporate overhead and interest)	$ 23,086	$ 80,921	$ 101,188
Depreciation, depletion and amortization rate per Mcfe	$ 1.31	$ 1.25	$ 1.00
Capitalized costs incurred:			
Property acquisition	$ 4,822	$ 26,770	$ 7,264
Exploration	12,428	15,321	19,302
Development	30,314	42,942	36,032
Total capitalized costs incurred	$ 47,564	$ 85,033	$ 62,598
Capitalized costs at year end:			
Proved properties	$1,119,339	$1,097,143	$1,020,099
Unproved properties	3,364	8,470	5,582
	1,122,703	1,105,613	1,025,681
Less accumulated depreciation, depletion and amortization	(891,124)	(837,096)	(780,512)
Net investment in oil and gas properties	$ 231,579	$ 268,517	$ 245,169

(a) Includes amortization of deferred revenue of $45,182 in 2002, and $63,089 in 2001 related to volumes delivered under the Production Payment sold in February 2001. See Note 2.

Discounted Future Net Cash Flows (Unaudited)

The following information relating to discounted future net cash flows has been prepared on the basis of the Company's estimated net proved oil and gas reserves in accordance with SFAS No. 69.

Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	December 31,		
	2002	2001	2000
	(Dollars in thousands)		
Future cash inflows	$ 908,031	$ 631,061	$2,234,831
Future costs:			
Production	(279,282)	(228,701)	(451,763)
Development	(58,253)	(64,251)	(54,568)
Future income taxes	(49,203)	—	(428,644)
Future net revenues	521,293	338,109	1,299,856
Discount — 10%	(199,077)	(135,921)	(447,248)
Standardized measure of discounted future net cash flows	$ 322,216	$ 202,188	$ 852,608

Changes in Discounted Future Net Cash Flows from Proved Reserve Quantities

	For the Year Ended December 31,		
	2002	2001	2000
	(Dollars in thousands)		
Balance, beginning of year	$202,188	$ 852,608	$ 292,790
Increases (decreases)			
Sales, net of production costs	(48,878)	(72,694)	(156,105)
Net change in prices, net of production costs	135,290	(660,420)	729,127
Discoveries and extensions, net of future production and development costs	66,487	37,865	153,415
Changes in estimated future development costs	13,636	7,046	(9,953)
Change due to acquisition of reserves in place	11,945	27,591	34,087
Development costs incurred during the period	6,868	10,689	19,302
Revisions of quantity estimates	(38,541)	(14,433)	(12,720)
Accretion of discount	20,219	85,261	29,279
Net change in income taxes	(21,306)	251,871	(251,871)
Sales of reserves in place	(24,842)	(341,223)	(344)
Changes in production rates (timing) and other	(850)	18,027	25,601
Net increase (decrease)	120,028	(650,420)	559,818
Balance, end of year(a)	$322,216	$ 202,188	$ 852,608

(a) Excludes $66,582 and $111,880 of deferred revenue at December 31, 2002 and 2001, respectively, related to the Production Payment sold in 2001 as discussed in Note 2.

Reserve Information (Unaudited)

The reserve estimates and associated cash flows for all properties for the years ended December 31, 2002 and 2000 were prepared by Netherland, Sewell & Associates, Inc. ("NSA"). For the year ended December 31, 2001, the reserve estimates were prepared by the Company and audited by NSA. Proved developed reserves represent only those reserves expected to be recovered through existing wells using equipment currently in place. Proved undeveloped reserves represent proved reserves expected to be recovered from new wells or from existing wells after material recompletion expenditures. All of the Company's reserves are located within the United States.

	2002		2001		2000	
	Gas MMcf	Oil Mbbl	Gas MMcf	Oil Mbbl	Gas MMcf	Oil Mbbl
Proved developed and undeveloped reserves						
Balance, beginning of year	190,141	6,644	211,628	8,986	227,119	8,341
Production(a)	(19,733)	(1,082)	(23,133)	(1,273)	(41,089)	(1,570)
Discoveries, extensions, etc.	25,777	1,043	35,250	725	25,715	1,303
Acquisition of reserves in place	6,253	161	18,382	140	5,921	293
Sales of reserves in place(b)	(21,406)	(879)	(41,759)	(1,064)	(213)	(40)
Revisions of estimates	(26,039)	885	(10,227)	(870)	(5,825)	659
Balance, end of year	154,993	6,772	190,141	6,644	211,628	8,986
Proved developed reserves						
Balance, beginning of year	139,137	5,915	173,995	7,885	175,896	7,568
Balance, end of year	124,451	5,653	139,137	5,915	173,995	7,885

(a) 2001 and 2002 production excludes volumes produced and delivered with respect to the Production Payment sold in February 2001 as discussed in Note 2.

(b) The Company sold a Production Payment in 2001 as discussed in Note 2. The approximate 38.3 Bcf of gas and 797,000 barrels of oil Production Payment is reflected as sales of reserves in place in 2001 in the table above.

Item 9. ***Changes in and Disagreements with Accountants or Accounting and Financial Disclosure***

By unanimous written consent dated July 1, 2002, the Company's board of directors, upon the recommendation of its Audit Committee, approved the dismissal of Arthur Andersen LLP ("Andersen") and the appointment of Ernst & Young LLP to serve as the Registrant's independent public accountants for the fiscal year ending December 31, 2002.

The audit reports of Andersen with respect to the consolidated financial statements of the Company as of and for the fiscal years ended December 31, 2001 and December 31, 2000 did not contain any adverse opinion or disclaimer of opinion, nor were they qualified or modified as to uncertainty or audit scope. In addition, there were no modifications as to accounting principles except that the most recent audit report of Andersen dated March 13, 2002 contained an explanatory paragraph with respect to the change in the method of accounting for derivative instruments effective January 1, 2001 as required by the Financial Accounting Standards Board.

During the years ended December 31, 2001 and 2000 and the subsequent interim period through July 1, 2002, there were no disagreements with Andersen on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure which, if not resolved to Andersen's satisfaction, would have caused them to make reference to the subject matter in connection with their report on the Company's financial statements for such years, and there were no reportable events as defined in Item 304(a)(1)(v) of Regulation S-K.

The Company provided Andersen with a copy of the above disclosures and requested that Andersen furnish the Company with a letter addressed to the Securities and Exchange Commission stating whether or not Andersen agreed with the statements made by the Company and, if not, stating the respects in which it does not agree. The Company was informed by Andersen's national office that Andersen could not issue such a letter due to the discontinuance of its audit practice.

During the Company's two fiscal years ended December 31, 2001 and 2000, and the subsequent interim period through July 1, 2002, the Company did not consult Ernst & Young LLP with respect to the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on the Company's consolidated financial statements, or any other matters or reportable events described in Items 304(a)(2)(i) and (ii) of Regulation S-K.

PART III

Item 10. ***Directors and Executive Officers of the Registrant***

Information for this item is set forth in our Proxy Statement for the 2003 Annual Meeting of Stockholders, and is incorporated herein by reference.

Item 11. ***Executive Compensation***

Information for this item is set forth in our Proxy Statement for the 2003 Annual Meeting of Stockholders, and is incorporated herein by reference.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

Information for this item is set forth in our Proxy Statement for the 2003 Annual Meeting of Stockholders, and is incorporated herein by reference. Information concerning securities authorized for issuance under equity compensation plans is set forth in Item 5 of this Form 10-K and is incorporated herein by reference.

Item 13. ***Certain Relationships and Related Transactions***

Information for this item is set forth in our Proxy Statement for the 2003 Annual Meeting of Stockholders, and is incorporated herein by reference.

Item 14. *Controls and Procedures*

(a) Evaluation of disclosure controls and procedures

The term disclosure controls and procedures is defined in Rules 13a-14(c) and 15d-14(c) of the Securities Exchange Act of 1934. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Furthermore, we have designed our disclosure controls and procedures to ensure that information that we are required to disclose in our report is accumulated and communicated to management (including our Chief Executive Officer and Principal Financial Officer) in a manner that permits timely decisions to be made regarding required disclosure.

Our Chief Executive Officer and our Principal Financial Officer have evaluated the effectiveness of our disclosure controls and procedures as of a date within 90 days prior to the date of the filing of this annual report, and they have concluded that such disclosure controls and procedures were effective at ensuring that they were alerted in a timely manner as to all material information that we are required to include in our reports with the Securities and Exchange Commission.

(b) Changes in internal controls

We maintain a system of internal accounting controls that is designed to provide reasonable assurance that our books and records accurately reflect our transactions and that our established policies and procedures are followed. Since the date of the evaluation of our disclosure controls and procedures by our Chief Executive Officer and Principal Financial Officer, there have been no significant changes to our internal controls or in other factors that could significantly affect our internal controls subsequent to the date of the most recent evaluation.

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

(a) *Financial statements, financial statement schedules and exhibits*

(1) The following consolidated financial statements of KCS and its subsidiaries and the related Report of Independent Public Accountants are presented in Item 8 of this Form 10-K.

(2) *Financial Statement Schedules*

Financial statement schedules have been omitted because they are either not required, not applicable or the information required to be presented is included in the Company's financial statements and related notes.

(3) *Exhibits*

See "Exhibit Index" located on page 61 of this Form 10-K for a listing of all exhibits filed herein or incorporated by reference to a previously filed registration statement or report with the Securities and Exchange Commission ("SEC").

(b) *Reports on Form 8-K*

On December 18, 2002, the Company filed a report on Form 8-K under Item 5, Other Events reporting the extension of the maturity date on its bank credit facility. There were no other reports on Form 8-K filed during the three months ended December 31, 2002. On January 21, 2003, the Company filed a report on Form 8-K under Item 5, Other Events reporting that the Company had completed its previously announced financing and that it paid off the balance of its maturing Senior Notes obligations.

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.

KCS ENERGY, INC.

By: /s/ FREDERICK DWYER

Frederick Dwyer
Vice President, Controller and Secretary

Date: March 27, 2003

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 on the dates indicated.

Name	Title	Date
/s/ JAMES W. CHRISTMAS James W. Christmas	President, Chief Executive Officer and Director (Principal Executive Officer)	March 27, 2003
/s/ G. STANTON GEARY G. Stanton Geary	Director	March 27, 2003
/s/ JAMES E. MURPHY James E. Murphy	Director	March 27, 2003
/s/ ROBERT G. RAYNOLDS Robert G. Raynolds	Director	March 27, 2003
/s/ JOEL D. SIEGEL Joel D. Siegel	Director	March 27, 2003
/s/ CHRISTOPHER A. VIGGIANO Christopher A. Viggiano	Director	March 27, 2003
/s/ FREDERICK DWYER Frederick Dwyer	Vice President, Controller and Secretary (Principal Financial Officer and Principal Accounting Officer)	March 27, 2003

CERTIFICATIONS

I, James W. Christmas, certify that:

1. I have reviewed this annual report on Form 10-K of KCS Energy, Inc.;

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

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

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

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

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

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

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

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

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

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

/s/ JAMES W. CHRISTMAS

James W. Christmas
President and Chief Executive Officer

March 27, 2003

I, Frederick Dwyer, certify that:

1. I have reviewed this annual report on Form 10-K of KCS Energy, Inc.;

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

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

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

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

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

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

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

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

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

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

/s/ FREDERICK DWYER

Frederick Dwyer
Vice President, Controller and Secretary
(Principal Financial Officer and Principal Accounting Officer)

March 27, 2003

Corporate Directory

Directors

JAMES W. CHRISTMAS[3]
President and Chief Executive Officer, KCS Energy, Inc.

G. STANTON GEARY[2]
Proprietor, Gemini Associates Venture Capital Consulting Firm

JAMES E. MURPHY, JR.[1]
Political Consultant

ROBERT G. RAYNOLDS[2]
Consulting Geologist

JOEL D. SIEGEL[1,3]
President, Orloff, Lowenbach, Stifelman & Siegel, P.A. Attorneys-at-Law

CHRISTOPHER A. VIGGIANO[1,2]
President and Chairman, O'Bryan Glass Corporation Specialty Glass Manufacturer

[1]Member Compensation Committee
[2]Member Audit Committee
[3]Member Executive Committee

Corporate Officers

JAMES W. CHRISTMAS
President and Chief Executive Officer

WILLIAM N. HAHNE
Executive Vice President and Chief Operating Officer

HARRY LEE STOUT
Senior Vice President, Marketing and Risk Management

FREDERICK DWYER
Vice President, Controller and Secretary

JULIE A. SMITH
Vice President, Human Resources

Principal Operating Officers

CLIFF S. FOSS, JR.
Senior Vice President, Gulf Coast Exploration

S. WESLEY VANNATTA
Vice President, Gulf Coast Engineering and Operations

D. BRAD MAGILL
Vice President, Mid-Continent Exploration

H. WELDON HOLCOMBE
Vice President, Mid-Continent Engineering and Operations

D.R. DEFFENBAUGH
Vice President, Mid-Continent Land

DAVID E. CHANDLER
Vice President, Operations Controller

Corporate Office

KCS Energy, Inc.
5555 San Felipe
Suite 1200
Houston, TX 77056
(713) 877-8006
FAX (713) 877-1372

Principal Operating Offices

Gulf Coast Operations
5555 San Felipe
Suite 1200
Houston, TX 77056
(713) 877-8006
FAX (713) 964-9463

Mid-Continent Operations
7130 S. Lewis Avenue
Suite 700
Tulsa, OK 74136
(918) 488-8283
FAX (918) 488-8182

Website

Visit our website at
www.kcsenergy.com

Stockholder Information

Common Stock
The common stock of KCS Energy, Inc. is traded on the New York Stock Exchange under the symbol "KCS."

Listed below are the high and low closing sales prices furnished by the NYSE for the periods indicated.

Registrar and Transfer Agent
Registrar and Transfer Company
10 Commerce Drive
Cranford, NJ 07016
(908) 272-8511

2002		Jan. - Mar.	Apr. - June	July - Sept.	Oct. - Dec.
Market Price	High	$3.32	$ 4.01	$2.70	$2.25
	Low	$1.63	$ 1.75	$1.14	$1.15
2001		**Jan. - Mar.**	**Apr. - June**	**July - Sept.**	**Oct. - Dec.**
Market Price	High	$6.50	$10.20	$6.74	$4.00
	Low	$4.19	$ 5.24	$2.91	$2.53

KCS

KCS Energy, Inc.
5555 San Felipe
Suite 1200
Houston, TX 77056
(713) 877-8006