SPINNAKER EXPLORATION CO
Form 10-K
March 26, 2003

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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[X] Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2002.

[_] Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the transition period from to

Commission file number 001-16009

SPINNAKER EXPLORATION COMPANY
(Exact name of registrant as specified in its charter)

Delaware	76-0560101
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1200 Smith Street, Suite 800 Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

(713) 759-1770
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Securities Exchange Act of 1934:

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

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

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant on June 30, 2002 was approximately $943.6 million.

The number of shares outstanding of the registrant's Common Stock, par value $0.01 per share, on March 25, 2003 was 33,193,944.

Parts of the registrant's Definitive Proxy Statement for its 2003 Annual Meeting of Stockholders are incorporated by reference into Part III of this annual report on Form 10-K.

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Spinnaker Exploration Company ("Spinnaker" or the "Company") has provided definitions for some of the natural gas and oil industry terms used in this report in the "Glossary of Natural Gas and Oil Terms" on page 12.

Cautionary Statement About Forward-Looking Statements

Some of the information in this annual report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). The forward-looking statements speak only as of the date made, and the Company undertakes no obligation to update such forward-looking statements. These forward-looking statements may be identified by the use of the words "believe," "expect," "anticipate," "will," "contemplate," "would" and similar expressions that contemplate future events. These future events include the following matters:

- financial position;
- business strategy;
- budgets;
- amount, nature and timing of capital expenditures, including future development costs;
- drilling of wells;
- natural gas and oil reserves;
- timing and amount of future production of natural gas and oil;
- operating costs and other expenses;
- cash flow and anticipated liquidity;
- prospect development and property acquisitions; and
- marketing of natural gas and oil.

Numerous important factors, risks and uncertainties may affect the Company's operating results, including:

- the risks associated with exploration;
- delays in anticipated start-up dates;
- the ability to find, acquire, market, develop and produce new properties;
- natural gas and oil price volatility;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;
- downward revisions of proved reserves and the related negative impact on the depreciation, depletion and amortization rate;
- production and reserves concentrated in a small number of properties;
- operating hazards attendant to the natural gas and oil business;
- drilling and completion risks, which costs are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells;
- impact of weather conditions on timing and costs of operations;
- availability and cost of material and equipment;
- actions or inactions of third-party operators of the Company's properties;
- the ability to find and retain skilled personnel;
- availability of capital;
- the strength and financial resources of competitors;
- regulatory developments;
- environmental risks; and
- general economic conditions.

Any of the factors listed above and other factors contained in this annual report could cause the Company's actual results to differ materially from the results implied by these or any other forward-looking statements made by the Company or on its behalf. The Company cannot provide assurance that future results will meet its expectations. You should pay particular attention to the risk factors and cautionary statements described under "Risk Factors" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

PART I

Item 1. Business

General

Spinnaker Exploration Company, a Delaware corporation, is an independent energy company engaged in the exploration, development and production of natural gas and oil in the U.S. Gulf of Mexico ("Gulf of Mexico"). Spinnaker's Chief Executive Officer, Warburg, Pincus Ventures, L.P. ("Warburg") and Petroleum Geo-Services ASA ("PGS") formed Spinnaker in December 1996.

At December 31, 2002, the Company had license rights to approximately 14,000 blocks of mostly contiguous 3-D seismic data in the Gulf of Mexico. This database covers an area of approximately 40 million acres, which the Company believes is one of the largest 3-D seismic databases of any independent exploration and production company in the Gulf of Mexico. As of December 31, 2002, the Company had 293 leasehold interests located in federal and Texas state waters of the Gulf of Mexico covering approximately 1,293,000 gross and 742,000 net acres. Within its current inventory of leasehold interests, the Company has identified and captured approximately 125 exploratory prospects. Based on 3-D seismic analysis on blocks where it currently has no leasehold interest, the Company also has identified over 200 leads that may result in additional prospects. The Company believes its regional 3-D seismic approach allows it to create and maintain a large inventory of high-quality prospects and provides the opportunity to enhance its exploration success and efficiently deploy its capital resources. The Company also believes its license rights to large quantities of high-quality seismic data and its management and technical staff are important factors for its current and future success.

From inception through December 31, 2002, the Company participated in drilling 120 wells in the Gulf of Mexico resulting in 70 discoveries. As of December 31, 2002, Ryder Scott Company, L.P. estimated the Company's net proved reserves at approximately 323.6 Bcfe. Spinnaker's current capital expenditure budget for 2003 is $250.0 million, including approximately $94.0 million for exploration activities, $114.0 million for development activities, $38.0 million for leasehold acquisitions and geological and geophysical expenditures and $4.0 million for other property and equipment. The Company currently plans to drill 18 wells on the shelf and 14 wells in the deep water in 2003. Exploration and development in deep water requires significant capital commitments. If the Company is successful in its deepwater exploration efforts in 2003, currently budgeted capital requirements for development activities in 2003 will increase.

Spinnaker has a 25% non-operator working interest in a significant deepwater oil discovery on Green Canyon Blocks 338/339 ("Front Runner"). The Company participated in six consecutive successful wells and sidetracks to test the reservoirs on these blocks through December 31, 2002. Of the Company's total proved reserves as of December 31, 2002, 70% were proved undeveloped reserves. Front Runner represented more than 60% of total proved undeveloped reserves. Spinnaker has incurred capital expenditures associated with Front Runner of $70.2 million through December 31, 2002 and expects to incur an aggregate of approximately $67.0 million in future development costs during 2003 and 2004. First production is anticipated during the summer of 2004.

On April 3, 2002, the Company completed a public offering of 5,750,000 shares of common stock, par value $0.01 per share ("Common Stock"), at $41.50 per share, including the over-allotment option consisting of 750,000 shares. After payment of underwriting discounts and commissions, the Company received net proceeds of $227.9 million. On April 3, 2002, the Company used a portion of the proceeds from the offering to repay outstanding borrowings of $37.0 million. The remaining net proceeds were invested in short-term high quality investments and used to fund a portion of the costs to develop Front Runner, to fund a portion of exploration and other development activities and for general corporate purposes.

Spinnaker files reports with the Securities and Exchange Commission ("Commission") on Forms 10-K, 10-Q and 8-K. The public may read and copy any materials that the Company files with the Commission at the

Commission's public reference room. The public may also access Spinnaker's annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished to the Commission pursuant to Section 13(a) or 15(d) of the Exchange Act on its internet website at www.spinnakerexploration.com, free of charge, as soon as reasonably practicable after Spinnaker electronically files or furnishes such material with or to the Commission.

Business Strategy

Spinnaker's goals are to expand its reserve base, increase cash flow and net income and to generate an attractive return on capital. The Company emphasizes the following elements in its strategy to achieve these goals:

- Focus on the Gulf of Mexico
- Maintain a large database of 3-D seismic data
- Employ a rigorous prospect selection process
- Emphasize technical expertise
- Sustain a balanced, diversified exploration effort while maintaining a conservative balance sheet.

Focus on the Gulf of Mexico. Spinnaker has assembled a large 3-D seismic database and focuses its exploration activities exclusively in the Gulf of Mexico because it believes this area represents one of the most attractive exploration regions in North America. The Gulf of Mexico has the following characteristics that make it attractive to exploration and production companies:

- Prolific exploration and production history
- Access to acreage
- Existing oilfield service infrastructure
- Attractive taxation and royalty rates
- Relatively high-productivity wells
- Transportation infrastructure with geographic proximity to well-developed markets for natural gas and oil
- Geologic diversity that offers a variety of exploration opportunities.

The Company also believes its geographic focus provides an excellent opportunity to develop and maintain competitive advantages through the combination of its 3-D seismic database and regional exploration and operating expertise.

Maintain a large database of 3-D seismic data. Spinnaker believes its large database of original and reprocessed 3-D seismic data allows it to generate and maintain a large inventory of high-quality exploratory prospects. The Company's 3-D seismic database serves as the foundation for its exploration program. The Company will continue to supplement this database with 3-D seismic data acquisitions from various seismic data vendors and upgrade and improve the existing 3-D seismic data through reprocessing.

Employ a rigorous prospect selection process. Spinnaker uses its large inventory of contiguous areas of 3-D seismic data to select prospects by tying regional 3-D seismic analysis to existing well control. Through this process, the Company enhances its understanding of the geology before selecting prospects and increases the probability of accurately identifying hydrocarbon-bearing zones.

Emphasize technical expertise. Spinnaker's 15 explorationists have an average of over 20 years experience in exploration in the Gulf of Mexico. Spinnaker also has a team of six technical specialists with significant experience in reprocessing seismic data, petrophysics and geologic modeling and inversion. In its efforts to attract and retain explorationists and technical specialists, the Company offers an entrepreneurial culture, an extensive 3-D seismic database, state-of-the-art computer-aided exploration technology and other technical tools.

Spinnaker generally retains larger working interests in prospects located in water depths of less than 2,000 feet. The combination of larger working interests and its technical expertise has allowed the Company to act as the operator for a majority of these prospects, providing more control of costs, the timing and amount of capital expenditures and the selection of technology.

Sustain a balanced, diversified exploration effort while maintaining a conservative balance sheet. Spinnaker believes that its exploration approach results in portfolio balance and diversity among:

- shallow water, or water depths of less than 600 feet, and deepwater prospects;
- shallow drilling depth prospects and deep drilling depth prospects; and
- lower-risk, lower-potential prospects and higher-risk, higher-potential prospects.

The broad coverage of the Gulf of Mexico by the Company's 3-D seismic data allows it to participate in a variety of geologically diverse exploration opportunities and to create a diversified prospect portfolio. The Company intends to manage its exposure in deepwater exploration activities by focusing on prospects where commercial feasibility of the prospect can be evaluated with a small number of wells and where it believes 3-D seismic analysis provides attractive risk/reward benefits. The Company also strives to diversify its exploration efforts by seeking to limit the budgeted amount of the leasehold acquisition and drilling costs of the first exploratory well on any one prospect to less than 10% of the annual capital budget.

The Company believes that maintaining continuity in its exploration activity during all phases of the commodity price cycles is an important element to balance and diversification. By positioning the Company to have a continuous exploration program, it can potentially take advantage of reduced competition for prospects and lower drilling and other oilfield service costs during periods of low natural gas and oil prices. Drilling deep depth prospects and drilling in deep water is inherently more risky than drilling shallow depth prospects and drilling in shallow water. Spinnaker's emphasis on maintaining a lower debt-to-capitalization ratio than many of its peers has enhanced its ability to pursue this strategy.

Seismic Data Agreements

Data Covered by Seismic Data Agreements

The initial data agreement with PGS provided Spinnaker with a minimum of approximately 3,700 blocks of 3-D seismic data. The Company has acquired an additional 10,300 blocks of standard and enhanced 3-D seismic data from various seismic contractors, including approximately 3,900 blocks from PGS. The Company's 3-D seismic database included a total of approximately 8,300 blocks of standard data and 5,700 blocks of enhanced data as of December 31, 2002.

Seismic contractors acquire both proprietary and multi-client marine seismic data. When a seismic contractor acquires proprietary data, it does so on an exclusive contractual basis for its customers. When a seismic contractor acquires multi-client data, it owns the data itself and licenses the possession and use of copies of the data to the industry at large for a fee. Most of the standard data that Spinnaker is entitled to use is multi-client seismic data. Some of Spinnaker's enhanced data is proprietary, internally-reprocessed seismic data.

Standard data is the basic 3-D, post-stack time-migrated seismic data provided as the standard product to customers by seismic contractors. Enhanced data is created through additional computer processing of standard data and includes processed data referred to as pre-stack depth-migrated data, 3-D amplitude versus offset

processing, refined pre-stack time-migrated data and several seismic attributes used for geologic delineation, rock property analysis and pore pressure prediction.

Rights to Use the Data

In general, the Company may use the multi-client data from its seismic contractors as follows:

- for its internal needs, including using the data in connection with the drilling of wells or the acquiring of interests in natural gas or oil properties;

- to make maps and other work products from the data;

- to make the data and work product available to the Company's consultants and contractors for interpretation, analysis, evaluation, mapping and additional processing, provided that the data and work product are held in confidence by those individuals; and

- to show data and work products to prospective and existing investors and participants in farm-outs and exploration or development groups for the sole purpose of evaluating their participation in such ventures, provided that the data and work product are held in confidence by those individuals.

The data agreements provide that the Company's rights to use the seismic data continue for at least 25 years from the date of purchase subject to certain termination provisions discussed below. The data the Company receives under any data agreement remains the property of that seismic contractor subject to the rights granted to the Company in the data agreement.

Restrictions on Transfer and Assignment

The various seismic data agreements provide provisions for transfer of data licenses in the event the Company merges with or is acquired by another company. In some cases, the Company will incur fees for the transfer of these licenses.

Termination Events

In general, a seismic contractor may terminate substantially all of the Company's rights under a data agreement by giving Spinnaker notice after the occurrence of certain events, such as:

- the Company transfers data or its rights under the data agreement in violation of the data agreement;

- a competitor of the seismic contractor acquires control of the Company;

- a second major customer of the seismic contractor acquires control of the Company after an initial major customer of the seismic contractor has previously acquired control of the Company;

- the Company knowingly breaches one of the provisions of the data agreement relating to the use, transfer or disclosure of the data;

- the Company unknowingly breaches one of the previously mentioned provisions of the data agreement and the Company fails to diligently prevent a subsequent breach after it receives notice of the first breach;

- the Company commits a material breach of one of the other provisions of the data agreement and fails to remedy the breach after notice to the Company; or

- the Company commences a voluntary bankruptcy or similar proceeding or an involuntary bankruptcy or similar proceeding is commenced against the Company and remains un-dismissed for 30 days.

Use of Computer-Aided Exploration Technology

Computer-aided exploration is the process of using a computer workstation and common database to accumulate and analyze seismic, production and other data regarding a geographic area. In general, computer-aided exploration involves accumulating 3-D seismic data, as well as 2-D data in some cases, with respect to a potential drilling location and correlating that data with historical well control and production data from similar properties. The available data is then analyzed using computer software and modeling techniques to project the likely geologic setting of a potential drilling location and potential locations of undiscovered natural gas and oil reserves. This process relies on a comparison of actual data for the potential drilling location and historical data for the density and sonic characteristics of different types of rock formations, hydrocarbons and other subsurface minerals, resulting in a projected 3-D image of the subsurface. This modeling is performed through the use of advanced interactive computer workstations and various combinations of available computer software developed solely for this application.

The Company has invested extensively in the advanced computer hardware and software necessary for 3-D seismic exploration. The Company's explorationists can access a diverse software tool kit including modeling, mapping, well path description, time slice analysis, pre- and post-stack seismic processing, synthetic generation, fluid replacement studies and seismic attribute analyses.

Marketing

The Company sells its natural gas and oil production under fixed or floating market price contracts. Revenues, profitability, cash flow and future growth depend substantially on prevailing prices for natural gas and oil. The prices received by the Company for its natural gas and oil production fluctuates widely. For example, natural gas prices increased significantly in the second half of 2002 after a sharp decline in 2001 from levels reached in the second half of 2000 and early 2001. Oil prices have also increased recently as compared to prior years. Among the factors that can cause this fluctuation are the level of consumer product demand, weather conditions, domestic and foreign governmental regulations, the price and availability of alternative fuels, political conditions and actual or threatened acts of war, terrorism or hostilities in oil producing regions, the domestic and foreign supply of natural gas and oil, the price of foreign imports and overall economic conditions.

Decreases in the prices of natural gas and oil could adversely affect the carrying value of proved reserves and revenues, profitability and cash flow. Although the Company is not currently experiencing any significant involuntary curtailment of natural gas or oil production, market, economic and regulatory factors may in the future materially affect its ability to sell natural gas or oil production. For the year ended December 31, 2002, sales to Duke Energy Trade and Marketing LLC, Cinergy Marketing & Trading LP, Equiva Trading Company and Kinder Morgan Ship Channel Pipeline LP accounted for approximately 52%, 13%, 11% and 11%, respectively, of the Company's natural gas and oil revenues, excluding the effects of hedging activities. For the year ended December 31, 2001, sales to Enron North America Corp., Tejas Gas Marketing, LLC, Reliant Energy Services, Inc. and Bridgeline Gas Marketing LLC accounted for approximately 32%, 23%, 21% and 17%, respectively, of the Company's natural gas and oil revenues, excluding the effects of hedging activities. For the year ended December 31, 2000, sales to Enron North America Corp., Coral Energy Resources, L.P. and Reliant Energy Services, Inc. accounted for approximately 61%, 11% and 11%, respectively, of the Company's natural gas and oil revenues, excluding the effects of hedging activities. Spinnaker no longer sells its natural gas and oil production to Enron North America Corp. Spinnaker believes the loss of this customer has not materially affected its ability to market its natural gas and oil production.

Customers purchase all of the Company's natural gas production at current market prices. The terms of the arrangements require the customers to pay the Company within 60 days after delivery of the production. As a result, if the customers were to default on their payment obligations to the Company, near-term earnings and cash flows would be adversely affected. However, due to the availability of other markets and pipeline connections, the Company does not believe that the loss of these customers or any other single customer would adversely affect its ability to market production.

Spinnaker enters into hedging arrangements from time to time to reduce its exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. However, these contracts also limit the benefits the Company would realize if prices increase. These financial arrangements take the form of swap contracts or cashless collars and are placed with major trading counterparties the Company believes represent minimal credit risks. Spinnaker cannot provide assurance that these trading counterparties will not become credit risks in the future. For further information concerning Spinnaker's hedging transactions, see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk." Under its current hedging policy, the Company generally does not hedge more than 66 2/3% of its estimated twelve-month production quantities without the prior approval of the risk management committee of the board of directors.

Competition

The Company competes with major and independent natural gas and oil companies for leasehold acquisitions. Spinnaker also competes for the equipment and labor required to operate and develop these properties. Most of the Company's competitors have substantially greater financial and other resources. As a result, in the deep water where exploration is more expensive, competitors may be better able to withstand sustained periods of unsuccessful drilling. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than Spinnaker can, which would adversely affect Spinnaker's competitive position. These competitors may be able to pay more for exploratory prospects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than the Company can. The Company's ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend upon its ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, most of the Company's competitors have been operating in the Gulf of Mexico for a much longer time than the Company has and have demonstrated the ability to operate through industry cycles.

Regulation

Federal Regulation of Sales and Transportation of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the regulations promulgated thereunder by the Federal Energy Regulatory Commission ("FERC"). In the past, the federal government has regulated the prices at which natural gas could be sold. Deregulation of natural gas sales by producers began with the enactment of the Natural Gas Policy Act of 1978. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining Natural Gas Act of 1938 and Natural Gas Policy Act of 1978 price and non-price controls affecting producer sales of natural gas effective January 1, 1993. Congress could, however, re-enact price controls in the future.

The Company's sales of natural gas are affected by the availability, terms and cost of pipeline transportation. The price and terms for access to pipeline transportation remain subject to extensive federal regulation. Commencing in April 1992, the FERC issued Order No. 636 and a series of related orders that required interstate pipelines to provide open-access transportation on a basis that is equal for all natural gas suppliers. The FERC has stated that it intends for Order No. 636 and its future restructuring activities to foster increased competition within all phases of the natural gas industry. Although Order No. 636 does not directly regulate the Company's production and marketing activities, it does affect how buyers and sellers gain access to the necessary transportation facilities and how the Company and its competitors sell natural gas in the marketplace. The courts have largely affirmed the significant features of Order No. 636 and the numerous related orders pertaining to individual pipelines. The FERC continues to review and modify its regulations regarding the transportation of natural gas. In 2000, the FERC issued Order No. 637 and subsequent orders, which Spinnaker refers to collectively as "Order No. 637." Order No. 637 imposes a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC pricing policy

by waiving price ceilings for short-term released capacity for a two-year period ending September 30, 2002, and effected changes in the FERC regulations relating to scheduling procedures, capacity segmentation, pipeline penalties, rights of first refusal and information reporting. Several parties subsequently filed appeals in the Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") seeking court review of various aspects of Order 637, particularly (i) the right of customers to segment their contractual capacity in a manner that allows a forwardhaul/backhaul to a single point and (ii) the rights of first refusal granted to existing customers to extend contracts beyond the end of the contract's term. On April 5, 2002, the D.C. Circuit generally affirmed Order No. 637 but remanded certain issues to the FERC, including the forwardhaul/backhaul and the rights of first refusal issues. The FERC on remand affirmed its position on the forwardhaul/backhaul issue but reversed itself on the rights of first refusal issue. Requests for rehearing of this order are currently pending at the FERC.

Order No. 637 also required interstate natural gas pipelines to implement the policies mandated by the order through individual compliance filings. The FERC has now ruled on a number of the individual compliance filings, although its decisions in such proceedings remain subject to the outcome of pending rehearing requests and possible court appeals.

In addition, the FERC implemented new regulations governing the procedure for obtaining authorization to construct new pipeline facilities and has issued a policy statement, which it largely affirmed in recent orders on rehearing, establishing a presumption in favor of requiring owners of new pipeline facilities to charge rates based solely on the costs associated with such new pipeline facilities. The Company cannot predict what further action the FERC will take on these matters, nor can it accurately predict whether the FERC's actions will achieve the goal of increasing competition in markets in which natural gas is sold. However, the Company does not believe that any action taken will affect it in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers.

The Outer Continental Shelf Lands Act ("OCSLA") requires that all pipelines operating on or across the Outer Continental Shelf provide open-access, non-discriminatory service. Although the FERC has opted not to impose the regulations of Order No. 509, in which the FERC implemented the OCSLA, on gatherers and other non-jurisdictional entities, the FERC has retained the authority to exercise jurisdiction over those entities if necessary to permit non-discriminatory access to service on the Outer Continental Shelf. The FERC recently issued Order No. 639, requiring that virtually all non-proprietary pipeline transporters of natural gas on the Outer Continental Shelf report information on their affiliations, rates and conditions of service. Among the FERC's stated purposes in issuing such rules was the desire to provide shippers on the Outer Continental Shelf with greater assurance of open-access services on pipelines located on the Outer Continental Shelf and non-discriminatory rates and conditions of service on such pipelines. A federal district court determined that the FERC has exceeded its statutory authority in promulgating Order Nos. 639 and 639-A, and the court permanently enjoined the FERC from enforcing the orders. The FERC's appeal of the district court's decision is currently pending at the D.C. Circuit.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

Federal Leases

A substantial portion of the Company's operations is located on federal natural gas and oil leases, which are administered by the Minerals Management Service ("MMS"). Such leases are issued through competitive bidding, contain relatively standardized terms and require compliance with detailed MMS regulations and orders pursuant to the OCSLA that are subject to interpretation and change by the MMS. For offshore operations, lessees must obtain MMS approval for exploration plans and development and production plans prior to the commencement of such operations. In addition to permits required from other agencies such as the Coast Guard,

the Army Corps of Engineers and the Environmental Protection Agency, lessees must obtain a permit from the MMS prior to the commencement of drilling. The MMS has promulgated regulations requiring offshore production facilities located on the Outer Continental Shelf to meet stringent engineering and construction specifications. The MMS also has regulations restricting the flaring or venting of natural gas. Similarly, the MMS has promulgated other regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all production facilities. To cover the various obligations of lessees on the Outer Continental Shelf, the MMS generally requires that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be met. The cost of these bonds or other surety can be substantial, and there is no assurance that bonds or other surety can be obtained in all cases. The Company is currently in compliance with the bonding requirements of the MMS. Under some circumstances, the MMS may require any of the Company's operations on federal leases to be suspended or terminated. Any such suspension or termination could materially adversely affect the Company's financial condition and results of operations.

The MMS has issued a final rule that governs the calculation of royalties and the valuation of crude oil produced from federal leases. This rule amends the way that the MMS values crude oil produced from federal leases for determining royalties by eliminating posted prices as a measure of value and relying instead on arm's-length sales prices and spot market prices as indicators of value. The lawfulness of the new rule has been challenged at the D.C. Circuit. The Company cannot predict whether this new rule will be upheld in federal court, nor can the Company predict whether the MMS will take further action on this matter. The Company believes this rule will not have a material impact on its financial condition, liquidity or results of operations.

State and Local Regulation of Drilling and Production

The Company owns interests in properties located in the state waters of the

Gulf of Mexico offshore Texas and occasionally may conduct operations in the state waters offshore Louisiana and Mississippi. These states regulate drilling and operating activities by requiring, among other things, drilling permits and bonds and reports concerning operations. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposal of waste materials, unitization and pooling of natural gas and oil properties and establishment of maximum rates of production from natural gas and oil wells. Some states prorate production to the market demand for natural gas and oil.

Oil Price Controls and Transportation Rates

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 may be affected by the cost of transporting the products to market. Effective as of January 1, 1995, the FERC implemented regulations generally grandfathering all previously unchallenged interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. As required by its own regulations, in July 2000, the FERC issued a Notice of Inquiry seeking comment on whether to retain or to change the existing methodology underlying its then current indexing system, which was based on the Producer Price Index for Finished Goods ("PPI-FG") minus one percent. In December of 2000, the FERC issued an order concluding that the PPI-FG minus one percent methodology reasonably estimated the actual cost changes in the pipeline industry and should be continued for another five-year period, subject to review in July 2005. In February 2003, on remand of its December 2000 order from the D.C. Circuit, the FERC changed the rate indexing methodology to the PPI-FG, but without the subtraction of 1% as had been done previously. The FERC made the change prospective only, but did allow oil pipelines to recalculate their maximum ceiling rates as though the new rate indexing methodology had been in effect since July 1, 2001. The FERC's regulation of oil transportation rates may tend to increase the cost of transporting oil and natural gas liquids by interstate pipeline, although the annual adjustments may result in decreased rates in a given year. The Company is unable at this time to predict the effects of these regulations, if any, on the transportation costs associated with oil production from its properties. However, the Company does not believe that these regulations affect it any differently than other producers.

Environmental Regulations

The Company's operations are subject to numerous stringent and complex laws and regulations at the federal, state and local levels governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may:

- require acquisition of a permit before drilling commences;
- restrict the types, quantities and concentrations of various materials that can be released into the environment in connection with drilling and production activities;
- limit or prohibit construction or drilling activities in certain ecologically sensitive and other protected areas;
- require remedial action to prevent pollution from former operations; and

- impose substantial liabilities for pollution resulting from the Company's operations.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of remedial requirements and the imposition of injunctions to force future compliance. Moreover, public interest in the protection of the environment has increased dramatically in recent years. Offshore drilling in some areas has been opposed by environmental groups and, in some areas, has been restricted. To the extent laws are enacted or other governmental action is taken that prohibits or restricts offshore drilling or imposes environmental protection requirements that result in increased costs to the natural gas and oil industry in general and the offshore drilling industry in particular, the Company's business and prospects could be adversely affected.

The Oil Pollution Act of 1990 ("OPA") and regulations thereunder impose a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A "responsible party" includes the owner or operator of a facility or vessel, or the lessee or permittee of the area in which an offshore facility is located. The OPA imposes strict, joint and several liability on responsible parties for oil removal costs and a variety of public and private damages, including natural resource damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Even if applicable, the liability limits for offshore facilities require the responsible party to pay all removal costs, plus up to $75.0 million in other damages. Few defenses exist to the liability imposed by the OPA.

The OPA also requires a responsible party to submit proof of its financial ability to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. As amended by the Coast Guard Authorization Act of 1996, the OPA requires parties responsible for offshore facilities to provide financial assurance in the amount of $35.0 million to cover potential OPA liabilities. This amount can be increased up to $150.0 million in certain limited circumstances where the MMS believes such an amount is justified based on the operational, environmental, human health and other risks posed by the quantity or quality of oil that is explored for, drilled for or produced by the responsible party. The Company is in compliance with its financial assurance obligations.

The OPA also imposes other requirements, such as the preparation of oil spill response plans. The Company has such plans in place. The Company is also regulated by the Clean Water Act and similar state laws. The Clean Water Act prohibits any discharge into waters of the United States except in strict conformance with permits issued by federal and state agencies. Failure to comply with the ongoing requirements of these laws or inadequate cooperation during a spill event may subject a responsible party to administrative, civil or criminal enforcement actions.

In addition, the OCSLA authorizes regulations relating to safety and environmental protection applicable to lessees and permittees operating on the Outer Continental Shelf. Specific design and operational standards may apply to Outer Continental Shelf vessels, rigs, platforms, vehicles and structures. Violations of lease conditions or regulations issued pursuant to the OCSLA can result in substantial civil and criminal penalties, as well as potential court injunctions curtailing operations and the cancellation of leases.

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the "Superfund" law, and analogous state laws impose liability, without regard to fault or the legality of the original conduct, on some classes of persons that are considered to have contributed to 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 found at the site. Persons who are or were responsible for releases of hazardous substances under the CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. Additionally, it is not uncommon for neighboring landowners and other third parties to file tort claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Company's operations are also subject to regulation of air emissions under the Clean Air Act, comparable state and local requirements and the OCSLA. Future regulations under these laws could lead to the gradual imposition of new air pollution control requirements on the Company's operations. The Company does not believe that its operations would be materially affected by any such requirements, nor does it expect such requirements to be any more burdensome to it than to other companies of its size involved in natural gas and oil exploration and production activities.

In addition, legislation has been proposed in Congress from time to time that would reclassify some natural gas and oil exploration and production wastes as "hazardous wastes," which would make the reclassified wastes subject to more stringent handling, disposal and clean-up requirements. If Congress were to enact this legislation, it could increase the Company's operating costs, as well as those of the natural gas and oil industry in general.

Management believes that the Company is in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on its results of operations.

Operating Hazards and Insurance

The natural gas and oil business involves a variety of operating risks, including fires, explosions, blow-outs and surface cratering, uncontrollable flows of underground natural gas, oil and formation water, natural disasters, pipe or cement failures, casing collapses, embedded oilfield drilling and service tools, abnormally pressured formations and environmental hazards such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases. If any of these events occur, the Company could incur substantial losses as a result of injury or loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of the Company's operations and repairs to resume operations. If the Company experiences any of these problems, it could affect well bores, platforms, gathering systems and processing facilities, which could adversely affect its ability to conduct operations.

As part of its strategy, the Company explores for natural gas and oil in the deep waters of the Gulf of Mexico where operations are more difficult than in shallower waters. The Company's deepwater drilling and operations require the application of recently developed technologies that involve a higher risk of mechanical failure. Furthermore, the deep waters of the Gulf of Mexico lack the physical and oilfield service infrastructure present in the shallower waters.

As a result, deepwater operations may require a significant amount of time between a discovery and the time that the Company can market the natural gas or oil, increasing the risks involved with these operations.

Offshore operations are also subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, the Company could incur substantial liabilities that could reduce or eliminate the funds available for exploration, development or leasehold acquisitions, or result in loss of properties.

In accordance with industry practice, the Company maintains insurance against some, but not all, potential risks and losses. Management reviews Spinnaker's coverage at least annually. For some risks, the Company may not obtain insurance if it believes the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect the Company.

Employees

At December 31, 2002, the Company had 65 full-time employees. The Company believes that it maintains excellent relationships with its employees. None of the Company's employees is covered by a collective bargaining agreement. From time to time, the Company uses the services of independent consultants and contractors to perform various professional services, particularly in the areas of construction, design, well-site surveillance, permitting and environmental assessment. Independent contractors usually perform field and on-site production operation services for the Company, including pumping, maintenance, dispatching, inspection and testing.

GLOSSARY OF NATURAL GAS AND OIL TERMS

The following is a description of the meanings of some of the natural gas and oil industry terms used in this annual report.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, of crude oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Block. A block depicted on the Outer Continental Shelf Leasing and Official Protraction Diagrams issued by the U.S. Minerals Management Service or a similar depiction on official protraction or similar diagrams issued by a state bordering on the Gulf of Mexico.

Btu or British Thermal Unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development well. A well drilled into a proved natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploratory well. A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

Farm-in or farm-out. An agreement under which the owner of a working interest in a natural gas and oil lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farm-in" while the interest transferred by the assignor is a "farm-out."

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

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

Lead. A specific geographic area which, based on supporting geological, geophysical or other data, is deemed to have potential for the discovery of commercial hydrocarbons.

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMBls. Million barrels of crude oil or other liquid hydrocarbons.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

MMcfe. Million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or wells, as the case may be.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed non-producing reserves. Proved developed reserves expected to be recovered from zones behind casing in existing wells.

Proved developed producing reserves. Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production to market.

Proved developed reserves. Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Proved reserves. The estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

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

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether or not such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

Item 2. Properties

Since inception, the Company has concentrated on the exploration for natural gas and oil exclusively in the Gulf of Mexico. As of December 31, 2002, proved reserves associated with Spinnaker's discoveries were located on 30 different blocks, including one property in which the Company has only a royalty interest, with production established from 26 blocks. Spinnaker operates 41 of its 70 discoveries, and the Company's working interests in these wells range from 12.5% to 100%. Six blocks account for approximately 73% of the Company's total proved reserves.

As of December 31, 2002, the Company had license rights to approximately 14,000 blocks of mostly contiguous 3-D seismic data in the Gulf of Mexico. This database covers an area of approximately 40 million acres, which the Company believes is one of the largest 3-D seismic databases of any independent exploration and production company in the Gulf of Mexico. As of December 31, 2002, the Company had 293 leasehold interests located in federal and Texas state waters of the Gulf of Mexico covering approximately 1,293,000 gross and 742,000 net acres.

Natural Gas and Oil Reserves

Spinnaker has a 25% non-operator working interest in its significant deepwater oil discovery at Front Runner. The Company participated in six consecutive successful wells and sidetracks in testing the reservoirs on these blocks through December 31, 2002. Of the Company's total proved reserves as of December 31, 2002, 70% were proved undeveloped reserves. Front Runner represented more than 60% of total proved undeveloped reserves.

The following table presents estimated net proved natural gas and oil reserves and the related net present value of the reserves at December 31, 2002 as prepared by Ryder Scott Company, L.P. The present value of future net cash flows (before income taxes) discounted at 10% and the standardized measure of discounted future net cash flows shown in the table are not intended to represent the current market value of the estimated natural gas and oil reserves Spinnaker owns. For further information concerning the present value of future net cash flows associated with these proved reserves, see Note 14 of the Notes to Consolidated Financial Statements.

The present value of future net cash flows and the standardized measure of discounted future net cash flows as of December 31, 2002 was determined by using prices of $4.91 per Mcf of natural gas and $30.50 per barrel of oil as of December 31, 2002.

	Proved Reserves		
	Developed	Undeveloped	Total
Natural gas (MMcf)	84,139	59,392	143,531
Oil and condensate (MBbls)	2,219	27,789	30,008
Total proved reserves (MMcfe)	97,456	226,121	323,577
Present value of future net cash flows (before income taxes) discounted at 10% (in thousands)(1)	$323,426	$523,847	$847,273
Standardized measure of discounted future net cash flows (in thousands)(1)	$259,878	$420,920	$680,798

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(1) Excludes pre-tax unrealized losses of $19.9 million for the effects of hedging activities using natural gas and oil prices in effect at December 31, 2002.

The process of estimating natural gas and oil reserves is complex. It requires various assumptions, including natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The Company must project production rates and timing of development expenditures. The Company analyzes available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. Therefore, estimates of natural gas and oil reserves are inherently imprecise.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, the Company may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond the Company's control. At December 31, 2002, approximately 82% of the Company's proved reserves were either undeveloped or non-producing. Because most of the reserve estimates are not based on a lengthy production history and are calculated using volumetric analysis, these estimates are less reliable than estimates based on a lengthy production history.

At December 31, 2002, approximately 70% of the Company's proved reserves were undeveloped and primarily related to Front Runner. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. The reserve data assumes that the Company will make these expenditures. Although the Company estimates its reserves and the costs associated with developing them in accordance with industry standards, the estimated costs may be inaccurate, development may not occur as scheduled and results may not be as estimated.

It should not be assumed that the present value of future net cash flows is the current market value of the Company's estimated natural gas and oil reserves. In accordance with requirements of the Commission, the Company bases the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

Volumes, Prices and Operating Expenses

The following table presents information regarding the production volumes of, average sales prices received for and average production costs associated with Spinnaker's sales of natural gas and oil and condensate for the periods indicated:

	Year Ended December 31,		
	2002	2001	2000
Production:			
Natural gas (MMcf)	45,180	51,234	28,845
Oil and condensate (MBbls)	1,040	310	225
Total (MMcfe)	51,419	53,094	30,194
Average sales price per unit:			
Natural gas revenues from production (per Mcf)	$ 3.46	$ 4.14	$ 4.62
Effects of hedging activities (per Mcf)	0.10	(0.18)	(0.59)
Average price (per Mcf)	$ 3.56	$ 3.96	$ 4.03
Oil and condensate revenues from production (per Bbl)	$ 26.39	$ 24.90	$ 30.14
Effects of hedging activities (per Bbl)	--	--	(7.16)
Average price (per Bbl)	$ 26.39	$ 24.90	$ 22.98
Total revenues from production (per Mcfe)	$ 3.57	$ 4.14	$ 4.64
Effects of hedging activities (per Mcfe)	0.09	(0.18)	(0.62)
Total average price (per Mcfe)	$ 3.66	$ 3.96	$ 4.02

Expenses (per Mcfe):			
Lease operating expenses(1).................................	$ 0.35	$ 0.23	$ 0.30
Depreciation, depletion and amortization--natural gas and oil properties..	$ 2.12	$ 1.60	$ 1.57

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(1) The lease operating expense rate includes $0.03 per Mcfe associated with workovers in 2002, $0.04 per Mcfe associated with workovers in 2001 and $0.03 per Mcfe associated with workovers in 2000.

Development, Exploration and Acquisition Capital Expenditures

The following table presents information regarding Spinnaker's net costs incurred in acquisition, exploration and development activities. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including those in progress, geological and geophysical service costs and depreciation of support equipment used in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines.

	Year Ended December 31,		
	2002	2001	2000
Acquisition costs:			
Unproved....................	$ 39,789	$ 34,524	$ 21,421
Proved......................	--	--	--
Exploration costs..............	163,322	187,720	121,451
Development costs..............	139,368	80,276	51,144
Total costs incurred.....	$342,479	$302,520	$194,016

Drilling Activity

The following table shows Spinnaker's drilling activity. In the table, "gross" refers to the total wells in which the Company has a working interest and "net" refers to gross wells multiplied by the Company's working interest in such wells.

	Year Ended December 31,					
	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive........	11	5.1	17	8.2	16	10.4
Nonproductive.....	11	6.2	16	9.4	12	4.7

Total	22	11.3	33	17.6	28	15.1
Development Wells:						
Productive	3	2.0	2	0.5	--	--
Nonproductive	1	0.4	--	--	--	--
Total	4	2.4	2	0.5	--	--

In 1999, the Company drilled an exploratory well that was preliminarily determined to be unsuccessful and was temporarily abandoned. Upon reprocessing of the seismic data, further analysis of the well and related sidetrack and examination of proved category reserves, the Company determined that the development would be commercial, and the well was reclassified as a discovery in 2000. This well commenced production in 2002.

Since December 31, 2002 and through March 25, 2003, the Company has drilled two gross (1.3 net) productive exploratory wells, one gross (0.3 net) productive development well and one gross (0.5 net) nonproductive exploratory well. As of March 25, 2003, the Company was drilling four gross (1.1 net) exploratory wells and one gross (0.4 net) development well.

Productive Wells

The following table sets forth the number of productive natural gas and oil wells in which Spinnaker owned an interest as of December 31, 2002:

	Total Productive Wells	
	Gross	Net
Natural gas	60	32.1
Oil	10	3.1
Total	70	35.2

Productive wells consist of producing wells and wells capable of production, including wells awaiting pipeline connections to commence deliveries and wells awaiting connection to production facilities.

Acreage Data

The following table presents information regarding developed and undeveloped lease acreage. Developed acreage is considered to be those lease acres that are allocated or assignable to productive wells or wells capable of production. Undeveloped acreage is considered to be those lease acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether or not such acreage contains proved reserves. Spinnaker's developed and undeveloped lease acreage as of December 31, 2002 was as follows (in thousands):

	Developed Acreage		Undeveloped Acreage		Total	
	Gross	Net	Gross	Net	Gross	Net
Federal Waters Offshore Louisiana	60	34	730	370	790	404
Federal Waters Offshore Texas....	58	38	405	284	463	322
Texas State Waters...............	15	5	25	11	40	16
Total........................	133	77	1,160	665	1,293	742

The Company's lease agreements generally terminate if wells have not been drilled on the acreage within a period of five years from the date of the lease if located on the shelf in less than 200 meters of water or ten years if located in the deep waters of the Gulf of Mexico. Excluding lease acreage held by production, average remaining lease terms were 6.3 years, 4.4 years and 1.5 years for leases in federal waters offshore Louisiana, federal waters offshore Texas and Texas state waters, respectively.

Item 3. Legal Proceedings

From time to time, the Company may be a party to various legal proceedings. The Company currently is not a party to any material litigation.

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

The Company did not hold a meeting of stockholders or otherwise submit any matter to a vote of stockholders in the fourth quarter of 2002.

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PART II

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

Spinnaker's Common Stock trades on the New York Stock Exchange under the symbol "SKE." The following table sets forth the range of high and low sales prices per share of Common Stock for each quarter by period.

	Sales Price High	Sales Price Low
2001:		
First Quarter........................	$44.50	$33.00
Second Quarter.......................	$48.00	$36.60
Third Quarter........................	$43.96	$30.00
Fourth Quarter.......................	$45.55	$33.30
2002:		
First Quarter........................	$44.64	$34.45

Second Quarter	$44.89	$35.77
Third Quarter	$36.90	$24.46
Fourth Quarter	$29.71	$18.45
2003:		
First Quarter (through March 25, 2003)	$22.70	$17.15

On March 25, 2003, the closing sale price of Spinnaker's Common Stock, as reported by the New York Stock Exchange, was $18.52 per share. On that date, there were 39 holders of record.

The Company has never declared or paid any dividends on its Common Stock. The Company currently intends to retain future earnings, if any, for the operation and development of its business and does not anticipate paying any dividends on its Common Stock in the foreseeable future. In addition, the Company's $200.0 million credit agreement ("Credit Facility") contains restrictions and limitations on paying cash dividends on its Common Stock. For a description of the covenants and restrictive provisions in the Credit Facility, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations--Liquidity and Capital Resources--Financing Activities" and Note 4 of the Notes to Consolidated Financial Statements.

The table of "Securities Authorized for Issuance Under Equity Compensation Plans" is set forth under "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" and is incorporated by reference herein.

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Item 6. Selected Financial Data

The following table sets forth some of the Company's historical consolidated financial data. The following data should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and Notes thereto included elsewhere herein. The selected consolidated financial data provided below are not necessarily indicative of the future results of operations or financial performance of the Company.

	Year Ended Dece		
	2002	2001	2000
	(In thousands, except		
Statement of Operations Data:			
Revenues	$188,326	$210,376	$121,383
Expenses:			
Lease operating expenses	18,212	12,132	9,009
Depreciation, depletion and amortization--natural gas and oil properties	108,998	85,059	47,451
Depreciation and amortization--other	914	398	309
Write-down of natural gas and oil properties(1)	--	--	--
General and administrative	10,984	9,443	7,350
Charges related to Enron bankruptcy(2)	128	3,059	--
Stock appreciation rights expense(3)	--	--	--

Total expenses	139,236	110,091	64,119
Income (loss) from operations	49,090	100,285	57,264
Other income (expense):			
Interest income	1,014	3,574	2,908
Interest expense, net	(762)	(381)	(748
Total other income (expense)	252	3,193	2,160
Income (loss) before income taxes	49,342	103,478	59,424
Income tax expense	17,763	37,252	20,858
Income (loss) before cumulative effect of change in accounting principle	31,579	66,226	38,566
Cumulative effect of change in accounting principle(4)	--	--	--
Net income (loss)	31,579	66,226	38,566
Accrual of dividends on preferred stock	--	--	--
Net income (loss) available to common stockholders	$ 31,579	$ 66,226	$ 38,566
Basic income (loss) per common share(5)(6):			
Income (loss) before cumulative effect of change in accounting principle	$ 1.00	$ 2.45	$ 1.70
Cumulative effect of change in accounting principle(4)	--	--	--
Net income (loss) per common share	$ 1.00	$ 2.45	$ 1.70
Diluted income (loss) per common share(5)(6):			
Income (loss) before cumulative effect of change in accounting principle	$ 0.97	$ 2.34	$ 1.61
Cumulative effect of change in accounting principle(4)	--	--	--
Net income (loss) per common share	$ 0.97	$ 2.34	$ 1.61
Weighted average number of common shares outstanding(5)(6):			
Basic	31,695	27,079	22,679
Diluted	32,653	28,360	24,011
Summary Balance Sheet Data:			
Working capital (deficit)	$ (6,359)	$(20,654)	$ 74,005
Property and equipment, net	760,854	522,573	304,381
Total assets	842,715	587,316	442,704
Short-term debt	--	--	--
Accrued preferred dividends payable(6)	--	--	--
Total equity(6)	692,977	458,492	361,259

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(1) At December 31, 1998, the Company recognized a non-cash write-down of natural gas and oil properties in the amount of approximately $2.6 million in connection with the ceiling limitation required by the full cost method of accounting for natural gas and oil properties. The write-down was primarily the result of the decline in natural gas prices experienced in 1998 and through April 9, 1999. As permitted by applicable Commission rules, in calculating the amount of the write-down, the Company used post year-end natural gas and oil price increases of $0.26 per MMBtu of natural

gas and $4.52 per barrel of oil from December 31, 1998 to April 9, 1999. If the Company had used only December 31, 1998 natural gas and oil prices, it would have recognized a total non-cash write-down of natural gas and oil properties of approximately $13.0 million.

(2) The Company had in place both financial hedge and physical contracts with Enron North America Corp. at the time Enron Corp. and its subsidiaries filed for bankruptcy in December 2001. Spinnaker did not receive payment for fixed price swap contracts totaling $2.1 million which were intended to hedge December 2001 natural gas sales, and $1.4 million related to November 2001 natural gas production sold to Enron entities. The Company has recorded a net reserve of $3.2 million against these receivables.

(3) Prior to July 1999, the stock option agreements of two of the Company's officers provided that they could elect to have Spinnaker deliver shares equal to the appreciation in the value of the stock over the option price in lieu of purchasing the amount of shares under option. Based on management's estimate of the share value of Spinnaker, the Company recorded compensation expense of approximately $1.7 million in 1999 related to the stock appreciation rights of the stock option agreements. In July 1999, these two officers agreed to eliminate the stock appreciation rights feature of their stock option agreements.

(4) The cumulative effect of change in accounting principle represents the adoption of Statement of Position 98-5 "Reporting on the Costs of Start-Up Activities."

(5) Spinnaker was originally formed as a limited liability company, and the Company issued common units and preferred units. In connection with its conversion to a corporation in January 1998, the Company exchanged Common Stock for all then outstanding common units and Preferred Stock for all then outstanding preferred units. The Company expresses all historical unit data in shares of Common Stock.

(6) On April 3, 2002, the Company completed a public offering of 5,750,000 shares of Common Stock. On August 16, 2000, the Company completed a public offering of 5,600,000 shares of Common Stock. In connection with its initial public offering in 1999, the Company issued 8,000,000 shares of Common Stock, converted all then outstanding shares of Preferred Stock into 6,061,840 shares of Common Stock and issued 1,200,248 shares of Common Stock to certain holders of the previously outstanding Preferred Stock in lieu of payment of accrued cash dividends.

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

Overview

Financial and operating results in 2002 compared to 2001 included:

- Revenues of $188.3 million, down 10%.
- Income from operations of $49.1 million, down 51%.
- Net income of $31.6 million, or $0.97 per diluted share, down 52%.
- Production of 51.4 Bcfe, down 3%.
- Proved reserves of 323.6 Bcfe, reserve replacement was 101% of production in 2002.

Spinnaker's results of operations and financial position were significantly impacted by lower commodity prices and production in 2002. Of the $22.1 million net decrease in revenues, $29.4 million was due to a lower average commodity price on an equivalent basis and $6.9 million related to decreased production, offset in part by an increase in net hedging income of $14.2 million. The Company had $32.5 million in cash and cash equivalents and no debt at

December 31, 2002.

Risk Factors

In addition to the other information set forth elsewhere in this annual report, the following factors should be carefully considered when evaluating Spinnaker.

Exploration is a high-risk activity, and the 3-D seismic data and other advanced technologies the Company uses cannot eliminate exploration risk and require experienced technical personnel whom the Company may be unable to attract or retain.

The Company's future success will depend on the success of its exploratory drilling program. Exploration activities involve numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be discovered. In addition, the Company often is uncertain as to the future cost or timing of drilling, completing and producing wells. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of the additional exploration time and expense associated with a variety of factors, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions, compliance with governmental requirements and shortages or delays in the availability of drilling rigs or equipment.

Even when used and properly interpreted, 3-D seismic data and visualization techniques only assist geoscientists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know conclusively if hydrocarbons are present or economically producible. The Company could incur losses as a result of expenditures on unsuccessful wells. Poor results from exploration activities could materially and adversely affect future cash flows and results of operations.

The Company's exploratory drilling success will depend, in part, on its ability to attract and retain experienced explorationists and other professional personnel. Competition for explorationists and engineers with experience in the Gulf of Mexico is extremely intense. If the Company cannot retain its current personnel or attract additional experienced personnel, its ability to compete in the Gulf of Mexico could be adversely affected.

A substantial portion of Spinnaker's proved reserves are associated with its deepwater oil discovery at Front Runner. The development of Front Runner will require significant financial resources before initial production and remains subject to other uncertainties that could have a material impact on the development of this discovery.

Spinnaker's deepwater oil discovery at Front Runner, in which the Company has a 25% non-operator working interest, has required and will continue to require significant financial resources in advance of the expected initial production date in the summer of 2004. The Company has incurred $70.2 million in capital expenditures for Front Runner through December 31, 2002 and expects to incur an aggregate of approximately $67.0 million in future development costs during 2003 and 2004. Because another oil and gas exploration and production company operates Front Runner, the Company has a limited ability to influence the operations and costs associated with this property.

Front Runner is located in approximately 3,500 feet of water and wells have been drilled in the Front Runner area to total depths in excess of 20,000 feet.

The Company has limited experience with large deepwater and deep drilling depth discoveries similar to Front Runner as most of its prior discoveries have occurred in shallower waters and at shallower drilling depths. As a result of these uncertainties and risks, the Company may encounter difficulties and delays that could cause actual expenditures to exceed anticipated amounts.

J. Ray McDermott Inc. ("McDermott"), the contractor responsible for construction, delivery and installation of the Front Runner spar production facility, has announced that it is experiencing liquidity concerns. If McDermott experiences additional significant unanticipated costs in the future, it may be unable to fund all of its

anticipated operating and capital needs, which may delay the expected delivery date of the spar production facility as well as the initial production date and actual expenditures may exceed anticipated amounts.

The hull of the spar production facility is being constructed in Dubai, U.A.E. Due to the current military conflict in the Middle East, the delivery date of the hull to the Gulf of Mexico may be delayed. Additionally, weather and other conditions may delay the installation of the spar production facility on location. Any delays in the delivery or installation dates would cause a delay in the initial production date.

Front Runner accounted for more than 60% of Spinnaker's proved undeveloped reserves at December 31, 2002. If the actual reserves associated with Front Runner are substantially less than the estimated reserves, the Company's results of operations and financial condition could be adversely affected.

When production ultimately commences for this discovery, it may produce substantially less oil and natural gas than currently projected. Additionally, the Company cannot predict commodity prices when production commences. If production is substantially less than currently projected or commodity prices are low, the Company's results of operations and financial condition could be adversely affected.

These uncertainties and other risks described in this "Risk Factors" section and elsewhere in this annual report make it difficult to predict whether Front Runner can be successfully or economically developed. If Front Runner cannot be successfully and economically developed, the Company's future business, financial condition and operating results will be materially and adversely affected.

The natural gas and oil business involves many operating risks that can cause substantial losses.

The natural gas and oil business involves a variety of operating risks, including fires, explosions, blow-outs and surface cratering, uncontrollable flows of underground natural gas, oil and formation water, natural disasters, pipe or cement failures, casing collapses, embedded oilfield drilling and service tools, abnormally pressured formations and environmental hazards such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases. If any of these events occur, the Company could incur substantial losses as a result of injury or loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of the Company's operations and repairs to resume operations. If the Company experiences any of these problems, it could affect well bores, platforms, gathering systems and processing facilities, which could adversely affect its ability to conduct operations.

Offshore operations are also subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, the Company could incur substantial liabilities that could reduce or eliminate the funds available for exploration, development or leasehold acquisitions, or result in loss of equipment and properties.

For some risks, the Company may not obtain insurance if it believes the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect the Company's operations.

Exploration for natural gas and oil at deeper drilling depths and in the deep waters of the Gulf of Mexico involves greater operational and financial risks than exploration at shallower depths and in shallower waters. These risks could result in substantial losses.

The Company explores for natural gas and oil at deeper drilling depths and in the deep waters of the Gulf of Mexico where operations are more difficult and costly than at shallower depths and in shallower waters. Deep depth and deepwater drilling and operations require the application of recently developed technologies that

involve a higher risk of mechanical failure. The Company has experienced and will continue to experience significantly higher drilling costs for its deep depth and deepwater prospects.

At December 31, 2002, approximately 92% of the Company's proved undeveloped reserves were located in deep water. The deep water lacks the physical and oilfield service infrastructure present in the shallower waters. As a result, deepwater projects require long-term commitments of significant financial resources. Deepwater operations may also require a significant amount of time between the discovery date and the initial production date when the Company can market the natural gas or oil, increasing both the financial and operational risk involved with these operations.

The Company is vulnerable to operational, regulatory and other risks associated with the Gulf of Mexico because it currently explores and produces exclusively in that area.

The Company's operations and revenues are impacted acutely by conditions in the Gulf of Mexico because it currently explores and produces exclusively in that area. This concentration of activity makes the Company more vulnerable than many of its competitors to the risks associated with the Gulf of Mexico, including delays and increased costs relating to adverse weather conditions, drilling rig and other oilfield services and compliance with environmental and other laws and regulations.

A significant part of the value of the Company's production and reserves is concentrated in a small number of offshore properties. Because of this concentration, any production problems or inaccuracies in reserve estimates related to those properties are more likely to adversely impact the Company's business.

During 2002, approximately 44% of the Company's production came from three of its properties in the Gulf of Mexico. If mechanical problems, storms or other events curtailed a substantial portion of this production, the Company's cash flow would be adversely affected. In addition, at December 31, 2002, the Company's proved reserves were located on 26 different blocks in the Gulf of Mexico, with approximately 73% of the proved reserves attributable to six of these properties. One property, Front Runner, accounted for more than 60% of total proved undeveloped reserves and more than 40% of total proved reserves. If the actual reserves associated with any one of these six properties are substantially less than the estimated reserves, the Company's results of operations and financial condition could be adversely affected.

The Commission is currently reviewing information from Spinnaker and other oil and gas companies operating in the Gulf of Mexico to assess how the industry is determining proved reserves related to new discoveries. Rules and regulations of the Commission allow companies to recognize proved reserves if economic producibility is supported by either actual production or a conclusive formation test. The Commission believes that a production flow test of reserves satisfies the requirements of a conclusive formation test. In the absence of a production flow test, compelling technical data must exist to recognize proved reserves. The industry has increasingly depended on advanced technical testing to support economic producibility. Spinnaker has recorded most of its proved reserves in deep water based on various advanced technical tests rather than production flow tests. The Company expects initial production from the majority of its proved undeveloped reserves in deep water to commence no later than the summer of 2004. The Company believes these proved reserves are properly recorded and classified. Spinnaker has furnished the information requested by the Commission and is unable to predict the outcome of the Commission's review of Spinnaker's and the industry's practices.

If any seismic contractor terminates its data agreement with Spinnaker, the Company's ability to find additional reserves could be impaired.

The Company's success depends heavily on its access to 3-D seismic data. If any seismic contractor terminates its data agreement with Spinnaker, the Company would lose access to a portion of its 3-D seismic

data, which loss could have an adverse effect on its ability to find additional reserves. A seismic contractor may terminate its data agreement with Spinnaker on several grounds, including if a competitor of the seismic contractor acquires control of Spinnaker or if the Company breaches the data agreement with that seismic contractor, subject to certain exceptions. See "Item 1. Business--Seismic Data Agreements--Termination Events" for a description of these exceptions.

Competitors may use superior technology which the Company may be unable to afford or which would require costly investments in order to compete.

The industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, the Company may be placed at a competitive disadvantage, and competitive pressures may force it to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Company can. The Company cannot be certain that it will be able to implement technologies on a timely basis or at a cost that is acceptable to it. One or more of the technologies that the Company currently uses or that it may implement in the future may become obsolete, which may adversely affect the Company's results of operations and financial condition. For example, marine seismic acquisition technology has undergone rapid technological advancements in recent years and further significant technological developments could substantially impair the value of Spinnaker's 3-D seismic data.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or their underlying assumptions will materially affect the quantities and net present value of the Company's reserves.

The process of estimating natural gas and oil reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and net present value of reserves. See "Item 2. Properties--Natural Gas and Oil Reserves."

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

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from the Company's estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, the Company may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond the Company's control. Moreover, some of the producing wells included in the reserve report had produced for only a relatively short period of time as of December 31, 2002. Because most of the reserve estimates are not based on a lengthy production history and are calculated using volumetric analysis, these estimates are less reliable than estimates based on a lengthy production history.

It should not be assumed that the present value of future net cash flows from the Company's proved reserves is the current market value of its estimated natural gas and oil reserves. In accordance with Commission requirements, the Company bases the estimated discounted future net cash flows from its proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the net present value estimate.

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

The Company's future natural gas and oil production depends on its success in finding or acquiring additional reserves. If the Company fails to replace reserves, its level of production and cash flows would be adversely impacted. In general, production from natural gas and oil properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics and mechanical issues. The Company's total proved reserves decline as reserves are produced unless it conducts other successful exploration and development activities or acquires properties containing proved reserves, or both. The Company's ability to make the necessary capital investment to maintain or expand its asset base of natural gas and oil reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. The Company may not be successful in exploring for, developing or acquiring additional reserves. If the Company is not successful, its future production and revenues will be adversely affected.

Relatively short production periods for Gulf of Mexico properties subject the Company to higher reserve replacement needs, require the Company to incur capital expenditures more frequently to replace production and may impair its ability to slow or shut-in production during periods of low prices for natural gas and oil.

Reservoirs in the Gulf of Mexico are generally sandstone reservoirs characterized by high porosity, permeability, pressure and temperature. Production of these reservoirs is generally constant for a relatively shorter period of time with a rapid decline in production at the end of the reservoir life compared to production of reservoirs in many other producing regions of the world. As a result, reserve replacement needs from new prospects in the Gulf of Mexico are greater and require the Company to incur capital expenditures more frequently to replace production than would typically be required in many other producing regions of the world. The Company expects a decline in production during the first quarter of 2003 due to the rapid production decline of certain producing wells and a shut-in for pipeline repairs.

Also, revenues and return on capital will depend significantly on prices prevailing during these relatively short production periods. The Company's potential need to generate revenues to fund ongoing capital commitments or reduce future indebtedness may limit its ability to slow or shut-in production from producing wells in the future during periods of low prices for natural gas and oil.

Natural gas and oil prices fluctuate widely, and low prices could have a material adverse impact on the Company's business and financial results.

The Company's revenues, profitability and future growth depend substantially on prevailing prices for natural gas and oil. Prices also affect the amount of cash flow available for capital expenditures and the Company's ability to borrow and raise additional capital. The amount the Company can borrow under the Credit Facility is subject to periodic re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of natural gas and oil that the Company can economically produce.

Prices for natural gas and oil fluctuate widely. Among the factors that can cause this fluctuation are the level of consumer product demand, weather conditions, domestic and foreign governmental regulations, the price and availability of alternative fuels, political conditions in natural gas and oil producing regions, the domestic and foreign supply of natural gas and oil, the price of foreign imports and overall economic conditions. If natural gas and oil prices decline, even if for only a short period of time, it is possible that write-downs of natural gas and oil properties could occur in the future.

Hedging production has limited and may continue to limit potential gains from increases in commodity prices or result in losses.

The Company enters into hedging arrangements from time to time to reduce its exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. These financial arrangements take the form of swap contracts or cashless collars and are placed with major trading counterparties the Company believes represent minimum credit risks. The Company cannot provide assurance that these trading counterparties will not

become credit risks in the future. Hedging arrangements expose the Company to risks in some circumstances, including situations when the other party to the hedging contract defaults on its contract obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. These hedging arrangements have limited and may continue to limit the benefit the Company could receive from increases in the prices for natural gas and oil. The Company cannot provide assurance that the hedging transactions it has entered into, or will enter into, will adequately protect it from fluctuations in natural gas and oil prices. The Company may choose not to engage in hedging transactions in the future. As a result, the Company may be adversely affected during periods of declining natural gas and oil prices.

Natural gas prices have fluctuated widely in early 2003. The Company will recognize net hedging losses of $17.7 million in the first quarter of 2003 based on natural gas price settlements. If natural gas prices remain at current levels, Spinnaker will incur significant hedging losses in the remainder of 2003.

The Company's success depends on its Chief Executive Officer and other key personnel, the loss of whom could disrupt business operations.

The Company depends to a large extent on the efforts and continued employment of the Company's President and Chief Executive Officer, Roger L. Jarvis, and other key personnel, including the Company's Vice President--Exploration who will retire in early 2004. If Mr. Jarvis or other key personnel resign or become unable to continue in their present role and if they are not adequately replaced, the Company's business operations could be adversely affected.

The Company is subject to complex laws and regulations, including environmental regulations, that can adversely affect the cost, manner or feasibility of doing business.

Exploration for and development, production and sale of natural gas and oil in the U.S. and especially in the Gulf of Mexico are subject to extensive federal, state and local laws and regulations, including environmental laws and regulations. The Company may be required to make large expenditures to comply with environmental and other governmental regulations. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations and taxation.

Under these laws and regulations, the Company could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. The Company does not believe that full insurance coverage for all potential environmental damages is available at a reasonable cost. Failure to comply with these laws and regulations also may result in the suspension or termination of its operations and subject the Company to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that substantially increase costs. For example, Congress or the MMS could decide to limit exploratory drilling or natural gas production in additional areas of the Gulf of Mexico. Accordingly, any of these liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect the Company's financial condition and results of operations.

Competition in the industry is intense, and the Company is smaller and has a more limited operating history than most of its competitors in the Gulf of Mexico.

The Company competes with major and independent natural gas and oil companies for property acquisitions. It also competes for the equipment and labor required to operate and develop properties. Most of the competitors have substantially greater financial and other resources than the Company. As a result, in the deep water where exploration is more expensive, competitors may be better able to withstand sustained periods of unsuccessful drilling. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than the Company can, which would adversely affect its competitive position. These competitors may be able to pay more for exploratory prospects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than the Company can. The Company's ability to explore for natural gas and oil

prospects and to acquire additional properties in the future will depend on its ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, most of the competitors have been operating in the Gulf of Mexico for a much longer time than the Company has and have demonstrated the ability to operate through industry cycles.

The Company cannot control the activities on properties it does not operate.

Other companies operate some of the properties in which the Company has an interest, including Front Runner. As a result, the Company has a limited ability to exercise influence over operations for these properties or their associated costs. The Company's dependence on the operator and other working interest owners for these projects and its limited ability to influence operations and associated costs could materially and adversely affect the realization of its targeted returns on capital in drilling or acquisition activities. The success and timing of drilling and development activities on properties operated by others therefore depend upon a number of factors that are outside of the Company's control, including timing and amount of capital expenditures, the operator's expertise and financial resources, approval of other participants in drilling wells and selection of technology.

The Company may have difficulty financing its planned growth.

The Company has experienced and expects to continue to experience substantial capital expenditure and working capital needs, particularly as a result of its drilling program. In the future, the Company expects it will require additional financing, in addition to cash generated from its operations, to fund its planned growth. The Company cannot be certain that additional financing will be available on acceptable terms or at all. In the event additional capital resources are unavailable, the Company may curtail its drilling, development and other activities or be forced to sell some of its assets on an untimely or unfavorable basis.

Warburg owns a significant number of shares of Common Stock, giving it influence in corporate transactions and other matters, and the interests of Warburg could differ from those of other stockholders.

At December 31, 2002, Warburg owned approximately 20% of the outstanding shares of Common Stock. As a result, Warburg is in a position to significantly influence the outcome of matters requiring a stockholder vote, including the election of directors, the adoption of an amendment to the certificate of incorporation or bylaws and the approval of mergers and other significant corporate transactions. Its influence over Spinnaker may delay or prevent a change of control of the Company and may adversely affect the voting and other rights of other stockholders.

Furthermore, conflicts of interest could arise in the future between the Company and Warburg concerning, among other things, potential competitive business activities or business opportunities. Warburg is not restricted from competitive natural gas and oil exploration and production activities or investments. Warburg currently has significant equity interests in other public and private natural gas and oil companies. The interests of Warburg could differ from those of other stockholders.

A portion of the Company's outstanding shares owned by Warburg or other significant stockholders may be sold into the market in the near future. This could cause the market price of the Common Stock to drop significantly, even if the Company's business is doing well.

The market price of the Common Stock could drop due to sales of a large number of shares of Common Stock in the market or the perception that such sales could occur. This could make it more difficult to raise funds through any future offering of Common Stock.

The certificate of incorporation and bylaws contain provisions that could discourage an acquisition or change of control of the Company.

The certificate of incorporation authorizes the board of directors to issue Preferred Stock without stockholder approval. If the board of directors elects to issue Preferred Stock, it could be more difficult for a third

party to acquire control of the Company, even if that change of control might be beneficial to stockholders. In addition, provisions of the certificate of incorporation and bylaws, such as no stockholder action by written consent and limitations on stockholder proposals at meetings of stockholders, could also make it more difficult for a third party to acquire control of the Company.

Terrorist attacks on natural gas and oil production facilities, transportation systems and storage facilities could have a material adverse impact on the Company's business.

Natural gas and oil production facilities, transportation systems and storage facilities could be targets of terrorist attacks. These attacks could have a material adverse impact if certain natural gas and oil infrastructure integral to the Company's operations were destroyed or damaged.

Critical Accounting Policies

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 disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates include depreciation, depletion and amortization ("DD&A") of proved natural gas and oil properties. Natural gas and oil reserve estimates, which are the basis for unit-of-production DD&A and the full cost ceiling test, are inherently imprecise and are expected to change as future information becomes available. In addition, alternatives may exist among various accounting methods. In such cases, the choice of accounting method may also have a significant impact on reported amounts. The Company's critical accounting policies are as follows:

Full Cost Method of Accounting

The Company uses the full cost method of accounting for its investments in natural gas and oil properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for and developing natural gas and oil are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including those in progress, geological and geophysical service costs and depreciation of support equipment used in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of natural gas and oil properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of natural gas and oil. Application of the full cost method of accounting for oil and gas properties generally results in higher capitalized costs, no exploration costs and higher DD&A rates than the application of the successful efforts method of accounting.

DD&A

The Company computes the provision for DD&A of natural gas and oil properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the amortization base until the properties associated with these costs are evaluated. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values.

Certain future development costs may be excluded from amortization when incurred in connection with major development projects expected to entail significant costs to ascertain the quantities of proved reserves

attributable to the properties under development. The amounts that may be excluded are portions of the costs that relate to the major development project and have not previously been included in the amortization base and the estimated future expenditures associated with the development project. Such costs may be excluded from costs to be amortized until the earlier determination of whether additional reserves are proved or impairment occurs.

As of December 31, 2002, the Company excluded from the amortization base estimated future expenditures of $29.4 million associated with common development costs for its deepwater discovery at Front Runner. This estimate of future expenditures associated with common development costs is based on existing proved reserves to total proved reserves expected to be established upon completion of the Front Runner project.

If the $29.4 million had been included in the amortization base as of December 31, 2002, and no additional reserves were assigned to the Front Runner project, the DD&A rate in 2002 would have been $2.21 per Mcfe, or an increase of $0.09 over the actual DD&A rate of $2.12 per Mcfe. All future development costs associated with the deepwater discovery at Front Runner are included in the determination of estimated future net cash flows from proved natural gas and oil reserves used in the full cost ceiling calculation, as discussed below.

Full Cost Ceiling

Capitalized costs of natural gas and oil properties, net of accumulated DD&A and related deferred taxes, are limited to the estimated future net cash flows from proved natural gas and oil reserves, including the effects of hedging activities in place as of December 31, 2002, discounted at 10%, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (full cost ceiling). If capitalized costs of the full cost pool exceed the ceiling limitation, the excess is charged to expense.

As of December 31, 2002, the Company's full cost ceiling, including estimated future net cash flows calculated using commodity prices of $4.91 per Mcf of natural gas and $30.50 per barrel of oil and condensate, exceeded capitalized costs of natural gas and oil properties, net of accumulated DD&A and related deferred taxes, by approximately $139.9 million. Considering the volatility of natural gas and oil prices, it is probable that the Company's estimate of discounted future net cash flows from proved natural gas and oil reserves will change in the near term. If natural gas or oil prices decline, even if for only a short period of time, or if the Company has downward revisions to its estimated proved reserves, it is possible that write-downs of natural gas and oil properties could occur in the future.

Capitalized Employee and Other General and Administrative Costs

Under the full cost method of accounting, certain costs are capitalized that are directly identified with acquisition, exploration and development activities. These capitalized costs include salaries, employee benefits, costs of consulting services and other related costs and do not include costs related to production, general corporate overhead or similar activities. Spinnaker capitalized employee and other general and administrative costs of $5.9 million, $5.1 million and $3.8 million in 2002, 2001 and 2000, respectively.

Unproved Properties

The costs associated with unproved properties and properties under development are not initially included in the amortization base and relate to unevaluated leasehold acreage and delay rentals, seismic data, wells in-progress and wells pending determination. Unevaluated leasehold costs and delay rentals are either transferred to the amortization base with the costs of drilling the related well or are assessed quarterly for possible impairment or reduction in value. Unevaluated leasehold costs and delay rentals are transferred to the amortization base if a reduction in value has occurred. The costs of seismic data are transferred to the amortization base using the sum-of-the-year's-digits method over a period of six years. The costs associated with wells in-progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. The costs of drilling exploratory dry holes and associated

leasehold costs are included in the amortization base immediately upon determination that the well is unsuccessful.

Natural Gas and Oil Reserves

The process of estimating natural gas and oil reserves is complex. It requires various assumptions, including natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The Company must project production rates and timing of development expenditures. The Company analyzes available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. Therefore, estimates of natural gas and oil reserves are inherently imprecise.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, the Company may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond the Company's control. At December 31, 2002, approximately 82% of the Company's proved reserves were either undeveloped or non-producing. Because most of the reserve estimates are not based on a lengthy production history and are calculated using volumetric analysis, these estimates are less reliable than estimates based on a lengthy production history.

At December 31, 2002, approximately 70% of the Company's proved reserves were undeveloped and primarily related to Front Runner. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. The reserve data assumes that the Company will make these expenditures. Although the Company estimates its reserves and the costs associated with developing them in accordance with industry standards, the estimated costs may be inaccurate, development may not occur as scheduled and results may not be as estimated.

Other Property and Equipment

The costs associated with seismic hardware and software are included in other property and equipment. These costs are amortized into the full cost pool using the straight-line method over three years. Amortization was $1.5 million, $0.5 million and $1.2 million in 2002, 2001 and 2000, respectively.

Commodity Price Risk Management Activities

On January 1, 2001, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 133, as amended, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 established accounting and reporting standards requiring that all derivative instruments be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in a derivative's fair value be realized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset related results on the hedged items in the statement of operations and requires a company to formally document, designate and assess the effectiveness of transactions that qualify for hedge accounting. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Stock-Based Compensation

SFAS No. 148, "Accounting for Stock-Based Compensation--Transition and Disclosure," amends SFAS No. 123 to provide alternative methods of transition for an entity that voluntarily changes to the fair value based method of accounting for stock-based employee compensation and to require prominent disclosure about the effects on reported net income of an entity's accounting policy decisions with respect to stock-based employee compensation. SFAS No. 148 amends Accounting Principles Board ("APB") Opinion No. 28, "Interim Financial Reporting," to require disclosure about those effects in interim financial information.

SFAS No. 123, "Accounting for Stock-Based Compensation," encourages, but does not require, companies to record compensation cost for stock-based employee compensation plans at fair value. The Company has chosen to account for stock-based compensation using the intrinsic value method prescribed in APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the fair value of the Common Stock at the date of the grant over the amount an employee must pay to acquire the Common Stock.

Related Parties

The Company purchases oilfield goods, equipment and services from Baker Hughes Incorporated ("Baker Hughes"), Cooper Cameron Corporation ("Cooper Cameron") and other oilfield services companies in the ordinary course of business. The Company incurred charges of approximately $16.1 million and $16.3 million in 2002 and 2001, respectively, from affiliates of Baker Hughes, of which Mr. Michael E. Wiley, a director of Spinnaker since March 2001, serves as Chairman of the Board, Chief Executive Officer and President. The Company incurred charges of approximately $0.1 million, $0.1 million and $0.5 million in 2002, 2001 and 2000, respectively, from Cooper Cameron, of which Mr. Sheldon R. Erikson, a director of Spinnaker, serves as Chairman of the Board, Chief Executive Officer and President. Spinnaker believes that these transactions are at arm's-length and the charges it pays for such goods, equipment and services are competitive with the charges and fees of other companies providing oilfield goods, equipment and services to the oil and gas exploration and production industry. Both of these companies are leaders in their respective segments of the oilfield services sector. The Company could be at a disadvantage if it were to discontinue using either company as vendors.

Results of Operations

The following table sets forth certain operating information with respect to the natural gas and oil operations of the Company:

	Year Ended December 31,		
	2002	2001	2000
Production:			
Natural gas (MMcf)	45,180	51,234	28,845
Oil and condensate (MBbls)	1,040	310	225
Total (MMcfe)	51,419	53,094	30,194
Revenues (in thousands):			
Natural gas	$156,214	$212,238	$133,264
Oil and condensate	27,448	7,718	6,775
Net hedging income (loss)	4,664	(9,580)	(18,656)
Total	$188,326	$210,376	$121,383

Average sales price per unit:			
Natural gas revenues from production (per Mcf)	$ 3.46	$ 4.14	$ 4.62
Effects of hedging activities (per Mcf)	0.10	(0.18)	(0.59)
Average price (per Mcf)	$ 3.56	$ 3.96	$ 4.03
Oil and condensate revenues from production (per Bbl)	$ 26.39	$ 24.90	$ 30.14
Effects of hedging activities (per Bbl)	--	--	(7.16)
Average price (per Bbl)	$ 26.39	$ 24.90	$ 22.98
Total revenues from production (per Mcfe)	$ 3.57	$ 4.14	$ 4.64
Effects of hedging activities (per Mcfe)	0.09	(0.18)	(0.62)
Total average price (per Mcfe)	$ 3.66	$ 3.96	$ 4.02
Expenses (per Mcfe):			
Lease operating expenses	$ 0.35	$ 0.23	$ 0.30
Depreciation, depletion and amortization--natural gas and oil properties	$ 2.12	$ 1.60	$ 1.57
Income from operations (in thousands)	$ 49,090	$100,285	$ 57,264

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

Revenues, including the effects of hedging activities, decreased $22.1 million in 2002 compared to 2001. Natural gas revenues decreased $56.0 million, oil and condensate revenues increased $19.7 million and revenues from natural gas hedging activities improved $14.2 million in 2002 compared to 2001.

Production decreased approximately 1.7 Bcfe in 2002 compared to 2001. Average daily production in 2002 was 141 MMcfe compared to 145 MMcfe in 2001. Natural gas revenues decreased $56.0 million due to lower volumes of 6.1 Bcf and a lower average price in 2002 compared to 2001. The production declines of certain producing wells, particularly in the High Island 202 area, resulted in lower natural gas production in 2002. Oil and condensate revenues increased $19.7 million primarily due to higher production volumes of 730 MBbls. The Company expects a decline in production during the first quarter of 2003 due to the rapid production decline of certain producing wells and shut-ins for pipeline repairs.

Lease operating expenses increased $6.1 million in 2002 compared to 2001. Of the total increase in lease operating expenses, approximately $7.3 million was attributable to wells on ten new blocks that commenced production in 2002, offset in part by a decrease of $0.9 million in operating expenses associated with existing wells and a decrease of $0.3 million in workovers. The overall increase in the lease operating expense rate per Mcfe in 2002 compared to 2001 was primarily due to the production declines of certain wells in the High Island 202 area where the lease operating rate in 2001 was significantly lower compared to other producing areas operated by the Company. Additionally, the Company is experiencing higher lease operating rates associated with new wells compared to historical average lease operating rates due to well locations, transportation and gathering agreements and processing requirements.

DD&A increased $23.9 million in 2002 compared to 2001. Of the total increase in DD&A, $26.6 million related to an increase in the DD&A rate, offset in part by $2.7 million related to lower production volumes of 1.7 Bcfe in 2002 compared to 2001. The increase in the DD&A rate in 2002 was primarily due to costs of $72.6 million associated with 12 unsuccessful wells and higher finding costs associated with new discoveries in 2002.

General and administrative expenses increased $1.5 million in 2002 compared to 2001. The increase in general and administrative expenses was primarily due to higher employment-related costs resulting from the Company's recent growth and increased professional services fees.

Interest income decreased $2.6 million in 2002 compared to 2001 primarily due to lower average cash and short-term investment balances and significantly lower interest rates in 2002. Interest expense increased $0.3 million in 2002 compared to 2001 primarily due to interest on borrowings of $37.0 million in the first quarter of 2002 and higher commitment fees. On April 3, 2002, the Company repaid all of its outstanding borrowings of $37.0 million under the Credit Facility.

Income tax expense decreased $19.5 million in 2002 compared to 2001 due to lower earnings in 2002. Income taxes were accrued at a 36% effective tax rate in 2002 and 2001.

The Company recognized net income of $31.6 million, or $1.00 per basic share and $0.97 per diluted share, in 2002 compared to net income of $66.2 million, or $2.45 per basic share and $2.34 per diluted share, in 2001.

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

Revenues increased $89.0 million in 2001 compared to 2000. Excluding the effects of hedging activities, natural gas revenues increased $79.0 million and oil and condensate revenues increased $0.9 million. Losses resulting from hedging activities decreased by $9.1 million in 2001 compared to 2000, thereby improving revenues.

Production increased approximately 22.9 Bcfe in 2001 compared to 2000. Average daily production in 2001 was 145 MMcfe compared to 82 MMcfe in 2000. Natural gas production volumes increased 22.4 Bcf,

contributing $123.9 million of the increase in natural gas revenues, excluding the effects of hedging activities, offset in part by $44.9 million related to lower average natural gas prices in 2001 compared to 2000. Oil and condensate production volumes increased 85 MBbls, contributing $2.8 million of the increase in oil and condensate revenues, offset in part by $1.9 million related to decreases in average oil and condensate prices. The rapid production declines of certain producing wells, combined with pipeline-mandated curtailments of certain facilities, shut-ins related to facility upgrades and less than anticipated results from workovers resulted in lower production in the fourth quarter of 2001 compared to the prior quarter.

Lease operating expenses increased $3.1 million in 2001 compared to 2000. Of the total increase in lease operating expenses, $1.0 million was primarily related to workover activities in 2001 and $0.4 million was attributable to wells on new blocks that commenced production subsequent to December 31, 2000. The lease operating expense rate decreased 23% to $0.23 per Mcfe in 2001 compared to 2000 primarily due to increased production coupled with continued efficiencies gained in core operating areas, including the High Island 202 area.

DD&A increased $37.7 million in 2001 compared to 2000. The change in DD&A was attributable to an increase in production of 22.9 Bcfe and a slightly higher DD&A rate, which impacted DD&A by $36.0 million and $1.7 million, respectively.

General and administrative expenses increased $2.1 million in 2001 compared to 2000. The increase in general and administrative expenses was primarily due to higher employment-related costs resulting from the Company's recent growth.

The Company had in place both financial hedge and physical contracts with Enron North America Corp. at the time Enron Corp. and its subsidiaries filed for bankruptcy in December 2001. Spinnaker did not receive payment for fixed price swap contracts totaling $2.1 million which were intended to hedge December 2001 natural gas sales, and $1.4 million related to November 2001 natural gas production sold to Enron entities. The Company has recorded a net reserve of $3.2 million related to these receivables.

Interest income increased $0.7 million in 2001 compared to 2000 primarily due to investment income associated with proceeds from the Company's public offering of Common Stock completed on August 16, 2000. Interest expense decreased $0.4 million in 2001 compared to 2000. The Company had no outstanding borrowings in 2001 compared to 2000.

Income tax expense increased $16.4 million in 2001 compared to 2000 and primarily relates to deferred income taxes accrued at a 36% effective tax rate in 2001 and a 35% effective tax rate in 2000.

The Company recognized net income of $66.2 million, or $2.45 per basic share and $2.34 per diluted share, in 2001 compared to net income of $38.6 million, or $1.70 per basic share and $1.61 per diluted share, in 2000.

Liquidity and Capital Resources

The Company has experienced and expects to continue to experience substantial capital requirements, primarily due to its active exploration and development programs in the Gulf of Mexico. Spinnaker has capital expenditure plans for 2003 totaling approximately $250.0 million. Spinnaker has participated in a significant deepwater oil discovery, Front Runner, with a 25% non-operator working interest. Spinnaker incurred capital expenditures associated with Front Runner of $40.8 million in 2002 and $70.2 million from inception through December 31, 2002. The Company expects to incur approximately $86.0 million in future development costs related to Front Runner, including approximately $46.0 million in 2003, $21.0 million in 2004 and $19.0 million thereafter.

Natural gas and oil prices have a significant impact on the Company's cash flows available for capital expenditures and its ability to borrow and raise additional capital. The amount the Company can borrow under its

Credit Facility is subject to periodic re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of natural gas and oil that the Company can economically produce. Additionally, the rapid production declines of certain producing wells resulted in lower production in 2002. The Company expects a decline in production during the first quarter of 2003 from the 16.3 Bcfe reported in the fourth quarter of 2002 due to the rapid production decline of certain producing wells and shut-ins for pipeline repairs. Lower prices and/or lower production may decrease revenues, cash flows and the borrowing base under the Credit Facility, thus reducing the amount of financial resources available to meet the Company's capital requirements. The Company believes that working capital, cash flows from operations and proceeds from available borrowings under its Credit Facility will be sufficient to meet its capital requirements in the next twelve months. However, additional debt or equity financing may be required in the future to fund growth and exploration and development programs. In the event additional capital resources are unavailable, the Company may curtail its drilling, development and other activities or be forced to sell some of its assets on an untimely or unfavorable basis.

On April 3, 2002, the Company completed a public offering of 5,750,000 shares of Common Stock at $41.50 per share, including the over-allotment option consisting of 750,000 shares. After payment of underwriting discounts and commissions, the Company received net proceeds of $227.9 million. On April 3, 2002, the Company used a portion of the proceeds from the offering to repay outstanding borrowings of $37.0 million. The remaining net proceeds were invested in short-term high quality investments and are being used to fund a portion of the costs to develop the Company's deepwater oil discovery at Front Runner, to fund a portion of exploration and other development activities and for general corporate purposes, including possible acquisitions of properties or seismic data.

Spinnaker has an effective shelf registration statement relating to the potential public offer and sale by the Company or certain of its affiliates of up to $500.0 million of any combination of debt securities, preferred stock, common stock, warrants, stock purchase contracts and trust preferred securities from time to time or when financing needs arise. The registration statement does not provide assurance that the Company will or could sell any such securities.

Cash and cash equivalents increased $18.5 million to $32.5 million at December 31, 2002. The components of the increase in cash and cash equivalents include $154.0 million provided by operating activities, $363.8 million used in investing activities and $228.3 million provided by financing activities.

Operating Activities

Net cash provided by operating activities in 2002 decreased 26% to $154.0 million primarily due to lower commodity prices and production. Cash flow from operations is dependent upon the Company's ability to increase production through its exploration and development programs and the prices of natural gas and oil. The Company has made significant investments to expand its operations in the Gulf of Mexico. These investments increased the Company's average daily production in the fourth quarter of 2002 as compared to prior quarters; however, the Company expects a decline in production during the first quarter of 2003 from the 16.3 Bcfe reported in the fourth quarter of 2002.

The Company sells its natural gas and oil production under fixed or floating market price contracts. Spinnaker enters into hedging arrangements from time to time to reduce its exposure to fluctuations in natural gas and oil prices and achieve more predictable cash flow. However, these contracts also limit the benefits the Company would realize if prices increase. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

The Company's cash flow from operations also depends on its ability to manage working capital, including accounts receivable, accounts payable and accrued liabilities. The net increase of $13.4 million in accounts receivable was primarily related to an increase in the natural gas and oil revenue accrual due to higher production and commodity prices in December 2002 compared to December 2001. The net decrease of $15.1 million in

accounts payable and accrued liabilities was primarily due to the reversal of current deferred taxes of $7.2 million related to the fair value of open derivative contracts at December 31, 2001. In connection with the fair value of open derivative contracts at December 31, 2002, the Company recorded a net deferred tax asset of $7.2 million in other current assets.

Investing Activities

Net cash used in investing activities in 2002 increased 37% to $363.8 million compared to 2001. Net oil and gas property capital expenditures were $356.6 million and other property and equipment capital expenditures were $7.2 million.

As part of its strategy, the Company explores for natural gas and oil at deeper drilling depths and in the deep waters of the Gulf of Mexico, where operations are more difficult and costly than at shallower drilling depths and in shallower waters. Along with higher risks and costs associated with these areas, greater opportunity exists for reserve additions. The Company has experienced and will continue to experience significantly higher drilling costs for its deep shelf and deepwater projects relative to the drilling costs on shallower depth shelf projects in the Gulf of Mexico. The Company drilled 26 wells in 2002, 14 of which were successful. In 2001, the Company drilled 35 wells, 19 of which were successful. Since inception and through December 31, 2002, the Company has drilled 120 wells, 70 of which were successful, representing a success rate of 58%. Dry hole costs, including associated leasehold costs, were $72.6 million in 2002.

Purchases of other property and equipment increased to $7.2 million in 2002 primarily due to expenditures for seismic hardware and software of $4.1 million, leasehold improvements of $1.4 million and other hardware and software upgrades and other equipment of $1.7 million.

The Company has capital expenditure plans for 2003 totaling approximately $250.0 million, primarily for costs related to exploration and development programs. The Company does not anticipate any significant abandonment or dismantlement costs in 2003. Actual levels of capital expenditures may vary due to many factors, including drilling results, natural gas and oil prices, the availability of capital, industry conditions, acquisitions, decisions of operators and other prospect owners and the prices of drilling rig dayrates and other oilfield goods and services. In 2002, the Company incurred acquisition, exploration and development costs of $39.8 million, $163.3 million and $139.4 million, respectively. The costs associated with unproved properties and properties under development not included in the amortization base were $141.3 million and $102.9 million as of December 31, 2002 and 2001, respectively, and included the following (in thousands):

	As of December 31,	
	2002	2001
Leasehold, delay rentals and seismic data	$122,409	$ 92,150
Wells in-progress	17,639	10,112
Other	1,278	619
Total	$141,326	$102,881

Financing Activities

Net cash provided by financing activities of $228.3 million in 2002 included proceeds from the public offering of Common Stock and $37.0 million in proceeds from and subsequent payments on borrowings. The Company received net proceeds of $227.9 million from the Common Stock offering on April 3, 2002, and used a portion of the proceeds from the offering to repay outstanding borrowings of $37.0 million.

On December 28, 2001, the Company replaced its $75.0 million credit facility with an unsecured $200.0 million Credit Facility with a group of seven banks. The borrowing base of the three-year Credit Facility is

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re-determined on or about April 30 and September 30 each year. The banks and Spinnaker also have the option to request one additional re-determination each year. The banks determine the borrowing base at their sole discretion and in their usual and customary manner. The amount of the borrowing base is a function of the banks' view of the Company's reserve profile as well as commodity prices. The current borrowing base is $100.0 million. The Company has the option to elect to use a base interest rate as described below or the LIBOR rate plus, for each such rate, a spread based on the percentage of the borrowing base used at that time. The base interest rate under the Credit Facility is a fluctuating rate of interest equal to the higher of either Toronto-Dominion Bank's base rate for dollar advances made in the United States or the Federal Funds Rate plus 0.5% per annum. The commitment fee rate ranges from 0.3% to 0.5%, depending on the borrowing base usage.

The Credit Facility contains various covenants and restrictive provisions, including the following limitations, subject to some exceptions, where the Company:

- may not incur any other indebtedness from borrowings, except for indebtedness arising under hedging agreements, indebtedness incurred in the ordinary course of business not to exceed $1.0 million, unsecured vendor indebtedness of the Company related to purchases of 2-D and 3-D seismic data made in the ordinary course of business in an amount not to exceed $25.0 million, other unsecured indebtedness in an amount not to exceed $10.0 million in the aggregate;

- may not incur any liens upon properties or assets other than permitted liens securing indebtedness of up to $1.0 million, liens on the 2-D and 3-D seismic data securing the indebtedness permitted to acquire such data, pledges or deposits to secure hedging agreements up to $15.0 million, liens on property required as a condition to enter into a synthetic lease transaction in the ordinary course of business and other liens in the ordinary course of business;

- may not dispose of any assets or properties except obsolete equipment, inventory sold in the ordinary course of business, reserves in non-proved categories, a second license in certain seismic data, or interests in natural gas and oil properties included in the borrowing base in an aggregate amount not to exceed $25.0 million in any fiscal year;

- may not make or pay any dividend, distribution or payment in respect of capital stock nor purchase, redeem, acquire, retire or permit any reduction or retirement of capital stock in excess of $10.0 million in any fiscal year;

- must maintain the ratio of consolidated current assets to consolidated current liabilities as of the end of each fiscal quarter so that it is not less than 1.00 to 1.00. For purposes of the calculation, availability under the Credit Facility is included as current assets, any payments of principal owing under the Credit Facility required to be repaid within one year from the time of the calculation are excluded from current liabilities and mark-to-market hedging exposure is excluded from both current assets and current liabilities;

- must maintain a tangible net worth so that it is not less than the sum of 80% of the tangible net worth as of September 30, 2001, plus 50% of the adjusted consolidated net income for each fiscal quarter since the closing of the Credit Facility, plus 75% of the proceeds from the sale of any security, including without limitation, common equity, preferred equity or other equity interests or equity securities including warrants, options and the like issued after the closing of the Credit Facility; and

- may not enter into any hedging agreement unless the percent of volumes to be hedged to estimated production volumes for such month from total internally-projected proved reserves does not exceed: 100% for the period one to three months from and after the hedging agreement transaction date, 66 2/3% for the period four to 18 months from and after the hedging agreement transaction date and 33 1/3% for the period 19 to 36 months from and after the hedging agreement transaction date. Additionally, at no time will any hedging agreement of any nature have a counterparty with a minimum long-term senior unsecured indebtedness rating less than "BBB+" by Standard & Poor's or "Baa1" by Moody's Investors Services, Inc. at the time that such counterparty entered into the relevant transaction under such hedging

agreement and at no time will exposure to any single counterparty exceed 25% of the estimated twelve-month production volumes from total proved reserves.

At December 31, 2002, the Company was in compliance with the covenants and restrictive provisions and had no outstanding borrowings under the Credit Facility. The Company expects to borrow under the Credit Facility in 2003 and be in compliance with the covenants and restrictive provisions for the next twelve months.

Contractual Obligations

The Company leases administrative offices, office equipment and oil and gas equipment under non-cancelable operating leases. The Company had no long-term debt, capital lease or purchase obligations or other contractual long-term liabilities as of December 31, 2002. The Company has incurred obligations in the ordinary course of business under purchase and service agreements that are not included in the table below, including obligations of approximately $35.4 million and $6.7 million in 2003 and 2004, respectively, for construction of the Front Runner spar production facility. Operating lease obligations as of December 31, 2002 are as follows (in thousands):

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Operating leases............	$6,032	$1,708	$3,800	$524	$--
Other contractual obligations	--	--	--	--	--

Total	$6,032	$1,708	$3,800	$524	$--

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

The Company is exposed to changes in interest rates. Changes in interest rates affect the interest earned on cash and cash equivalents and the interest rate paid on borrowings under the Credit Facility. The Company does not currently use interest rate derivative instruments to manage exposure to interest rate changes, but may do so in the future.

Commodity Price Risk

The Company's revenues, profitability and future growth depend substantially on prevailing prices for natural gas and oil. Prices also affect the amount of cash flow available for capital expenditures and the Company's ability to borrow and raise additional capital. Lower prices may also reduce the amount of natural gas and oil that the Company can economically produce. The Company sells its natural gas and oil production under fixed or floating market price contracts. Spinnaker enters into hedging arrangements from time to time to reduce its exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. Spinnaker does not enter into such hedging arrangements for trading purposes. However, these contracts also limit the benefits the Company would realize if prices increase. These financial arrangements are fixed price swap contracts and cashless collar arrangements and are placed with major trading counterparties the Company believes represent minimum credit risks. Spinnaker cannot provide assurance that these trading counterparties will not become credit risks in the future. Under its current hedging practice, the Company generally does not hedge more than 66 2/3% of its estimated twelve-month production quantities without the prior approval of the risk management committee of the board of directors.

On January 1, 2001, the Company adopted SFAS No. 133, as amended, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 established accounting and reporting standards requiring that all derivative instruments be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in a derivative's fair value be realized currently in earnings unless

specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset related results on the hedged items in the statement of operations and requires a company to formally document, designate and assess the effectiveness of transactions that qualify for hedge accounting.

The Company enters into New York Mercantile Exchange ("NYMEX") related swap contracts and collar arrangements from time to time. The Company's swap contracts and collar arrangements will settle based on the reported settlement price on the NYMEX for the last trading day of each month for natural gas.

In a swap transaction, the counterparty is required to make a payment to the Company for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. The Company is required to make a payment to the counterparty for the difference between the fixed price and the settlement price if the settlement price is above the fixed price. As of December 31, 2002, Spinnaker's commodity price risk management positions in fixed price natural gas swap contracts and related fair value were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Price (Per MMBtu)	Fair Value (in thousands)
First Quarter 2003.	60,000	$3.71	$ (5,979)
Second Quarter 2003	53,297	3.55	(4,411)
Third Quarter 2003.	50,000	3.55	(4,068)
Fourth Quarter 2003	50,000	3.63	(4,340)
Year 2003..........	53,288	$3.61	$(18,798)

In a collar arrangement, the counterparty is required to make a payment to the Company for the difference between the fixed floor price and the settlement price if the settlement price is below the fixed floor price. The Company is required to make a payment to the counterparty for the difference between the fixed ceiling price and the settlement price if the settlement price is above the fixed ceiling price. Neither party is required to make a payment if the settlement price falls between the fixed floor price and the fixed ceiling price. As of December 31, 2002, Spinnaker's commodity price risk management positions in natural gas collar arrangements and related fair value were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Floor Price (Per MMBtu)	Weighted Average Ceiling Price (Per MMBtu)	Fair Value (in thousands)
First Quarter 2003.	15,000	$3.25	$5.21	$ (228)
Second Quarter 2003	15,000	3.25	5.21	(262)
Third Quarter 2003.	15,000	3.25	5.21	(287)
Fourth Quarter 2003	15,000	3.25	5.21	(342)
Year 2003..........	15,000	$3.25	$5.21	$(1,119)

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The Company reported a net liability of $19.9 million and a net asset of $22.3 million related to its derivative contracts at December 31, 2002 and 2001, respectively. Amounts related to hedging activities as of December 31, 2002 and 2001 were as follows (in thousands):

As of December 31,

	2002	2001
Current assets:		
Hedging asset..	$ --	$20,593
Deferred tax asset related to hedging activities......	7,170	--
Non-current assets:		
Hedging asset..	$ --	$ 1,726
Current liabilities:		
Hedging liability....................................	$ 19,917	$ --
Deferred tax liability related to hedging activities..	--	7,208
Non-current liabilities:		
Deferred tax liability related to hedging activities..	$ --	$ 604
Accumulated other comprehensive income (loss):		
Accumulated other comprehensive income (loss).........	$(19,917)	$22,319
Income taxes...	7,170	(7,812)
Accumulated other comprehensive income (loss).....	$(12,747)	$14,507

The Company recognized a net hedging gain of $4.7 million and net hedging losses of $9.6 million and $18.7 million in revenues in 2002, 2001 and 2000, respectively. There was no ineffective component of the derivatives recognized in earnings in 2002 and 2001. Based on future natural gas prices as of December 31, 2002, the Company would reclassify a net loss of $12.7 million from accumulated other comprehensive income (loss) to earnings within the next twelve months. The amounts ultimately reclassified into earnings will vary due to changes in the fair value of the open derivative contracts prior to settlement.

Subsequent to December 31, 2002, Spinnaker has not entered into additional hedging arrangements. Natural gas prices have fluctuated widely in early 2003. The Company will recognize net hedging losses of $17.7 million in the first quarter of 2003 based on natural gas price settlements. If natural gas prices remain at current levels, Spinnaker will incur significant hedging losses in the remainder of 2003.

To calculate the potential effect of the derivative contracts on future revenues, the Company applied NYMEX natural gas forward prices as of December 31, 2002 to the quantity of the Company's natural gas production covered by those derivative contracts as of that date. The following table shows the estimated potential effects of the derivative financial instruments on future revenues (in thousands):

Derivative Instrument	Estimated Decrease in Revenues at Current Prices	Estimated Decrease in Revenues with 10% Decrease in Prices	Estimated Decrease in Revenues with 10% Increase in Prices
Fixed price swap transactions	$(18,798)	$(10,926)	$(26,912)
Collar arrangements..........	$ (1,119)	$ (289)	$ (2,216)

Item 8. Financial Statements and Supplementary Data

The consolidated financial statements and supplementary data of the Company appear on pages 46 through 71 hereof and are incorporated by reference into this Item 8. Selected quarterly financial data is set forth in Note 13 of the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

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

There have been no disagreements with the Company's accountants or any reportable events regarding accounting principles or practices or financial statement disclosures.

PART III

Item 10. Directors and Executive Officers of the Registrant

The Company's Definitive Proxy Statement for its 2003 Annual Meeting of Stockholders, when filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, will be incorporated by reference into this annual report on Form 10-K pursuant to General Instruction G(3) of Form 10-K and will provide the information required under Part III, Item 10.

Item 11. Executive Compensation

The Company's Definitive Proxy Statement for its 2003 Annual Meeting of Stockholders, when filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, will be incorporated by reference into this annual report on Form 10-K pursuant to General Instruction G(3) of Form 10-K and will provide the information required under Part III, Item 11.

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

The Company's Definitive Proxy Statement for its 2003 Annual Meeting of Stockholders, when filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, will be incorporated by reference into this annual report on Form 10-K pursuant to General Instruction G(3) of Form 10-K and will provide the information required under Part III, Item 12.

At December 31, 2002, officers, directors and employees had been granted options to purchase Common Stock under stock plans adopted in 1998, 1999, 2000 and 2001. The following table provides "Securities Authorized for Issuance Under Equity Compensation Plans":

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Nu sec re avai futur unde comp
Equity compensation plans approved by security holders....	3,954,002	$23.00	1
Equity compensation plans not approved by security holders	432,531	$31.81	
	---------		-

Total...	4,386,533	$23.87	2
	=========		=

The Spinnaker Exploration Company 2000 Stock Option Plan (the "2000 Plan") was adopted by the board of directors of Spinnaker without the approval of the stockholders of the Company in order for Spinnaker to grant options to purchase Common Stock as a material inducement to certain persons who were not previously employed by the Company to enter into an employment contract with the Company. The number of shares of Common Stock that may be issued under the 2000 Plan may not exceed 500,000 shares. The purchase price of any Common Stock pursuant to any options granted under the 2000 Plan may not be less than 80% of the fair market value of the Common Stock on the date the option is granted, subject to certain limited exceptions. The Company has not granted nor does it intend to grant any options under the 2000 Plan at a price below the fair market value of the Common Stock on the date of grant.

Item 13. Certain Relationships and Related Transactions

The Company's Definitive Proxy Statement for its 2003 Annual Meeting of Stockholders, when filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, will be incorporated by reference into this annual report on Form 10-K pursuant to General Instruction G(3) of Form 10-K and will provide the information required under Part III, Item 13.

Item 14. Controls and Procedures

(a) Evaluation of disclosure controls and procedures. Within 90 days before the filing of this annual report on Form 10-K, the Company's principal executive officer and principal financial officer evaluated the effectiveness of the Company's disclosure controls and procedures. Based on the evaluation, the Company's principal executive officer and principal financial officer believe that:

- the Company's disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in the reports it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms; and

- the Company's disclosure controls and procedures were effective to ensure that material information was accumulated and communicated to the Company's management, including the Company's principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

(b) Changes in internal controls. There have been no significant changes in the Company's internal controls or in other factors that could significantly affect the Company's internal controls subsequent to their evaluation, nor have there been any corrective actions with regard to significant deficiencies or material weaknesses.

PART IV

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

(a) Financial Statements

(1) and (2) Financial Statements and Schedules

See "Index to Consolidated Financial Statements" on page 46.

(3) Exhibits

See "Exhibit Index" on page 72.

The management contracts and compensatory plans or arrangements required to be filed as exhibits to this report are as follows:

Exhibit Number	Description
10.2	--Amended and Restated 1998 Spinnaker Stock Option Plan (incorporated by reference to Exh 10.2 to Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
10.6	--Employment Agreement between Spinnaker and Roger L. Jarvis dated December 20, 1996, as amended (incorporated by reference to Exhibit 10.6 to Spinnaker's Registration Statemen Form S-1 (Commission File No. 333-83093))
10.7	--Employment Agreement between Spinnaker and William D. Hubbard dated February 24, 1997, amended (incorporated by reference to Exhibit 10.8 to Spinnaker's Registration Statemen Form S-1 (Commission File No. 333-83093))
10.8	--Employment Agreement between Spinnaker and Kelly M. Barnes dated February 24, 1997, as amended (incorporated by reference to Exhibit 10.9 to Spinnaker's Registration Statemen Form S-1 (Commission File No. 333-83093))
10.9	--1999 Spinnaker Stock Incentive Plan (incorporated by reference to Exhibit 10.10 to Spin Registration Statement on Form S-1 (Commission File No. 333-83093))
10.10	--1999 Spinnaker Employee Stock Purchase Plan (incorporated by reference to Exhibit 10.11 Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
10.12	--Adjunct Stock Option Plan (incorporated by reference to Exhibit 4.3 to Spinnaker's Regi Statement on Form S-8 (Commission File No. 333-36592))
10.13	--Spinnaker Exploration Company 2000 Stock Option Plan (incorporated by reference to Exhi 10.13 to Spinnaker's Annual Report on Form 10-K for the year ended December 31, 2000)
10.14	--Spinnaker Exploration Company 2001 Stock Incentive Plan, as amended (incorporated by reference to Exhibit 10.2 to Spinnaker's Registration Statement on Form S-8 (Commission No. 333-61888))

(b) Reports on Form 8-K

A Current Report on Form 8-K dated November 12, 2002 and filed on November 13, 2002 furnished under "Item 9. Regulation FD Disclosure" the certifications by each of the Chief Executive Officer and the Chief Financial Officer that accompanied the Company's Quarterly Report on Form 10-Q for the period ended September 30, 2002 in accordance with 18 U.S.C. Section 1350. No financial statements were filed therewith.

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.

March 25, 2003

SPINNAKER EXPLORATION COMPANY

By: /s/ ROGER L. JARVIS

Roger L. Jarvis
Chairman, President, Chief Executive Officer and Director

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 in the capacities and on the dates indicated.

Signature	Title	Date
/s/ ROGER L. JARVIS Roger L. Jarvis	Chairman, President, Chief Executive Officer and Director	March 25, 2003
/s/ ROBERT M. SNELL Robert M. Snell	Vice President, Chief Financial Officer and Secretary (Principal Financial Officer)	March 25, 2003
/s/ JEFFREY C. ZARUBA Jeffrey C. Zaruba	Vice President, Treasurer and Assistant Secretary (Principal Accounting Officer)	March 25, 2003
/s/ SHELDON R. ERIKSON Sheldon R. Erikson	Director	March 25, 2003
/s/ JEFFREY A. HARRIS Jeffrey A. Harris	Director	March 25, 2003
/s/ MICHAEL E. MCMAHON Michael E. McMahon	Director	March 25, 2003
/s/ MICHAEL G. MORRIS Michael G. Morris	Director	March 25, 2003
/s/ HOWARD H. NEWMAN Howard H. Newman	Director	March 25, 2003
/s/ MICHAEL E. WILEY	Director	March 25, 2003

Michael E. Wiley

CERTIFICATION OF
PRINCIPAL EXECUTIVE OFFICER
OF SPINNAKER EXPLORATION COMPANY
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT

I, Roger L. Jarvis, certify that:

1. I have reviewed this annual report on Form 10-K of Spinnaker Exploration Company;
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 officers 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 officers 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 officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 25, 2003

/s/ ROGER L. JARVIS

Name: Roger L. Jarvis
Title: Chief Executive Officer

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CERTIFICATION OF
PRINCIPAL FINANCIAL OFFICER
OF SPINNAKER EXPLORATION COMPANY
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT

I, Robert M. Snell, certify that:

1. I have reviewed this annual report on Form 10-K of Spinnaker Exploration Company;
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 officers 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 officers 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 officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls

subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 25, 2003

/s/ ROBERT M. SNELL

Name: Robert M. Snell
Title: Chief Financial Officer

SPINNAKER EXPLORATION COMPANY

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Stockholders of
Spinnaker Exploration Company:

We have audited the accompanying consolidated balance sheets of Spinnaker Exploration Company and subsidiaries, as of December 31, 2002 and 2001, and the related consolidated statements of operations, equity and cash flows for each of the years in the three-year period ended December 31, 2002. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the 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 Spinnaker Exploration Company and subsidiaries as of December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

As explained in Note 2 to the consolidated financial statements, effective January 1, 2001, the Company changed its method of accounting for its derivative instruments.

KPMG LLP

Houston, Texas
February 7, 2003

SPINNAKER EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share data)

	As of Dece
	2002
ASSETS	
CURRENT ASSETS:	
Cash and cash equivalents	$ 32,543
Accounts receivable, net of allowance for doubtful accounts of $3,232 and $3,059 at December 31, 2002 and 2001, respectively	37,572
Hedging assets	--
Other	11,438
Total current assets	81,553
PROPERTY AND EQUIPMENT:	
Oil and gas, on the basis of full-cost accounting:	
Proved properties	879,840
Unproved properties and properties under development, not being amortized	141,326
Other	14,461
	1,035,627
Less--Accumulated depreciation, depletion and amortization	(274,773)
Total property and equipment	760,854
OTHER ASSETS	308
Total assets	$ 842,715
LIABILITIES AND EQUITY	
CURRENT LIABILITIES:	
Accounts payable	$ 29,453

Accrued liabilities and other	38,542
Hedging liabilities	19,917
Total current liabilities	87,912
DEFERRED INCOME TAXES	61,826
COMMITMENTS AND CONTINGENCIES (Note 11)	
EQUITY:	
Preferred stock, $0.01 par value; 10,000,000 shares authorized; no shares issued and outstanding at December 31, 2002 and 2001, respectively	--
Common stock, $0.01 par value; 50,000,000 shares authorized; 33,184,463 shares issued and 33,171,759 shares outstanding at December 31, 2002 and 27,308,912 shares issued and 27,293,264 shares outstanding at December 31, 2001	332
Additional paid-in capital	596,087
Retained earnings	109,337
Less: Treasury stock, at cost, 12,704 and 15,648 shares at December 31, 2002 and 2001, respectively	(32)
Accumulated other comprehensive income (loss)	(12,747)
Total equity	692,977
Total liabilities and equity	$ 842,715

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

SPINNAKER EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

	Year Ended December 31,		
	2002	2001	2000
REVENUES	$188,326	$210,376	$121,383
EXPENSES:			
Lease operating expenses	18,212	12,132	9,009
Depreciation, depletion and amortization--natural gas and oil properties	108,998	85,059	47,451
Depreciation and amortization--other	914	398	309
General and administrative	10,984	9,443	7,350
Charges related to Enron bankruptcy	128	3,059	--
Total expenses	139,236	110,091	64,119
INCOME FROM OPERATIONS	49,090	100,285	57,264
OTHER INCOME (EXPENSE):			
Interest income	1,014	3,574	2,908
Interest expense, net	(762)	(381)	(748)
Total other income (expense)	252	3,193	2,160

INCOME BEFORE INCOME TAXES	49,342	103,478	59,424
Income tax expense	17,763	37,252	20,858
NET INCOME	$ 31,579	$ 66,226	$ 38,566
NET INCOME PER COMMON SHARE:			
Basic	$ 1.00	$ 2.45	$ 1.70
Diluted	$ 0.97	$ 2.34	$ 1.61
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:			
Basic	31,695	27,079	22,679
Diluted	32,653	28,360	24,011

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

SPINNAKER EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF EQUITY

(In thousands, except share data)

	Shares Issued		Par Value		Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Trea… Sto…
	Preferred	Common	Preferred	Common			
Balance, December 31, 1999	--	20,426,192	$--	$204	$203,987	$(27,034)	$(
Net income	--	--	--	--	--	38,566	
Comprehensive income							
Common stock issuance, net of issuance costs	--	5,600,000	--	56	138,342	--	
Exercise of stock options	--	462,478	--	5	3,195	--	
Employer contributions to 401(k) Plan	--	5,923	--	--	148	--	
Stock compensation costs	--	--	--	--	158	--	
Tax benefit associated with exercise of non-qualified stock options	--	--	--	--	3,676	--	
Balance, December 31, 2000	--	26,494,593	$ --	$265	$349,506	$ 11,532	$(
Net income	--	--	--	--	--	66,226	
Other comprehensive income, net of tax:							
Cumulative effect of accounting change for							

derivative financial instruments................	--	--	--	--	--	--	
Net change in fair value of derivative financial instruments................	--	--	--	--	--	--	
Financial derivative settlements reclassed to income.....................	--	--	--	--	--	--	
Comprehensive income........							
Exercise of stock options...	--	808,863	--	8	7,142	--	
Employer contributions to 401(k) Plan................	--	5,456	--	--	216	--	
Stock compensation costs....	--	--	--	--	114	--	
Tax benefit associated with exercise of non-qualified stock options.............	--	--	--	--	9,015	--	
	--	----------	----	----	--------	--------	--
Balance, December 31, 2001....	--	27,308,912	$ --	$273	$365,993	$ 77,758	$(
Net income.................	--	--	--	--	--	31,579	
Other comprehensive income, net of tax:							
Net change in fair value of derivative financial instruments................	--	--	--	--	--	--	
Financial derivative settlements reclassed to income.....................	--	--	--	--	--	--	
Comprehensive income........							
Common stock issuance, net of issuance costs..........	--	5,750,000	--	58	227,326	--	
Exercise of stock options...	--	116,489	--	1	948	--	
Employer contributions to 401(k) Plan................	--	9,062	--	--	287	--	
Stock compensation costs....	--	--	--	--	177	--	
Tax benefit associated with exercise of non-qualified stock options.............	--	--	--	--	1,356	--	
	--	----------	----	----	--------	--------	--
Balance, December 31, 2002....	--	33,184,463	$ --	$332	$596,087	$109,337	$(
	==	==========	====	====	========	========	==

	Comprehensive Income (Loss)
Balance, December 31, 1999....	
Net income.................	$ 38,566

Comprehensive income........	$ 38,566
	========
Common stock issuance, net of issuance costs..........	
Exercise of stock options...	
Employer contributions to	

401(k) Plan................	
Stock compensation costs....	
Tax benefit associated with exercise of non-qualified stock options.............	
Balance, December 31, 2000....	
Net income..................	$ 66,226
Other comprehensive income, net of tax:	
Cumulative effect of accounting change for derivative financial instruments................	(27,126)
Net change in fair value of derivative financial instruments................	35,502
Financial derivative settlements reclassed to income.....................	6,131
Comprehensive income........	$ 80,733
Exercise of stock options...	
Employer contributions to 401(k) Plan................	
Stock compensation costs....	
Tax benefit associated with exercise of non-qualified stock options.............	
Balance, December 31, 2001....	
Net income..................	$ 31,579
Other comprehensive income, net of tax:	
Net change in fair value of derivative financial instruments................	(24,269)
Financial derivative settlements reclassed to income.....................	(2,985)
Comprehensive income........	$ 4,325
Common stock issuance, net of issuance costs..........	
Exercise of stock options...	
Employer contributions to 401(k) Plan................	
Stock compensation costs....	
Tax benefit associated with exercise of non-qualified stock options.............	
Balance, December 31, 2002....	

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

SPINNAKER EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Year Ended December 31		
	2002	2001	2
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 31,579	$ 66,226	$ 3
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	109,912	85,457	4
Deferred income tax expense	18,063	36,977	2
Other	881	549	
Change in operating assets and liabilities:			
Accounts receivable	(13,443)	21,465	(3
Accounts payable and accrued liabilities	7,726	(3,216)	1
Other assets	(759)	1,979	(
Net cash provided by operating activities	153,959	209,437	8
CASH FLOWS FROM INVESTING ACTIVITIES:			
Oil and gas properties	(356,601)	(287,225)	(16
Proceeds from sale of natural gas and oil assets	--	--	
Purchases of other property and equipment	(7,216)	(1,603)	(
Purchases of short-term investments	--	(29,627)	(2
Sales of short-term investments	--	52,014	
Net cash used in investing activities	(363,817)	(266,441)	(18
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	37,000	--	1
Payments on borrowings	(37,000)	--	(1
Proceeds from issuance of common stock	227,873	--	13
Common stock issuance costs	(489)	--	
Proceeds from exercise of stock options	956	7,155	
Net cash provided by financing activities	228,340	7,155	14
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	18,482	(49,849)	4
CASH AND CASH EQUIVALENTS, beginning of year	14,061	63,910	2
CASH AND CASH EQUIVALENTS, end of year	$ 32,543	$ 14,061	$ 6
SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Cash paid for interest, net of amounts capitalized	$ 468	$ 190	$
Cash paid (received) for income taxes, net	$ (300)	$ 275	$

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

SPINNAKER EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization:

Spinnaker Exploration Company ("Spinnaker" or the "Company") was formed in 1996 and engages in the exploration, development and production of natural gas and oil properties in the U.S. Gulf of Mexico.

On September 28, 1999, the Company priced its initial public offering of 8,000,000 shares of common stock, par value $0.01 per share ("Common Stock"), and commenced trading the following day. After payment of underwriting discounts and commissions, the Company received net proceeds of $108.7 million on October 4, 1999. With a portion of the proceeds, the Company retired all outstanding debt of $72.0 million. In connection with the initial public offering, the Company converted all outstanding Series A Convertible Preferred Stock, par value $0.01 per share ("Preferred Stock"), into shares of Common Stock, and certain shareholders reinvested preferred dividends payable of $16.3 million into shares of Common Stock.

2. Summary of Significant Accounting Policies:

A summary of significant accounting policies followed in the preparation of the accompanying consolidated financial statements is set forth below:

General

The accompanying consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in the United States and pursuant to the rules and regulations of the Securities and Exchange Commission (the "Commission").

Principles of Consolidation

The accompanying consolidated financial statements include the activities and accounts of the Company and its subsidiaries, all of which are wholly owned. All significant intercompany transactions and balances are eliminated in consolidation.

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 disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates include depreciation, depletion and amortization ("DD&A") of proved natural gas and oil properties. Natural gas and oil reserve estimates, which are the basis for unit-of-production DD&A and the full cost ceiling test, are inherently imprecise and are expected to change as future information becomes available.

Cash Equivalents

The Company considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents.

Other Current Assets

Other current assets include unamortized debt financing costs of $0.3 million and $0.3 million at December 31, 2002 and 2001, respectively. Other non-current assets include unamortized debt financing costs of $0.3 million and $0.6 million at December 31, 2002 and 2001, respectively. These costs are amortized to interest

expense over the three-year term of the related credit facility. Amortization of these and other debt financing costs included in interest expense was $0.3 million, $0.2 million and $0.4 million for the years ended December 31, 2002, 2001 and 2000, respectively.

Full Cost Method of Accounting

The Company uses the full cost method of accounting for its investments in natural gas and oil properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for and developing natural gas and oil are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including those in progress, geological and geophysical service costs and depreciation of support equipment used in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of natural gas and oil properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of natural gas and oil. Substantially all the Company's exploration activities are conducted jointly with others and, accordingly, the natural gas and oil property balances reflect only its proportionate interest in such activities.

DD&A

The Company computes the provision for DD&A of natural gas and oil properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the amortization base until the properties associated with these costs are evaluated. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values.

Certain future development costs may be excluded from amortization when incurred in connection with major development projects expected to entail significant costs to ascertain the quantities of proved reserves attributable to the properties under development. The amounts that may be excluded are portions of the costs that relate to the major development project and have not previously been included in the amortization base and the estimated future expenditures associated with the development project. Such costs may be excluded from costs to be amortized until the earlier determination of whether additional reserves are proved or impairment occurs.

As of December 31, 2002, the Company excluded from the amortization base estimated future expenditures of $29.4 million associated with common development costs for its deepwater discovery at Front Runner. This estimate of future expenditures associated with common development costs is based on existing proved reserves to total proved reserves expected to be established upon completion of the Front Runner project.

Full Cost Ceiling

Capitalized costs of natural gas and oil properties, net of accumulated DD&A and related deferred taxes, are limited to the estimated future net cash flows from proved natural gas and oil reserves, including the effects of hedging activities in place as of December 31, 2002, discounted at 10%, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (the full cost ceiling). If capitalized costs of the full cost pool exceed the ceiling limitation, the excess is charged to expense.

Capitalized Employee and Other General and Administrative Costs

Under the full cost method of accounting, certain costs are capitalized that are directly identified with acquisition, exploration and development activities. These capitalized costs include salaries, employee benefits, costs of consulting services and other related costs and do not include costs related to production, general corporate overhead or similar activities. Spinnaker capitalized employee and other general and administrative costs of $5.9 million, $5.1 million and $3.8 million in 2002, 2001 and 2000, respectively.

Unproved Properties

The costs associated with unproved properties and properties under development are not initially included in the amortization base and relate to unevaluated leasehold acreage and delay rentals, seismic data, wells in-progress and wells pending determination. Unevaluated leasehold costs and delay rentals are either transferred to the amortization base with the costs of drilling the related well or are assessed quarterly for possible impairment or reduction in value. Unevaluated leasehold costs and delay rentals are transferred to the amortization base if a reduction in value has occurred. The costs of seismic data are transferred to the amortization base using the sum-of-the-year's-digits method over a period of six years. The costs associated with wells in-progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. The costs of drilling exploratory dry holes and associated leasehold costs are included in the amortization base immediately upon determination that the well is unsuccessful.

Of the $141.3 million of net unproved property costs at December 31, 2002 excluded from the amortizable base, net costs of $38.4 million, $19.7 million and $42.5 million were incurred in 2002, 2001 and 2000, respectively, and $40.7 million was incurred prior to 2000. The majority of the costs will be evaluated over the next five years.

Other Property and Equipment

Other property and equipment consists of computer hardware and software, office furniture and leasehold improvements. The Company is depreciating these assets using the straight-line method based upon estimated useful lives ranging from three to five years.

The costs associated with seismic hardware and software are included in other property and equipment. These costs are amortized into the full cost pool using the straight-line method over three years. Amortization was $1.5 million, $0.5 million and $1.2 million in 2002, 2001 and 2000, respectively.

Revenue Recognition Policy

The Company records as revenue only that portion of production sold and delivered and allocable to its ownership interest in the related property. Imbalances arise when a purchaser takes delivery of more or less volume from a property than the Company's actual interest in the production from that property. Such imbalances are reduced either by subsequent recoupment of over-and-under deliveries or by cash settlement, as required by applicable contracts. Under-imbalances included in accounts receivable were $0.6 million and $0.7 million at December 31, 2002 and 2001, respectively. Over-imbalances included in accrued liabilities were $2.5 million and $0.7 million at December 31, 2002 and 2001, respectively.

Income Taxes

Under Statement of Financial Accounting Standards ("SFAS") No. 109, "Accounting for Income Taxes," deferred income taxes are recognized at each year-end for the future tax consequences of differences between the

tax bases of assets and liabilities and their financial reporting amounts based on enacted tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable income. Valuation allowances are established when necessary to reduce deferred tax assets to the amount expected to be realized.

Stock-Based Compensation

SFAS No. 148, "Accounting for Stock-Based Compensation--Transition and Disclosure," amends SFAS No. 123 to provide alternative methods of transition for an entity that voluntarily changes to the fair value based method of accounting for stock-based employee compensation and to require prominent disclosure about the effects on reported net income of an entity's accounting policy decisions with respect to stock-based employee compensation. SFAS No. 148 amends Accounting Principles Board ("APB") Opinion No. 28, "Interim Financial Reporting," to require disclosure about those effects in interim financial information.

SFAS No. 123, "Accounting for Stock-Based Compensation," encourages, but does not require, companies to record compensation cost for stock-based employee compensation plans at fair value. The Company has chosen to account for stock-based compensation using the intrinsic value method prescribed in APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the fair value of the Common Stock at the date of the grant over the amount an employee must pay to acquire the Common Stock. In accordance with APB Opinion No. 25, compensation expense related to stock-based compensation was $0.2 million, $0.1 million and $0.2 million in 2002, 2001 and 2000, respectively. Had compensation cost for the Company's stock option compensation plans been determined based on the fair value at the grant dates for awards under these plans consistent with the method of SFAS No. 123, the Company's pro forma net income and pro forma net income per common share would have been as follows (in thousands, except per share amounts):

	Year Ended December 31,		
	2002	2001	2000
Net income, as reported	$31,579	$66,226	$38,56
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	114	73	10
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(8,902)	(8,920)	(3,12
Pro forma net income	$22,791	$57,379	$35,54
Net income per common share:			
Basic, as reported	$ 1.00	$ 2.45	$ 1.7
Basic, pro forma	$ 0.72	$ 2.12	$ 1.5
Diluted, as reported	$ 0.97	$ 2.34	$ 1.6
Diluted, pro forma	$ 0.70	$ 2.02	$ 1.4

For purposes of the SFAS No. 123 disclosure, the fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model with assumptions for grants in 2002, 2001 and 2000 as follows:

	Year Ended December 31,		
	2002	2001	2000
Risk-free interest rate	3.98%-5.28%	4.85%-5.57%	5.14%-6.82%
Volatility factor	62.2%	43.0%	42.5%
Dividend yield	0%	0%	0%
Expected life of the options (years)	4	4	4

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS--(Continued)

Financial Instruments and Price Risk Management Activities

At December 31, 2002, the Company's financial instruments consisted of cash and cash equivalents, receivables, payables and derivative instruments. The carrying amounts of cash and cash equivalents, receivables and payables approximate fair value because of the short-term nature of these items. The Company enters into hedging arrangements from time to time to reduce its exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. These hedging arrangements take the form of swap contracts or cashless collars and are placed with major trading counterparties.

On January 1, 2001, the Company adopted SFAS No. 133, as amended, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 established accounting and reporting standards requiring that all derivative instruments be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in a derivative's fair value be realized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset related results on the hedged items in the statement of operations and requires a company to formally document, designate and assess the effectiveness of transactions that qualify for hedge accounting. Upon adoption of SFAS No. 133 on January 1, 2001, the Company designated its open derivative contracts as cash flow hedges and recorded (i) a net current liability of $41.7 million, representing the fair market value of all derivatives on that date and (ii) a reduction of equity through accumulated other comprehensive income (loss) of $27.1 million, representing the fair market value of the derivatives as of January 1, 2001, net of deferred income taxes of $14.6 million.

Concentration of Credit Risk

Financial instruments that potentially subject the Company to concentration of credit risk consist principally of cash equivalents and trade accounts receivable. Derivative contracts also subject the Company to concentration of credit risk. Management believes that the credit risk posed by this concentration is mitigated by its hedging policy. The hedging policy requires that (i) at no time will any hedging agreement of any nature have a counterparty with a minimum long-term senior unsecured indebtedness rating less than "BBB+" by Standard & Poor's or "Baa1" by Moody's Investors Services, Inc. at the time that such counterparty entered into the relevant transaction under such hedging agreement and (ii) at no time will exposure to any single counterparty exceed 25% of the estimated twelve-month production volumes from total proved reserves.

The Company had in place both financial hedge and physical contracts with Enron North America Corp. at the time Enron Corp. and its subsidiaries filed for bankruptcy in December 2001. Spinnaker did not receive payment for fixed price swap contracts totaling $2.1 million which were intended to hedge December 2001 natural gas sales, and $1.4 million related to November 2001 natural gas production sold to Enron entities. The Company has recorded a net reserve of $3.2 million related to these receivables.

New Accounting Pronouncements

SFAS No. 143, "Accounting for Asset Retirement Obligations," requires entities to record a liability for asset retirement obligations at fair value in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. SFAS No. 143 is effective for financial statements issued for fiscal years beginning after June 30, 2002 using a cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation, depletion and amortization. The Company will adopt SFAS No. 143 effective January 1, 2003. The Company expects the adoption of this statement to result in the recognition of a liability for asset retirement obligations of approximately $22-$26 million, approximately $2-$4 million of which will be included in current liabilities and approximately $20-$22

million of which will be included in non-current liabilities, an increase in property and equipment of approximately $18-$22 million in the Company's balance sheets, and a cumulative accounting adjustment of approximately $2-$4 million recorded as expense, net of taxes of $1-$2 million, as the effect of the change in accounting principle.

SFAS No. 148, "Accounting for Stock-Based Compensation--Transition and Disclosure," amends SFAS No. 123 to provide alternative methods of transition for an entity that voluntarily changes to the fair value based method of accounting for stock-based employee compensation and to require prominent disclosure about the effects on reported net income of an entity's accounting policy decisions with respect to stock-based employee compensation. SFAS No. 148 amends APB Opinion No. 28, "Interim Financial Reporting," to require disclosure about those effects in interim financial information. SFAS No. 148 is effective for financial statements for fiscal years ending after December 15, 2002.

3. Accounts Receivable, Other Current Assets and Accrued Liabilities and Other:

Supplemental disclosures related to accounts receivable, other current assets and accrued liabilities and other are as follows (in thousands):

	As of December 31,	
	2002	2001
Accounts receivable:		
Natural gas and oil sales	$24,434	$10,679
Hedging receivable	2,093	2,093
Joint interest billings	10,430	8,735
Insurance claims receivable	3,127	4,593
Other receivables	720	1,088
Allowance for doubtful accounts	(3,232)	(3,059)
Total accounts receivable	$37,572	$24,129
Other current assets:		
Deferred tax assets associated with hedging activities	$ 7,170	$ 115
Drilling advances	2,060	710
Prepaid insurance	648	1,664
Prepaid debt financing costs	301	328
Other	1,259	847

Total other current assets	$11,438	$ 3,664
Accrued liabilities and other:		
Accrued liabilities	$38,542	$43,510
Deferred income taxes associated with hedging activities.	--	7,208
Total accrued liabilities and other	$38,542	$50,718

4. Debt:

In October 1999, the Company, Bank of Montreal and Credit Suisse First Boston entered into the $25.0 million Amended and Restated 364-Day Credit Agreement ("First Amended Credit Agreement"). The First Amended Credit Agreement was amended on July 20, 2000. The Second Amended and Restated Credit Agreement provided a $75.0 million credit facility ("Second Amended Credit Agreement") with an initial borrowing base of $40.0 million and an original term of 364 days. The borrowing base as of December 31, 2000

was $30.0 million. The Second Amended Credit Agreement was renewed for an additional 364-day term on July 18, 2001 before being terminated on December 28, 2001.

On December 28, 2001, the Company replaced its $75.0 million credit facility with an unsecured $200.0 million credit facility ("Credit Facility") with a group of seven banks. The borrowing base of the three-year Credit Facility is re-determined on or about April 30 and September 30 each year. The banks and Spinnaker also have the option to request one additional re-determination each year. The banks determine the borrowing base at their sole discretion and in their usual and customary manner. The amount of the borrowing base is a function of the banks' view of the Company's reserve profile as well as commodity prices. The current borrowing base is $100.0 million. The Company has the option to elect to use a base interest rate as described below or the LIBOR rate plus, for each such rate, a spread based on the percentage of the borrowing base used at that time. The base interest rate under the Credit Facility is a fluctuating rate of interest equal to the higher of either Toronto-Dominion Bank's base rate for dollar advances made in the United States or the Federal Funds Rate plus 0.5% per annum. The commitment fee rate ranges from 0.3% to 0.5%, depending on the borrowing base usage.

The Credit Facility contains various covenants and restrictive provisions, including the following limitations, subject to some exceptions, where the Company:

- may not incur any other indebtedness from borrowings, except for indebtedness arising under hedging agreements, indebtedness incurred in the ordinary course of business not to exceed $1.0 million, unsecured vendor indebtedness of the Company related to purchases of 2-D and 3-D seismic data made in the ordinary course of business in an amount not to exceed $25.0 million, other unsecured indebtedness in an amount not to exceed $10.0 million in the aggregate;

- may not incur any liens upon properties or assets other than permitted liens securing indebtedness of up to $1.0 million, liens on the 2-D and 3-D seismic data securing the indebtedness permitted to acquire such data, pledges or deposits to secure hedging agreements up to $15.0 million, liens on property required as a condition to enter into a synthetic lease transaction in the ordinary course of business and other liens in the ordinary course of business;

- may not dispose of any assets or properties except obsolete equipment, inventory sold in the ordinary course of business, reserves in non-proved categories, a second license in certain seismic data, or interests in natural gas and oil properties included in the borrowing base in an aggregate amount not to exceed $25.0 million in any fiscal year;

- may not make or pay any dividend, distribution or payment in respect of capital stock nor purchase, redeem, acquire, retire or permit any reduction or retirement of capital stock in excess of $10.0 million in any fiscal year;

- must maintain the ratio of consolidated current assets to consolidated current liabilities as of the end of each fiscal quarter so that it is not less than 1.00 to 1.00. For purposes of the calculation, availability under the Credit Facility is included as current assets, any payments of principal owing under the Credit Facility required to be repaid within one year from the time of the calculation are excluded from current liabilities and mark-to-market hedging exposure is excluded from both current assets and current liabilities;

- must maintain a tangible net worth so that it is not less than the sum of 80% of the tangible net worth as of September 30, 2001, plus 50% of the adjusted consolidated net income for each fiscal quarter since the closing of the Credit Facility, plus 75% of the proceeds from the sale of any security, including without limitation, common equity, preferred equity or other equity interests or equity securities including warrants, options and the like issued after the closing of the Credit Facility; and

- may not enter into any hedging agreement unless the percent of volumes to be hedged to estimated production volumes for such month from total internally-projected proved reserves does not exceed: 100% for the period one to three months from and after the hedging agreement transaction date, 66 2/3% for the period four to 18 months from and after the hedging agreement transaction date and 33 1/3% for the period 19 to 36 months from and after the hedging agreement transaction date. Additionally, at no time will any hedging agreement of any nature have a counterparty with a minimum long-term senior unsecured indebtedness rating less than "BBB+" by Standard & Poor's or "Baa1" by Moody's Investors Services, Inc. at the time that such counterparty entered into the relevant transaction under such hedging agreement and at no time will exposure to any single counterparty exceed 25% of the estimated twelve-month production volumes from total proved reserves.

At December 31, 2002, the Company was in compliance with the covenants and restrictive provisions and had no outstanding borrowings under the Credit Facility.

5. Equity:

Prior to Spinnaker's initial public offering in September 1999, the Company sold Preferred Stock to various investors. On September 28, 1999, the Company priced its initial public offering of 8,000,000 shares of Common Stock and commenced trading the following day. In connection with the initial public offering, the Company converted all outstanding Preferred Stock into 6,061,840 shares of Common Stock, and certain shareholders reinvested preferred dividends payable of $16.3 million into 1,200,248 shares of Common Stock. On August 16, 2000, the Company completed a public offering of 5,600,000 shares of Common Stock at $26.25 per share. After payment of underwriting discounts and commissions, the Company received net proceeds of $138.9 million. On December 20, 2000, PGS sold its 5,388,743 shares of Common Stock at $29.25 per share. Spinnaker received no proceeds from this sale. On April 3, 2002, the Company completed a public offering of 5,750,000 shares of Common Stock at $41.50 per share, including the over-allotment option consisting of 750,000 shares. After payment of underwriting discounts and commissions, the Company received net proceeds of $227.9 million.

Spinnaker has an effective shelf registration statement relating to the potential public offer and sale by the Company or certain of its affiliates of up to $500.0 million of any combination of debt securities, preferred stock, common stock, warrants, stock purchase contracts and trust preferred securities from time to time or when financing needs arise. The registration statement does not provide assurance that the Company will or could sell any such securities.

6. Stock Plans:

At December 31, 2002, officers, directors and employees had been granted options to purchase Common Stock under stock plans adopted in 1998, 1999, 2000 and 2001. The exercise price of each option equals the market price of Spinnaker's Common Stock on the date of grant. Stock option grants generally vest ratably over four years, with 20% vesting on the date of grant and 20% vesting in each of the succeeding four years, and expire after ten years. In the event of certain significant changes in control of the Company, all options then outstanding generally will become immediately exercisable in full.

In January 1998, the stockholders approved the 1998 Stock Option Plan ("1998 Plan"). The 1998 Plan was amended and restated in September 1999 and authorized the issuance of 2,673,242 shares of Common Stock. In September 1999, the stockholders approved the 1999 Stock Incentive Plan ("1999 Plan"). The number of shares of Common Stock that may be issued under the 1999 Plan may not exceed 1,300,000 shares. The maximum number of shares of Common Stock that may be subject to awards granted under the 1999 Plan to any one individual during any calendar year may not exceed 300,000 shares. In connection with the 1999 Plan, the

stockholders approved the Adjunct Stock Option Plan ("Adjunct Plan"). The number of shares of Common Stock that may be issued under the Adjunct Plan may not exceed 21,920 shares. In November 2000, the board of directors adopted the 2000 Stock Option Plan ("2000 Plan"). Stockholder approval was not required for the 2000 Plan. The number of shares of Common Stock that may be issued under the 2000 Plan may not exceed 500,000 shares. In May 2001, the stockholders approved the 2001 Stock Incentive Plan ("2001 Plan"). The number of shares of Common Stock that may be issued under the 2001 Plan may not exceed 1,500,000 shares. The maximum number of shares of Common Stock that may be subject to awards granted under the 2001 Plan to any one individual during any calendar year may not exceed 300,000 shares.

Presented below is a summary of stock option activity.

	2002		2001		2000	
	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weig Aver Exer Pri
Outstanding, beginning of year........	4,062,556	$22.08	3,718,886	$13.80	3,382,974	$10
Granted...........................	450,000	35.82	1,242,800	37.90	802,470	23
Exercised.........................	(119,433)	8.01	(810,991)	8.82	(466,558)	6
Forfeited.........................	(6,590)	27.64	(88,139)	17.57	--	
Outstanding, end of year.............	4,386,533	$23.87	4,062,556	$22.08	3,718,886	$13
Exercisable, end of year.............	2,845,250	$19.30	2,273,548	$16.16	2,364,270	$11
Available for grant, end of year......	204,535		648,545		303,206	
Weighted average fair value of options granted during the year............	$ 26.83		$ 23.76		$ 15.17	

The Company transferred treasury shares to certain employees in connection with their exercises of 2,944, 2,128 and 4,080 options in 2002, 2001 and 2000, respectively. Options to purchase 1,240 shares of Common Stock were forfeited during 2002 and 1999 and are not currently available for future grants due to exercise price restrictions under the 1998 Plan.

At December 31, 2002, the following options were outstanding and exercisable and had the indicated weighted average remaining contractual lives:

	Outstanding		Exercisable		
Range of Exercise Prices Per Share	Number of Options	Weighted Average Exercise Price Per Share	Number of Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Life (Years)
$2.50-$5.00	541,004	$ 4.94	541,004	$ 4.94	4.2
$14.50-$16.13	1,749,699	15.36	1,462,164	15.36	5.7
$21.58-$26.88	322,700	26.05	172,200	26.41	8.2
$31.33-$36.81	173,220	32.74	60,932	32.23	8.8
$37.35-$38.63	1,407,210	37.84	529,530	37.86	8.4
$39.35-$42.06	192,700	40.50	79,420	40.80	8.6

4,386,533	2,845,250

SPINNAKER EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS--(Continued)

7. Earnings Per Share:

Basic and diluted net income per common share is computed based on the following information (in thousands, except per share amounts):

	Year Ended December 31,		
	2002	2001	2000
Numerator:			
Net income available to common stockholders	$31,579	$66,226	$38,566
Denominator:			
Basic weighted average number of shares	31,695	27,079	22,679
Dilutive securities:			
Stock options	958	1,281	1,332
Diluted adjusted weighted average number of shares and assumed conversions	32,653	28,360	24,011
Net income per common share:			
Basic	$ 1.00	$ 2.45	$ 1.70
Diluted	$ 0.97	$ 2.34	$ 1.61

For the years ended December 31, 2002, 2001 and 2000, 1,680,640, 113,200 and 399,920 stock options that could potentially dilute earnings per share are excluded from the calculations as they were anti-dilutive.

8. Major Customers:

The Company had natural gas and oil sales to four customers accounting for approximately 52%, 13%, 11% and 11%, respectively, of total natural gas and oil revenues, excluding the effects of hedging activities, for the year ended December 31, 2002. The Company had natural gas and oil sales to four customers accounting for approximately 32%, 23%, 21% and 17%, respectively, of total natural gas and oil revenues, excluding the effects of hedging activities, for the year ended December 31, 2001. The Company had natural gas and oil sales to three customers accounting for approximately 61%, 11% and 11%, respectively, of total natural gas and oil revenues, excluding the effects of hedging activities, for the year ended December 31, 2000. One of the customers in 2001 and 2000 was Enron North America Corp. Spinnaker no longer sells its natural gas and oil production to this customer.

9. Related-Party Transactions:

The Company incurred charges of approximately $16.1 million and $16.3 million in 2002 and 2001, respectively, from affiliates of Baker Hughes Incorporated, an oilfield services company of which Mr. Michael E. Wiley, a director of Spinnaker since March 2001, serves as Chairman of the Board, Chief Executive Officer and President. The Company incurred charges of approximately $0.1 million, $0.1 million and $0.5 million in 2002, 2001 and 2000, respectively, from Cooper Cameron Corporation, an oilfield services company of which Mr. Sheldon R. Erikson, a director of Spinnaker, serves as Chairman of the Board, Chief Executive Officer and President.

10. Income Taxes:

The significant items giving rise to the deferred income tax assets and liabilities are as follows (in thousands):

	As of December 31, 2002	As of December 31, 2001
Deferred income tax liabilities:		
Basis differences in natural gas and oil properties.	$156,588	$104,141
Hedging activities................................	--	7,812
Total deferred income tax liabilities..........	156,588	111,953
Deferred income tax assets:		
Net operating losses...............................	$ 92,650	$ 58,400
Hedging activities................................	7,170	--
Other..	2,112	622
Total deferred income tax assets...............	101,932	59,022
Net deferred income tax liabilities..................	$ 54,656	$ 52,931

Tax benefits of $1.4 million and $9.0 million associated with the exercise of non-qualified stock options during the years ended December 31, 2002 and 2001 are reflected as a component of equity. The net deferred income tax liabilities include a deferred tax asset of $7.2 million and a deferred tax liability of $7.8 million related to the tax effect of the fair market value of derivatives at December 31, 2002 and 2001, respectively, as required by SFAS No. 133, as amended.

As of December 31, 2002, the Company had approximately $257.4 million of net operating loss carryforwards ("NOLs") that will begin expiring in 2018. For federal income tax purposes, certain limitations are imposed on an entity's ability to utilize its NOLs in future periods if a change of control, as defined for federal income tax purposes, has occurred. In general terms, the limitation on utilization of NOLs and other tax attributes during any one year is determined by the value of an entity at the date of the change of control multiplied by the then-existing long-term, tax-exempt interest rate. The Internal Revenue Service has not yet addressed the manner of determining an entity's value. The Company has determined that, for federal income tax purposes, a change of control occurred during 2000. However, the Company does not believe such limitations will significantly impact its ability to utilize the NOLs.

Significant components of the provision for income taxes are as follows (in thousands):

	Year Ended December 31,		
	2002	2001	2000
Current	$ (300)	$ 275	$ 25
Deferred	18,063	36,977	20,833
Income tax expense	$17,763	$37,252	$20,858

The differences between income tax expense and the amount that would be determined by applying the statutory federal income tax rate of 35% to the income before income taxes are as follows (in thousands):

	Year Ended December 31,		
	2002	2001	2000
Federal income tax expense at statutory rates	$17,270	$36,217	$20,798
Non-deductible expenses and other	493	1,035	659
Valuation allowance	--	--	(599)
Income tax expense	$17,763	$37,252	$20,858

During 2000, the Company expected that it would realize all of its deferred tax assets and therefore decreased the valuation allowance to $0.

11. Commitments and Contingencies:

The Company is, from time to time, party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on the financial position, results of operations or cash flows of the Company.

Employment Contracts

The Company has employment contracts with certain of its executive officers. These contracts provide for annual base salaries, bonus compensation, various benefits and the continuation of salary and benefits for the respective terms of the agreements in the event of termination of employment for various reasons, and whether by the Company or the employee. These agreements are subject to automatic annual extensions unless terminated.

Employee 401(k) Retirement Plan

In July 1998, the Company instituted a 401(k) retirement savings plan ("401(k) Plan") for its employees. The 401(k) Plan provides that all qualified employees may defer the maximum income allowed under current tax law. The 401(k) Plan covers all employees at least 21 years of age.

Effective January 1, 2000, the Company began matching employee contributions to the 401(k) Plan. The Company matches 100% of each participant's contributions up to 6% of the participant's annual base salary. In connection with the employer match, the Company issued 9,062 shares of Common Stock valued at $0.3 million in 2002, 5,456 shares of Common Stock valued at $0.2 million in 2001 and 5,923 shares of Common Stock valued at $0.1 million in 2000.

Leases

The Company leases administrative offices under a non-cancelable operating lease expiring in 2007. The lease agreement requires the Company pay for utilities, maintenance and other operational expenses of the building. Additionally, the lease contains escalation clauses. The Company also leases office equipment and oil and gas equipment under non-cancelable operating leases. Rental expense was $1.6 million, $0.7 million and $0.5 million in 2002, 2001 and 2000, respectively. Minimum future obligations under non-cancelable operating

leases at December 31, 2002 for the following five years are $1.7 million, $1.3 million, $1.3 million, $1.2 million and $0.5 million, respectively.

Summary of Contractual Obligations

The Company had no long-term debt, capital lease or purchase obligations or other contractual long-term liabilities as of December 31, 2002. The Company has incurred obligations in the ordinary course of business under purchase and service agreements that are not included in the table below, including obligations of approximately $35.4 million and $6.7 million in 2003 and 2004, respectively, for construction of the Green Canyon Blocks 338/339 ("Front Runner") spar production facility. Contractual obligations as of December 31, 2002 are as follows:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Operating leases............	$6,032	$1,708	$3,800	$524	$--
Other contractual obligations	--	--	--	--	--
Total....................	$6,032	$1,708	$3,800	$524	$--

12. Commodity Price Risk Management Activities:

The Company enters into New York Mercantile Exchange ("NYMEX") related swap contracts and collar arrangements from time to time. The Company's swap contracts and collar arrangements will settle based on the reported settlement price on the NYMEX for the last trading day of each month for natural gas.

In a swap transaction, the counterparty is required to make a payment to the Company for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. The Company is required to make a payment to the counterparty for the difference between the fixed price and the settlement price if the settlement price is above the fixed price. As of December 31, 2002, Spinnaker's commodity price risk management positions in fixed price natural gas swap contracts and related fair value were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Price (Per MMBtu)	Fair Value (in thousands)
First Quarter 2003.	60,000	$3.71	$ (5,979)
Second Quarter 2003	53,297	3.55	(4,411)
Third Quarter 2003.	50,000	3.55	(4,068)
Fourth Quarter 2003	50,000	3.63	(4,340)
Year 2003..........	53,288	$3.61	$(18,798)

In a collar arrangement, the counterparty is required to make a payment to the Company for the difference between the fixed floor price and the settlement price if the settlement price is below the fixed floor price. The Company is required to make a payment to the counterparty for the difference between the fixed ceiling price and the settlement price if the settlement price is above the fixed ceiling price. Neither party is required to make a payment if the settlement price falls between the fixed floor price and the fixed ceiling price. As of December 31, 2002, Spinnaker's commodity price risk management positions in natural gas collar arrangements and related fair value were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Floor Price (Per MMBtu)	Weighted Average Ceiling Price (Per MMBtu)	Fair Value (in thousands)
First Quarter 2003.	15,000	$3.25	$5.21	$ (228)
Second Quarter 2003	15,000	3.25	5.21	(262)
Third Quarter 2003.	15,000	3.25	5.21	(287)
Fourth Quarter 2003	15,000	3.25	5.21	(342)
Year 2003..........	15,000	$3.25	$5.21	$(1,119)

The Company reported a net liability of $19.9 million and a net asset of $22.3 million related to its derivative contracts at December 31, 2002 and 2001, respectively. Amounts related to hedging activities as of December 31, 2002 and 2001 were as follows (in thousands):

	As of December 31, 2002	2001
Current assets:		
Hedging asset..	$ --	$20,593
Deferred income tax asset related to hedging activities.....	7,170	--
Non-current assets:		
Hedging asset..	$ --	$ 1,726
Current liabilities:		
Hedging liability..	$ 19,917	$ --
Deferred income tax liability related to hedging activities.	--	7,208
Non-current liabilities:		
Deferred income tax liability related to hedging activities.	$ --	$ 604
Accumulated other comprehensive income (loss):		
Accumulated other comprehensive income (loss)...............	$(19,917)	$22,319
Income taxes..	7,170	(7,812)
Accumulated other comprehensive income (loss)...........	$(12,747)	$14,507

The Company recognized a net hedging gain of $4.7 million and net hedging losses of $9.6 million and $18.7 million in revenues in 2002, 2001 and 2000, respectively. There was no ineffective component of the derivatives recognized in earnings in 2002 and 2001. Based on future natural gas prices as of December 31, 2002, the Company would reclassify a net loss of $12.7 million from accumulated other comprehensive income (loss) to earnings within the next twelve months. The amounts ultimately reclassified into earnings will vary due to changes in the fair value of the open derivative contracts prior to settlement.

SPINNAKER EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS--(Continued)

13. Quarterly Financial Data (Unaudited):

Quarterly operating results for the years ended December 31, 2002 and 2001 are summarized as follows (in thousands, except per share amounts):

	(Unaudited) Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2002:				
Revenues	$32,600	$37,164	$51,558	$67,004
Income from operations	8,963	9,256	11,042	19,829
Net income	5,576	6,222	7,146	12,635
Net income per common share:				
Basic	$ 0.20	$ 0.19	$ 0.22	$ 0.38
Diluted	$ 0.20	$ 0.18	$ 0.21	$ 0.37
2001:				
Revenues	$67,453	$59,500	$44,818	$38,605
Income from operations	42,792	32,886	16,150	8,457
Net income	28,148	21,781	10,803	5,494
Net income per common share:				
Basic	$ 1.05	$ 0.80	$ 0.40	$ 0.20
Diluted	$ 1.00	$ 0.77	$ 0.38	$ 0.19

14. Supplementary Financial Information on Oil and Gas Exploration, Development and Production Activities (Unaudited):

Capitalized Costs Related to Oil and Gas Producing Activities
(In thousands)

	As of December 31,	
	2002	2001
Capitalized costs:		
Proved properties	$ 879,840	$ 575,806
Unproved properties not being amortized	141,326	102,881
Total	1,021,166	678,687
Accumulated depreciation, depletion and amortization(1)	(267,744)	(158,746)
Net capitalized costs	$ 753,422	$ 519,941

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(1) Depreciation, depletion and amortization per Mcfe was $2.12, $1.60 and $1.57 in 2002, 2001 and 2000, respectively.

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities
(In thousands)

	Year Ended December 31,		
	2002	2001	2000
Acquisition costs:			
Unproved....................	$ 39,789	$ 34,524	$ 21,421
Proved......................	--	--	--
Exploration costs...............	163,322	187,720	121,451
Development costs...............	139,368	80,276	51,144
Total costs incurred.....	$342,479	$302,520	$194,016

Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including those in progress, geological and geophysical service costs and depreciation of support equipment used in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines.

Costs being excluded from amortization consist of the following (in thousands):

	Year Ended December 31,				
	Total	2002	2001	2000	1999 and Prior
Unproved property costs	$ 89,837	$28,635	$22,362	$ 4,910	$33,930
Exploration costs......	49,751	11,306	(5,880)	37,559	6,766
Development costs......	1,738	(1,496)	3,234	--	--
Total...............	$141,326	$38,445	$19,716	$42,469	$40,696

Results of Operations for Oil and Gas Producing Activities
(In thousands)

Year Ended December 31,

	2002	2001	2000
Revenues	$188,326	$210,376	$121,383
Operating expenses(1)	18,212	12,132	9,009
Depreciation, depletion and amortization	108,998	85,059	47,451
Charges related to Enron bankruptcy	128	3,059	--
Income tax expense(2)	21,956	39,645	23,372
Results of operations	$ 39,032	$ 70,481	$ 41,551

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(1) Operating expenses represent costs incurred to operate and maintain wells and related equipment and facilities. These costs include, among other things, workover expenses, labor, materials, supplies, property taxes, insurance, severance taxes and transportation expenses.

(2) Income tax expense is calculated by applying the statutory tax rate to operating profit, then adjusting for any applicable permanent tax differences or tax credits and allowances.

Proved natural gas and oil reserve quantities and the related discounted future net cash flows before income taxes are based on estimates prepared by Ryder Scott Company, L.P., independent petroleum consultants. Such estimates have been prepared in accordance with guidelines established by the Commission.

Proved reserves are estimated quantities of natural gas and oil that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can reasonably be expected to be recovered through existing wells with existing equipment and operating methods.

Reserve Quantity Information

	Natural Gas (MMcf)	Oil and Condensate (MBbls)	Natural Gas Equivalents (MMcfe)
Proved reserves as of December 31, 1999	90,030	2,412	104,501
Extensions, discoveries and other additions	97,665	1,027	103,829
Revisions of previous estimates	5,248	(116)	4,552
Production	(28,845)	(225)	(30,194)
Proved reserves as of December 31, 2000	164,098	3,098	182,688
Extensions, discoveries and other additions	74,531	18,921	188,057
Revisions of previous estimates	(11,414)	2,829	5,556
Production	(51,234)	(310)	(53,094)

Proved reserves as of December 31, 2001(1)	175,981	24,538	323,207
Extensions, discoveries and other additions	24,666	7,678	70,733
Revisions of previous estimates(2)	(11,936)	(1,168)	(18,944)
Production	(45,180)	(1,040)	(51,419)
Proved reserves as of December 31, 2002(1)	143,531	30,008	323,577
Proved developed reserves:			
December 31, 2002(1)	84,139	2,219	97,456
December 31, 2001(1)	82,221	748	86,711
December 31, 2000	112,315	1,042	118,568
December 31, 1999	50,756	384	53,062

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(1) Spinnaker has a 25% non-operator working interest in a significant deepwater oil discovery at Front Runner. This significant oil discovery changed Spinnaker's reserve profile. Proved oil and condensate reserves were 56% and 46% of total proved reserves at December 31, 2002 and 2001, respectively, compared to 10% at December 31, 2000. Of the Company's total proved reserves as of December 31, 2002, 70% were proved undeveloped reserves. Front Runner represented more than 60% of total proved undeveloped reserves.

(2) Front Runner area reserves are subject to royalty relief on the first 87.5 million equivalent barrels of oil produced. As new reserves are added in the Front Runner area, changes in future production assumptions result in a reallocation of reserves subject to royalty relief. These reallocations resulted in downward revisions to previous estimates of approximately 671 MMcf and 1,002 MBbls, or natural gas equivalents of 6,681 MMcfe. No downward revision on any individual property exceeded 1% of proved reserves as of December 31, 2001.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

- Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions.

- The estimated future gross revenues of proved reserves are priced on the basis of year-end market prices.

- The future gross revenue streams are reduced by estimated future costs to develop and to produce the proved reserves, as well as certain abandonment costs based on year-end cost estimates and the estimated effect of future income taxes.

- Future income taxes are computed by applying the statutory tax rate to future net cash flows reduced by the tax basis of the properties, the estimated permanent differences applicable to future natural gas and oil producing activities and tax carryforwards.

The standardized measure of discounted future net cash flows is not intended to present the fair market value of the Company's natural gas and oil reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves in excess of proved reserves, anticipated future changes in prices and costs, an allowance for return on investment and the risks inherent in reserve estimates. Given the volatility of natural gas and oil prices, it is reasonably possible that the Company's estimate of discounted future net cash flows from proved natural gas and oil reserves will change in the near term. If natural gas and oil prices decline, even if for only a short period of time, or if the Company has significant downward revisions to its estimated proved reserves, it is possible that write-downs of natural gas and oil properties could occur in the future.

Standardized Measure of Discounted Future Net Cash Flows
(In thousands)

	Year Ended December 31,		
	2002	2001	2000
Future cash inflows(1)	$1,613,724	$ 944,861	$1,730,754
Future operating expenses	(185,782)	(164,105)	(60,259)
Future development costs	(184,441)	(191,711)	(68,929)
Future net cash flows before income taxes	1,243,501	589,045	1,601,566
Future income taxes	(259,436)	(120,489)	(516,488)
Future net cash flows	984,065	468,556	1,085,078
10% annual discount	(303,267)	(139,000)	(185,941)
Standardized measure of discounted future net cash flows	$ 680,798	$ 329,556	$ 899,137

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(1) Prices for natural gas and oil used to calculate future cash inflows were $4.91, $2.71 and $9.99 per Mcf of natural gas and $30.50, $19.23 and $30.41 per barrel of oil as of December 31, 2002, 2001 and 2000, respectively.

Principal Sources of Change in the Standardized Measure of Discounted Future Net Cash Flows
(In thousands)

	Year Ended December 31,		
	2002	2001	200
Standardized measure, beginning of year	$ 329,556	$ 899,137	$ 151,
Extensions and discoveries, net of related costs	215,800	198,709	719,
Sales of natural gas and oil produced, net of production costs	(165,450)	(207,824)	(131,
Net changes in prices and production costs	403,728	(958,755)	486,
Change in future development costs	(26,795)	(18,959)	(3,
Development costs incurred during the period that reduced future development costs	56,831	47,463	37,

Revisions of quantity estimates................................	(57,991)	6,092	34,
Accretion of discount...	(640)	132,067	15,
Net change in income taxes......................................	(80,892)	335,952	(421,
Change in production rates and other............................	6,651	(104,326)	9,
Standardized measure, end of year.................................	$ 680,798	$ 329,556	$ 899,

INDEPENDENT AUDITORS' REPORT ON CONSOLIDATED
FINANCIAL STATEMENT SCHEDULE

To the Board of Directors and Stockholders of
Spinnaker Exploration Company:

Under date of February 7, 2003, we reported on the consolidated balance sheets of Spinnaker Exploration Company and subsidiaries, as of December 31, 2002 and 2001, and the related consolidated statements of operations, equity and cash flows for each of the years in the three-year period ended December 31, 2002. In connection with our audits of the aforementioned consolidated financial statements, we also audited the related consolidated financial statement schedule. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statement schedule based on our audits.

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

KPMG LLP

Houston, Texas
February 7, 2003

Schedule II

SPINNAKER EXPLORATION COMPANY

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

For the Years Ended December 31, 2002, 2001 and 2000
(In thousands)

	Balance at Beginning of Year	Charged to Costs and Expenses	Deductions and Other	Balance at End of Year
Year ended December 31, 2002:				
Allowance for doubtful accounts.	$3,059	$ 128	$45	$3,232
Year ended December 31, 2001:				
Allowance for doubtful accounts.	$ --	$3,059	$--	$3,059

Year ended December 31, 2000:				
Allowance for doubtful accounts.	$ --	$ --	$--	$ --

EXHIBIT INDEX

Exhibit Number	Description
3.1	--Certificate of Incorporation of Spinnaker, as amended (incorporated by reference to Exh Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
3.2	--Restated Bylaws of Spinnaker (incorporated by reference to Exhibit 3.2 to Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
4.1	--Specimen Common Stock certificate (incorporated by reference to Exhibit 4.1 to Spinnake Registration Statement on Form S-3 (Commission File No. 333-72238))
10.1	--Second Amended and Restated Data Contribution Agreement between Petroleum Geo-Services ASA, Seismic Energy Holdings, Inc., Spinnaker Exploration Company, L.L.C. and Spinnaker dated June 30, 1999 (incorporated by reference to Exhibit 10.1 to Spinnaker's Registrat Statement on Form S-1 (Commission File No. 333-83093))
10.2	--Amended and Restated 1998 Spinnaker Stock Option Plan (incorporated by reference to Exh 10.2 to Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
10.3	--Amended and Restated Stockholders Agreement by and among Spinnaker, Warburg, Pincus Ventures, Petroleum Geo-Services, Roger L. Jarvis, James M. Alexander, William D. Hubba Kelly M. Barnes and certain other stockholders of Spinnaker (including the Registration Agreement as Exhibit A to the Stockholders Agreement) (incorporated by reference to Exh 10.3 to Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
10.3.1	--First Amendment to the Amended and Restated Stockholders Agreement by and among Spinnak Warburg, Pincus Ventures, Petroleum Geo-Services, Roger L. Jarvis, James M. Alexander, William D. Hubbard, Kelly M. Barnes and certain other stockholders of Spinnaker (incorp by reference to Exhibit 10.3.1 to Spinnaker's Quarterly Report on Form 10-Q for the qua June 30, 2000)
10.5	--Credit Agreement for a $200 million credit facility dated as of December 28, 2001 (inco by reference to Exhibit 10.5 to Spinnaker's Annual Report on Form 10-K for the year end December 31, 2001)
10.6	--Employment Agreement between Spinnaker and Roger L. Jarvis dated December 20, 1996, as amended (incorporated by reference to Exhibit 10.6 to Spinnaker's Registration Statemen Form S-1 (Commission File No. 333-83093))
10.7	--Employment Agreement between Spinnaker and William D. Hubbard dated February 24, 1997, amended (incorporated by reference to Exhibit 10.8 to Spinnaker's Registration Statemen Form S-1 (Commission File No. 333-83093))
10.8	--Employment Agreement between Spinnaker and Kelly M. Barnes dated February 24, 1997, as amended (incorporated by reference to Exhibit 10.9 to Spinnaker's Registration Statemen Form S-1 (Commission File No. 333-83093))
10.9	--1999 Spinnaker Stock Incentive Plan (incorporated by reference to Exhibit 10.10 to Spin Registration Statement on Form S-1 (Commission File No. 333-83093))
10.10	--1999 Spinnaker Employee Stock Purchase Plan (incorporated by reference to Exhibit 10.11 Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
10.11	--Form of Indemnification Agreement (incorporated by reference to Exhibit 10.12 to Spinna Registration Statement on Form S-1 (Commission File No. 333-83093))
10.12	--Adjunct Stock Option Plan (incorporated by reference to Exhibit 4.3 to Spinnaker's Regi Statement on Form S-8 (Commission File No. 333-36592))
10.13	--Spinnaker Exploration Company 2000 Stock Option Plan (incorporated by reference to Exhibit 10.13 to Spinnaker's Annual Report on Form 10-K for the year ended December 31,

Exhibit Number	Description
10.14	--Spinnaker Exploration Company 2001 Stock Incentive Plan, as amended (incorporated by reference to Exhibit 10.2 to Spinnaker's Registration Statement on Form S-8 (Commission No. 333-61888))
12.1*	--Calculation of Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Prefe Dividends
21.1	--Subsidiaries of Spinnaker Exploration Company (incorporated by reference to Exhibit 21. Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
23.1*	--Consent of KPMG LLP
23.2*	--Consent of Ryder Scott Company, L.P.
99.1*	--Certification of Chief Executive Officer of Spinnaker Exploration Company pursuant to 1 U.S.C. Section 1350
99.2*	--Certification of Chief Financial Officer of Spinnaker Exploration Company pursuant to 1 U.S.C. Section 1350

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* Filed herewith.