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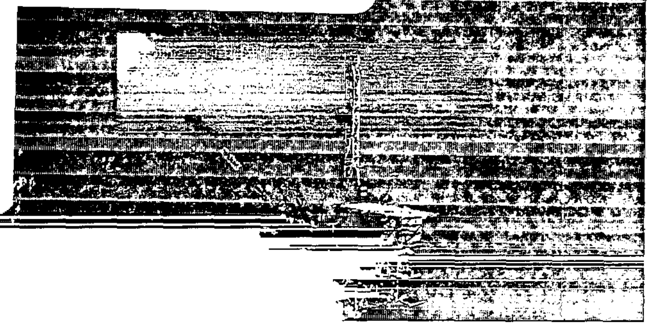
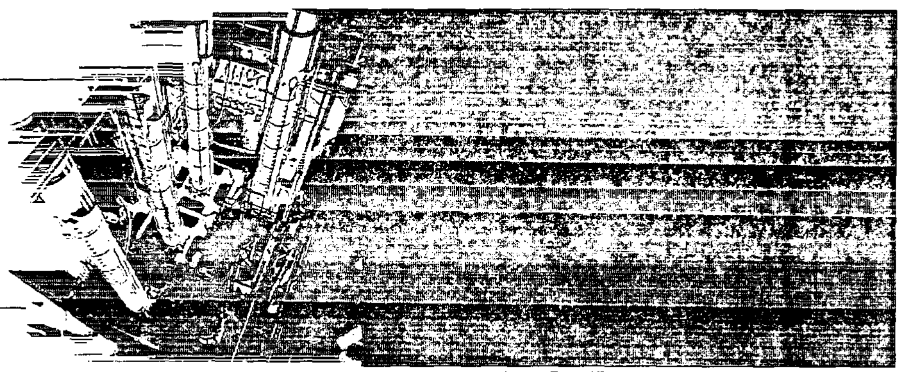
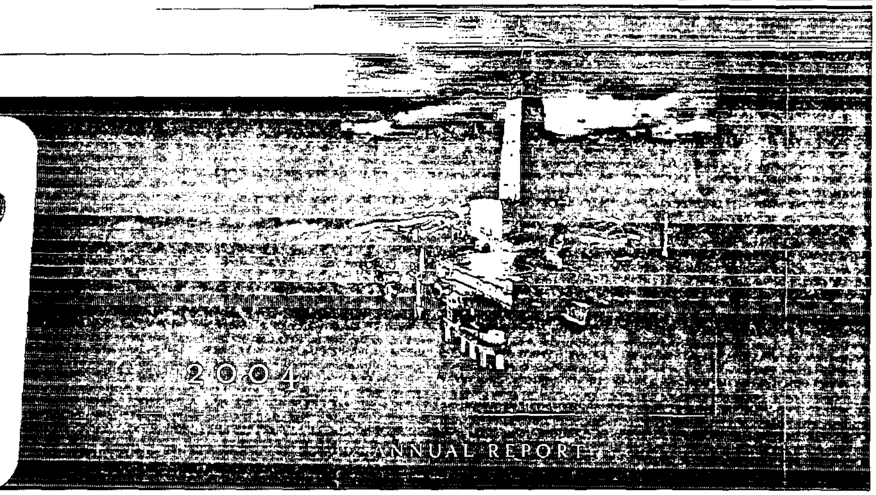


PINNAKER EXPLORATION COMPANY





2004

ANNUAL REPORT

cik 1089697

[illegible] PROFILE

Spinnaker Exploration Company, a Delaware corporation, is an independent energy company engaged in the exploration, development and production of oil and gas in the U.S. Gulf of Mexico ("Gulf of Mexico") and West Africa. Formed in December 1996, we became a publicly traded company in September 1999.

We were formed based on a business model that focuses on information and technology – a large 3-D seismic database combined with the application of sophisticated geophysical processing technologies. As of December 31, 2004, we owned licenses to approximately 21,600 blocks of mostly contiguous 3-D seismic data in the Gulf of Mexico. This database covers an area of approximately 4.6 million acres, which we believe is one of the largest 3-D seismic databases of any independent exploration and production company in the Gulf of Mexico.

From inception through December 31, 2004, we participated in drilling [illegible] wells in the Gulf of Mexico resulting in 104 discoveries. Historically, most of the wells we drilled were on the shelf. However, we are in the process of transitioning to more deepwater operations.

As of December 31, 2004, Ryder Scott Company, L.P., our independent reserve engineers, estimated our net proved reserves at approximately 306.7 Bcfe. Proved oil and condensate reserves were [illegible]% of total proved reserves and proved undeveloped reserves were approximately 66% of total proved reserves as of December 31, 2004, primarily related to our significant deepwater oil discovery at [illegible].

We are headquartered in Houston, Texas. Our common shares are traded on the New York Stock Exchange under the symbol "SKE."

FINANCIAL HIGHLIGHTS

(THOUSANDS OF DOLLARS, EXCEPT PER SHARE AMOUNTS)

FOR THE YEAR ENDED DECEMBER 31,	2004	2003	2002
Revenues	$ 272,888	$ 226,850	$ 188,326
Income from operations	85,281	63,160	49,090
Net income	53,933	36,612	31,579
Net income per common share:			
Basic	1.60	1.10	1.00
Diluted	1.55	1.08	0.97
Cash from operations:			
Net cash provided by operating activities	219,732	198,110	153,959
Changes in operating assets and liabilities	12,557	(7,041)	6,476
Cash from operations	232,289	191,069	160,435
Capital costs incurred	265,735	306,383	348,193

AS OF DECEMBER 31,			
Cash and cash equivalents	$ 21,830	$ 15,315	$ 32,543
Property and equipment, net	1,061,137	939,668	760,854
Total assets	1,150,931	990,582	842,715
Long-term debt	105,000	50,000	–
Equity	814,086	744,061	692,977

SPINNAKER EXPLORATION COMPANY

OPERATING HIGHLIGHTS

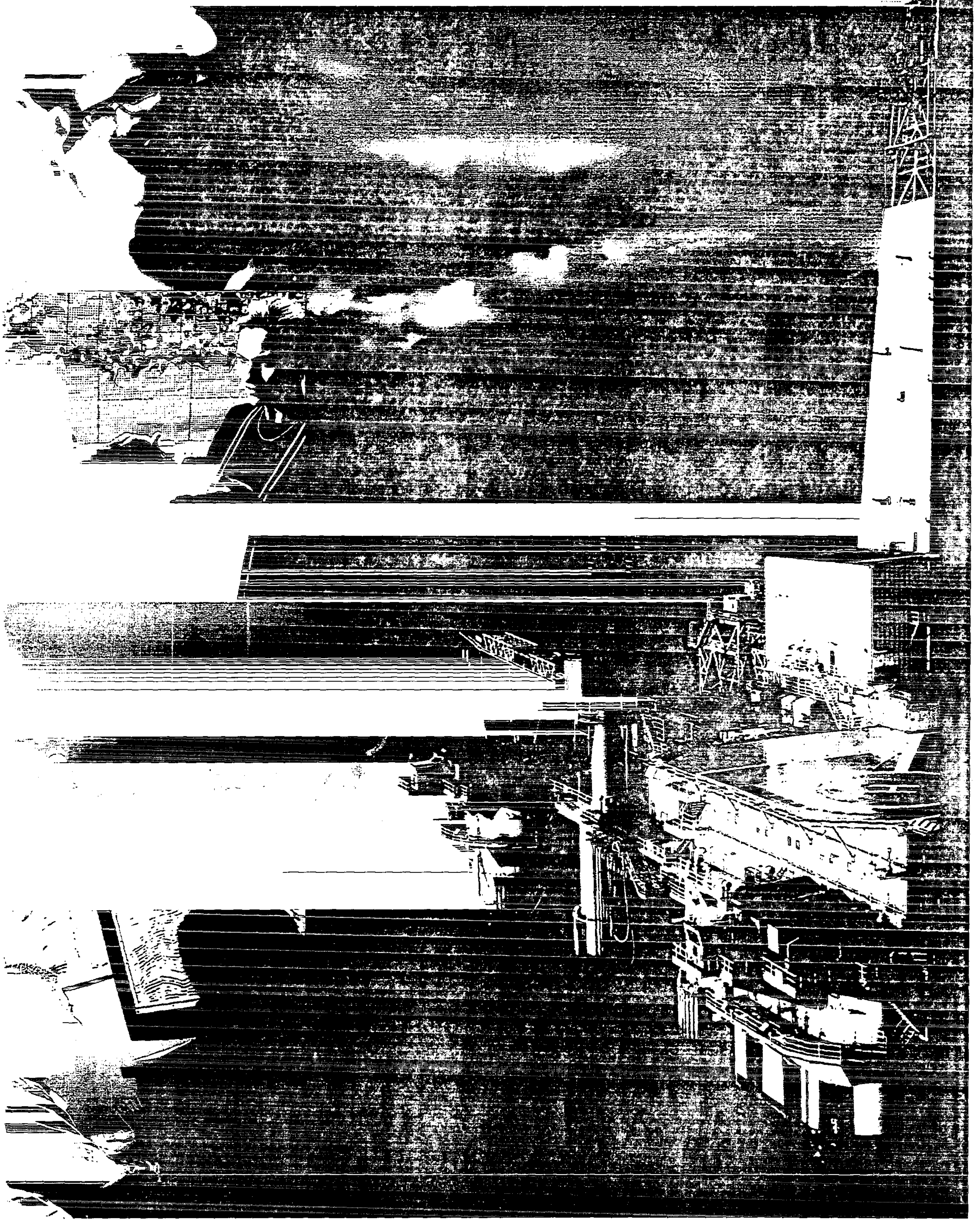
	2004	2003	2002
Production (MMcfe)	46,188	49,010	51,419
Percent natural gas production	77%	83%	88%
Average realized natural gas price per Mcf (1)	$ 5.73	$ 4.53	$ 3.56
Average realized oil and condensate price per barrel	$ 39.06	$ 30.56	$ 26.39
Proved reserves (MMcfe)	306,722	332,581	323,577
Percent proved oil and condensate reserves	52%	54%	56%
Present value of future net cash flows (before income taxes) discounted at 10% (in thousands) (2)	$ 1,045,943	$ 1,064,647	$ 847,273
Lease acreage (net acres, in thousands)	906	819	742
3-D seismic data coverage (millions of acres)	46	45	40

(1) Including the effects of hedging activities

(2) Calculated using prices of $6.38, $6.29 and $4.91 per Mcf of natural gas and $37.25, $30.34 and $30.50 per barrel of oil as of December 31, 2004, 2003 and 2002, respectively

SHELF

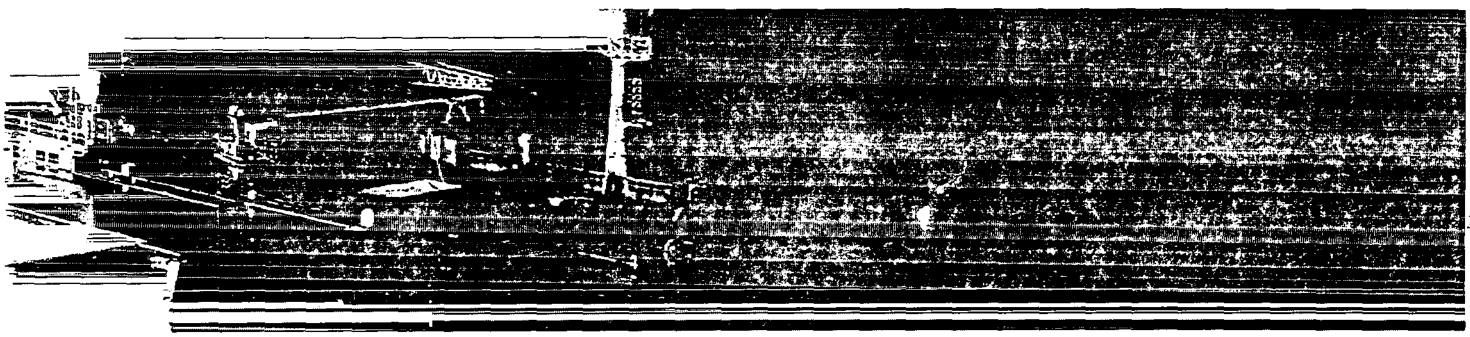
Growth in our near-term production is dependent upon our exploratory success on the shelf. With a significant inventory of leasehold acreage and reprocessed seismic data in our core shelf areas, we consistently explore for high-potential, high-quality opportunities that will add meaningful new resources and near-term production. We currently concentrate our shelf exploration efforts in the upper Miocene sands of the deep shelf. In 2004, we drilled nine successful wells on the shelf. Five of these discoveries commenced production in 2004, and we expect that the remaining four wells will commence production in the first half of 2005.

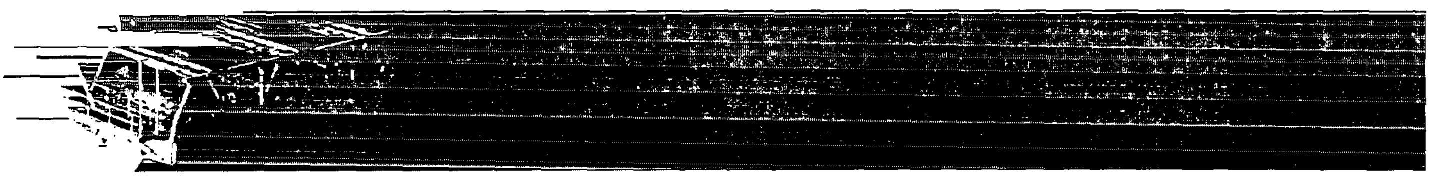


DEEPWATER

EXPLORATION

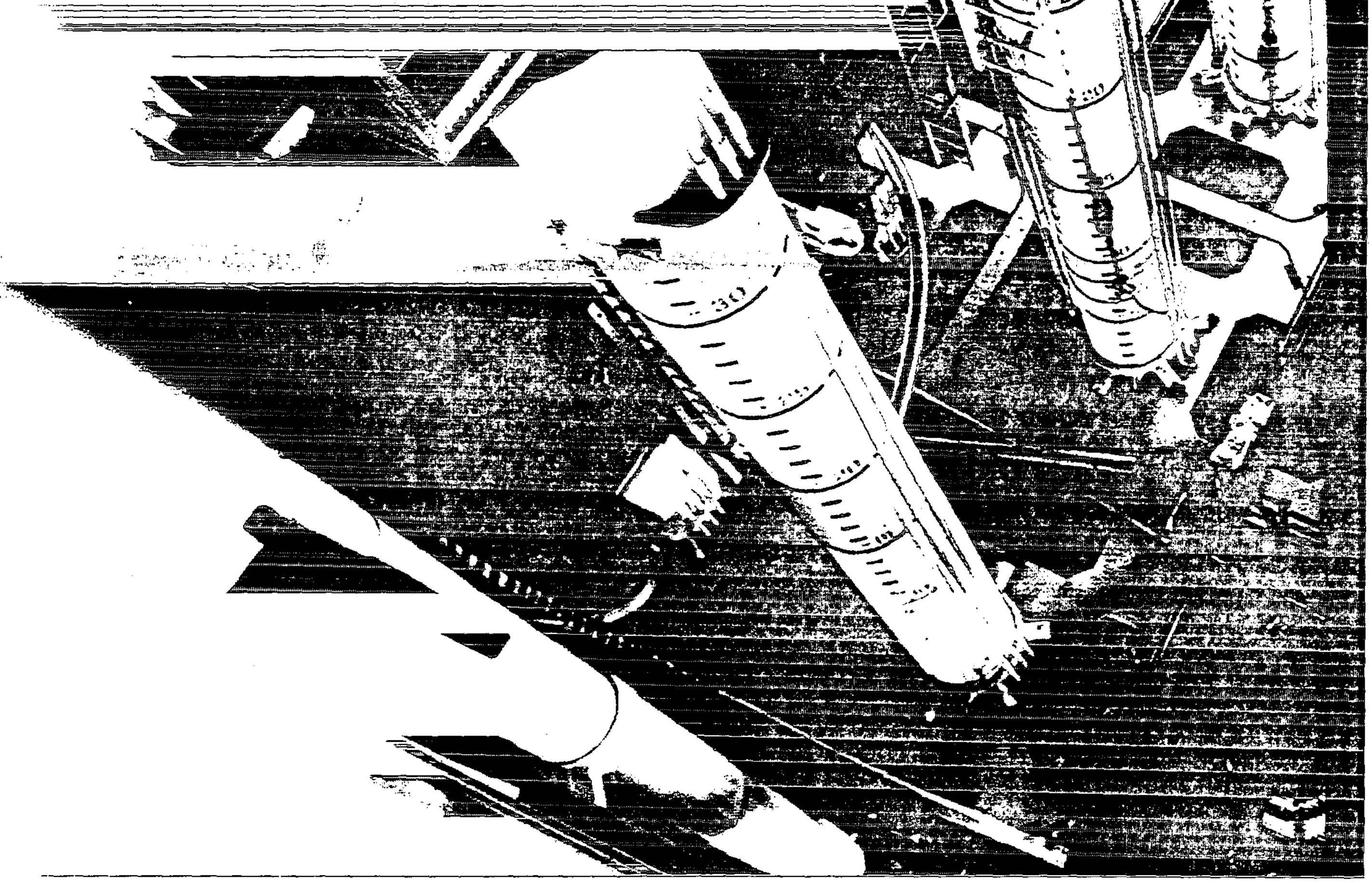
Since 2001, we have drilled 32 deepwater wells, 21 of which were successful. Our most significant deepwater projects include oil discoveries at Green Canyon Blocks 338/339/382 (Front Runner) and Mississippi Canyon 496 (Zia) and natural gas discoveries in the Eastern Gulf at DeSoto Canyon Blocks 618/619 (San Jacinto) and Blocks 620/621 (Spiderman). Our transition and expansion into the deep water is further evidenced by our 2004 discovery at Mississippi Canyon 734 (Thunder Hawk), where we are currently drilling our second well and evaluating development options for this area. We expect to drill approximately ten deepwater wells in the Gulf of Mexico and two deepwater wells in West Africa in 2005.

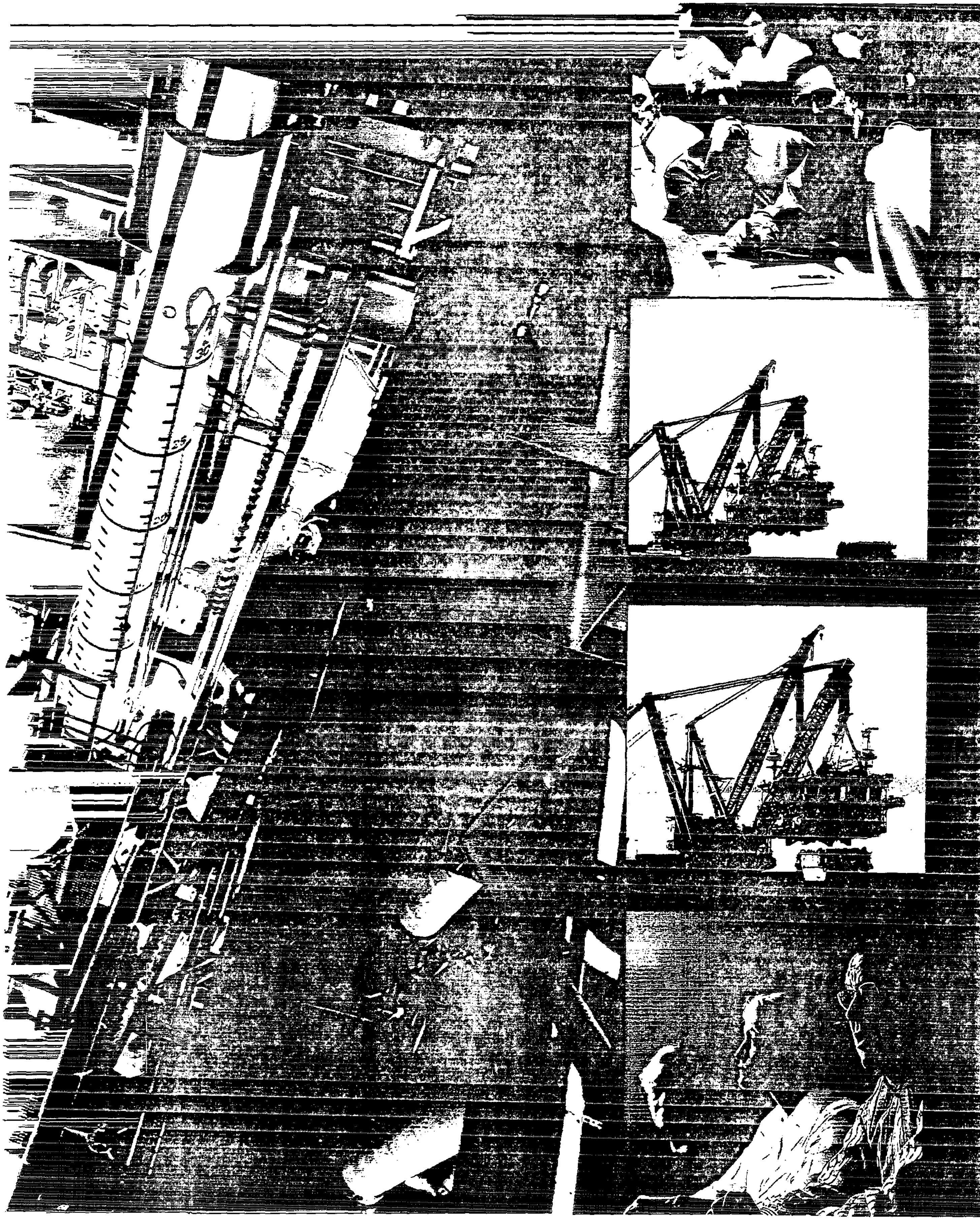




DEEPWATER PRODUCTION

A landmark event for us occurred on December 4, 2004 when production commenced from the first of nine wells at Front Runner. A second well commenced production in March 2005. We anticipate that additional wells will be completed in 2005 until the Front Runner spar production facility reaches its estimated full oil capacity of 60,000 barrels per day. Our first deepwater oil discovery at Mississippi Canyon 496 (Zia) commenced production in 2003. Deepwater production as a percent of total production has increased from approximately 3% in 2001 to [illegible]% in 2004. We anticipate that production from our deepwater operations will be approximately 40% of our total production in 2005.





EASTERN GULF

Our Spiderman and San Jacinto discoveries in late 2003 and 2004 positioned Spinnaker as a key player in the development of the Eastern Gulf of Mexico. We were instrumental in guiding the project toward an optimal commercial and technical solution. The fields will be developed via subsea tieback to the Independence Hub, a floating production facility (FPF), located in Mississippi Canyon 920. The FPF will be owned by third party merchants and capable of processing 850 million cubic feet of gas per day. We own 10.6% of the processing rights associated with this facility and the export pipelines. We anticipate first production in 2007. The expanding infrastructure in the Eastern Gulf strengthens the exploratory feasibility in this prospect-rich province.

To Our

SHAREHOLDERS

We enjoyed another good year at Spinnaker in 2004. For the year, we earned approximately $54 million, or $1.55 per share, on record revenues of $273 million. Cash from operations of $232 million was also a record for us. Oil and gas prices remain robust in what now must be called the most sustained high pricing cycle in the history of our industry. Demand for the commodities that we find is high at a time when the supply is tight and in an environment that seems unlikely to change in the near term.

A large contribution to this favorable pricing environment is, however, the increased cost of and difficulty in locating new significant supplies of oil and gas. If it was easy or inexpensive, the market would not support these prices. So, while we believe that the current cycle will continue to make it possible to achieve excellent results, we are focusing ever more intensely on what we do best – exploring for oil and gas – while mindful of the costs to find and produce our products.

Historically, 88% of our total production has been natural gas, including 77% of total production in 2004. However, we have been transitioning to more deepwater operations since 2001 when we made the discovery at Front Runner. As a result, we anticipate that oil production by year-end 2005 will be approximately one-half of our total production. We expect revenue, earnings and cash flow growth in 2005 as our exposure to high oil prices increases.

We have been transitioning to more deepwater operations since 2001 when we made the discovery at Front Runner. As a result, we anticipate that oil production by year-end 2005 will be approximately one-half of our total production.

FRONT RUNNER TIMELINE

01/01 INITIAL FRONT RUNNER DISCOVERY

06/01 FRONT RUNNER SOUTH DISCOVERY

08/01 QUATRAIN DISCOVERY

02/02 PROJECT SANCTION

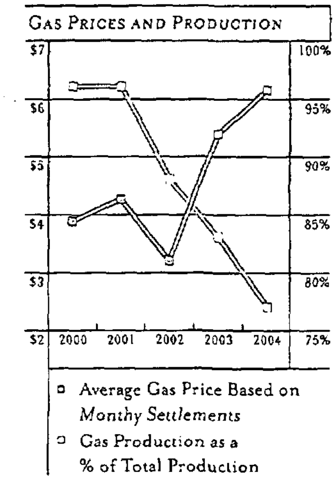
03/02 SPAR CONTRACT EXECUTED

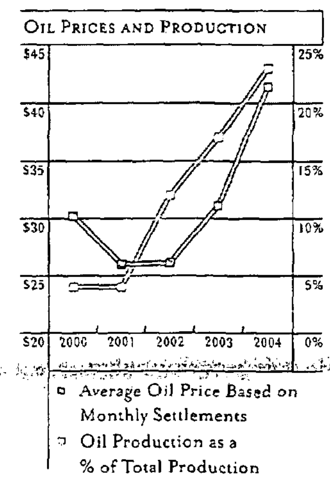
04/03 SPAR UNDER CONSTRUCTION IN DUBAI

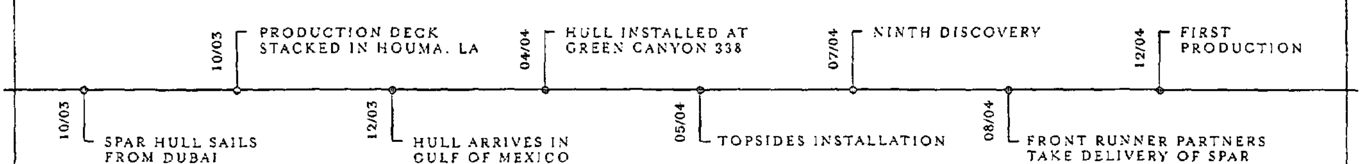
Spinnaker took meaningful steps in 2004 to further define itself and add to its exploratory positioning. In the Gulf of Mexico, we achieved production from our first stand-alone field development at the Front Runner field complex. A total of nine wells have been drilled in the area, two of which were completed and are currently producing. A spar production facility is installed and capable of processing 70,000+ barrels of oil equivalent per day once the ramp-up is complete. This is a great achievement for Spinnaker and a window on our rapidly progressing deepwater presence.

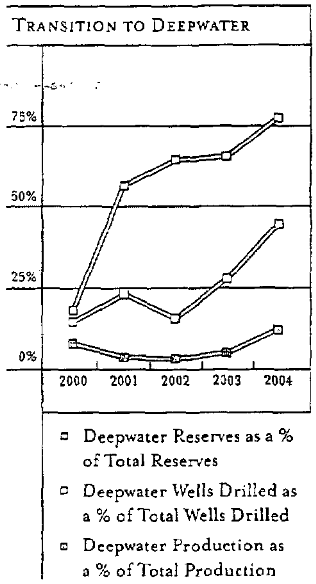
During 2004, we also defined another major project through which we will extend our deepwater identity. The Independence Hub is now under construction in Singapore and will be a Floating Production Facility ("FPF") capable of processing 850 million cubic feet of gas per day. The facility will set a world record for water depth development of approximately 8,100 feet upon installation. Spinnaker's personnel are heavily involved in the design and construction phase of this $1.3 billion project.

The Independence Hub and a pipeline, the Independence Trail, will bring to market the first greatly needed supplies of gas from the recently opened Eastern Gulf of Mexico. The project is a creative model for future industry cooperation. The FPF will be owned by third party merchants and will initially allow multiple gas fields owned by five companies to come to market. The ownership model allows us to focus on exploration and allows





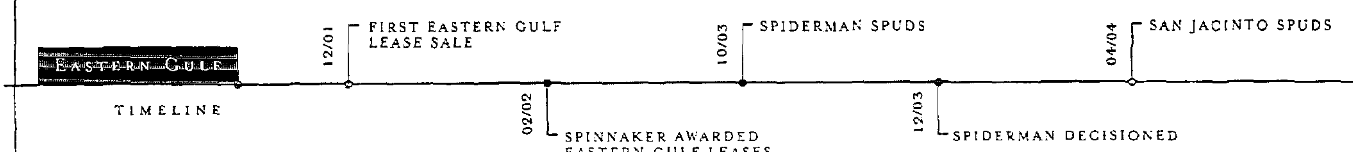




others to do what they do best. We own about 11% of the processing privileges at the Independence Hub, and we expect the project to contribute to our operating and financial results beginning in 2007. We will produce gas from our Spiderman and San Jacinto discoveries through the hub, and we are looking for more supplies via our ample prospect inventory in the Eastern Gulf area.

We found another potentially large field in the deep water of the Gulf of Mexico during 2004. The Thunder Hawk field is adjacent to and related to the huge Thunderhorse Field Complex in Mississippi Canyon. The Company's internal seismic processing capability and terrific exploration staff were responsible for this meaningful find. The field is currently being delineated and we and our partners are aggressively examining development options. The reservoirs at Thunder Hawk are thick and capable of producing at high rates. Our 25% interest in the field should represent significant future volumes of oil production.

Spinnaker also saw its due diligence efforts in the international arena come to fruition as we recently announced our participation in OPL Block 256 offshore Nigeria with a subsidiary of Devon Energy Corporation. The transfer of interest is pending various approvals within the Nigerian government. The block is large (631,000 acres) and holds outstanding potential. We have examined opportunities in various parts of the world for several



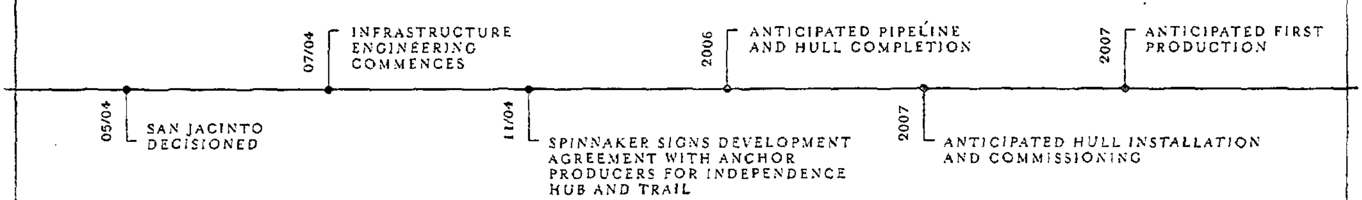
years and are quite excited about this initial investment. We possess specific knowledge in this area and can apply both exploration and production technology in a similar fashion as in the Gulf of Mexico. We intend to build a business in this area and consider West Africa to be one of the two or three most prospective basins in the world.

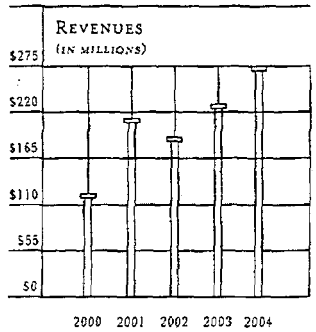
We continue to be active on the shelf of the Gulf of Mexico as well. While only about 25% of our capital budget will be spent on the shelf in 2005, this continues the trend that began for us in the late 1990's. We really like the prospects we intend to drill in this play in 2005 and have ample inventory, but we will be careful to ensure that high natural gas prices do not make our capital expenditures inefficient at the margin. We will pursue only the larger and/or higher-quality inventory, even at the expense of production maintenance in the near-term.

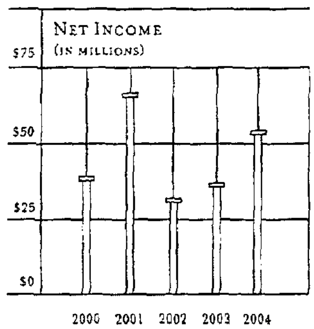
In summation, the exploration and production business is good. We believe that 2004 was a landmark year in our continuing transition as a high-potential explorer. As always, we are very appreciative of our great staff, our thoughtful and supportive Board of Directors and to you, our shareholders.

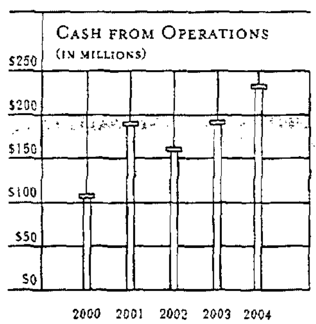
Roger L. Jarvis
Chairman of the Board, President and Chief Executive Officer

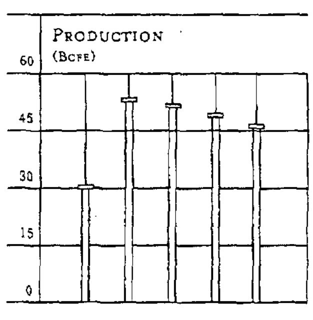
We believe that 2004 was a landmark year in our continuing transition as a high-potential explorer.











We recognized net income of $53.9 million in 2004, or $1.55 per diluted share, compared to 2003 net income of $36.6 million, or $1.08 per diluted share. The 47% increase in net income was primarily due to higher commodity prices. Other 2004 financial and operating highlights included the following:

- Revenues increased $46.0 million, or 20%, to a record $272.9 million;
  - Oil and condensate revenues increased $25.6 million, or 59%;
  - Average oil and condensate price increased 29% to $39.45 per barrel;
  - Natural gas revenues decreased $9.5 million, or 4%;
  - Average natural gas price increased 8% to $5.92 per Mcf; and
  - Hedging losses and other decreased $29.9 million, or 80%.
- Income from operations increased $22.1 million, or 35%, to $85.3 million;
- Cash from operations increased $41.2 million, or 22%, to a record $232.3 million; and
- Production decreased approximately 2.8 Bcfe, or 6%, to 46.2 Bcfe.
  - Natural gas production decreased 12%; and
  - Oil and condensate production increased 23%.

We ended 2004 with cash and cash equivalents of $21.8 million and long-term debt of $105.0 million. Net additions to property and equipment in 2004 were $265.7 million.

Looking forward, we have capital expenditure plans for 2005 totaling approximately $280.0 million. Based on this level of capital expenditures and current oil and gas prices, we expect our cash flow from operations to exceed our capital expenditures for the first time since our inception.

SPINNAKER EXPLORATION COMPANY

2004 10-K

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

FORM 10-K

☒ Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2004.

☐ 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 ☒ No ☐

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was approximately $1,056,683,000 based on the closing sales price of $39.38 per share of the registrant's common stock as reported by the New York Stock Exchange as of June 30, 2004, the last business day of the registrant's most recently completed second fiscal quarter. For purposes of the preceding sentence only, all directors, executive officers and beneficial owners of ten percent of more of the common stock are assumed to be affiliates.

The number of shares outstanding of the registrant's common stock, par value $0.01 per share, on March 11, 2005 was 33,949,327.

DOCUMENTS INCORPORATED BY REFERENCE

Parts of the registrant's Definitive Proxy Statement for the 2005 Annual Meeting of Stockholders to be held May 4, 2005 are incorporated by reference into Part III of this annual report on Form 10-K.

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Cautionary Statement About Forward-Looking Statements

In this annual report on Form 10-K ("Annual Report"), unless the context requires otherwise, when we refer to "Spinnaker," the "Company," "we," "us" or "our" we are describing Spinnaker Exploration Company and its subsidiaries.

Some of the information in this Annual Report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These forward-looking statements may be identified by the use of the words "anticipate," "believe," "contemplate," "estimate," "expect," "may," "plan," "will," "would" and similar expressions that contemplate future events. Forward-looking statements include all statements under "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Annual Report involving the discussion of the following:

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

Although we believe that these forward-looking statements are based on reasonable assumptions, our expectations may not occur and we cannot provide assurance that the anticipated future operating results will meet our expectations or be achieved. Numerous factors, risks and uncertainties could cause our actual future results to differ materially from the results implied by these or other forward-looking statements made by us or on our behalf. These factors include, among other things:

- the risks associated with exploration;
- delays in anticipated production start-up dates;
- shut-ins of production for platform, pipeline and facility maintenance, additions and removals;
- potential mechanical failure or under-performance of significant wells;
- the relatively short production lives of certain properties;
- the concentration of production and reserves in a small number of properties;
- maturity of the Gulf of Mexico shelf;
- oil and gas price volatility;
- our hedging activities;
- the ability to find, replace, develop and acquire oil and gas reserves;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production and the timing and amount of development expenditures;
- downward revisions of proved reserves and the related negative impact on the depreciation, depletion and amortization ("DD&A") rate;
- write-downs of oil and gas properties if oil and gas prices decline, proved reserves are revised downward or our finding and development costs continue to increase;
- operating hazards attendant to the oil and gas business;
- drilling and completion risks, which costs are generally not recoverable from third parties or insurance;
- weather risks and natural disasters;
- availability and cost of material and equipment;

- risks inherent in international operations;
- actions or inactions of third-party operators of our properties;
- the ability to find and retain skilled personnel;
- availability of capital;
- the strength and financial resources of competitors and customers;
- regulatory developments;
- environmental risks; and
- general economic conditions.

For additional discussion of these and other factors, risks and uncertainties, see "Item 1. Business," "Item 2. Properties" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in this Annual Report. The forward-looking statements speak only as of the date made, and we undertake no obligation to update such forward-looking statements.

We have provided definitions for some of the oil and gas industry terms used in this annual report on Form 10-K in the "Glossary of Oil and Gas Terms" on page 45.

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 oil and gas in the U.S. Gulf of Mexico ("Gulf of Mexico") and West Africa. We were formed based on a business model that focuses on information and technology—a large 3-D seismic database combined with the application of sophisticated geophysical processing technologies.

As of December 31, 2004, we owned licenses to approximately 21,600 blocks of mostly contiguous 3-D seismic data in the Gulf of Mexico. This database covers an area of approximately 46 million acres, which we believe is one of the largest 3-D seismic databases of any independent exploration and production company in the Gulf of Mexico. We believe that our regional 3-D seismic approach allows us to create and maintain a large inventory of high-quality prospects and provides the opportunity to enhance our exploration success and efficiently deploy our capital resources. We also believe that our licenses to large quantities of high-quality seismic data and our management and technical staff are important factors for our current and future success.

As of December 31, 2004, we had 329 leasehold interests located in federal and Texas state waters of the Gulf of Mexico covering approximately 1,593,000 gross and 906,000 net acres. Most of these leasehold interests were acquired through a competitive bid process at federal and state lease sales. Within our current inventory of leasehold interests, we have identified and captured approximately 150 exploratory prospects. Based on 3-D seismic analysis on blocks where we currently have no leasehold interest, we also have over 200 identified leads that may result in additional prospects.

From inception through December 31, 2004, we participated in drilling 176 wells in the Gulf of Mexico resulting in 104 discoveries. Historically, most of the wells we drilled were on the shelf. However, we are in the process of transitioning to more deepwater operations. Prior to 2001, we drilled nine deepwater wells, three of which were successful. Since 2001, we have drilled 32 deepwater wells, 21 of which were successful. In 2005, we expect to drill approximately nine additional deepwater wells in the Gulf of Mexico and two deepwater wells in West Africa. Our most significant deepwater projects include oil discoveries at Green Canyon Blocks 338/339/382 ("Front Runner") and natural gas discoveries in the Eastern Gulf of Mexico at DeSoto Canyon Blocks 618/619/620/621 ("Eastern Gulf Project"). Front Runner commenced production in December 2004 from the first of nine wells. We anticipate that additional wells will be completed in 2005 until the Front Runner spar production facility reaches its estimated full oil capacity of 60,000 barrels per day. The Eastern Gulf Project development plan is complete. The fields will be developed via subsea tieback to a floating production facility located in Mississippi Canyon 920 that will be capable of processing 850 MMcf of natural gas per day. We anticipate first production from the Eastern Gulf Project in 2007.

As of December 31, 2004, Ryder Scott Company, L.P. ("Ryder Scott"), our independent reserve engineers, estimated our net proved reserves at approximately 306.7 Bcfe. Of our total proved reserves as of December 31, 2004, approximately 66% were proved undeveloped reserves. Approximately 67% of our total proved undeveloped reserves relate to our significant deepwater oil discovery at Front Runner. We anticipate that a substantial percentage of our proved undeveloped reserves at Front Runner, although not all, will be re-categorized as proved developed reserves in 2005 as several of the eight existing non-producing wells in the Front Runner field are completed and commence production.

In order to diversify our operations and apply our skill set to other opportunities, we entered into a farm-out agreement in December 2004 covering a 12.5% interest in OPL Block 256 offshore Nigeria from Ocean Energy Nigeria Limited, a wholly-owned subsidiary of Devon Energy Corporation ("Devon"). The transfer of interest is pending various approvals within the Nigerian government. We expect our capital requirements for exploratory activities in connection with this venture to be approximately $50 million to $60 million over a two to three year period beginning in the first quarter of 2005. In connection with the farm-out agreement, we paid Devon approximately $11.8 million as reimbursement of prior expenses it incurred related to the block. We cannot provide assurance that we will receive approval of the transfer of interest from the Nigerian government. If we do not receive the Nigerian government approvals, the $11.8 million will be reimbursed to us by Devon.

We operate only one business segment. For a discussion of our results of operations for each of the last three years, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data."

Our current capital expenditure budget for 2005 is approximately $280.0 million, including $190.0 million for exploration activities and geological and geophysical expenditures, $45.0 million for development activities, $41.0 million for leasehold acquisitions and $4.0 million for other property and equipment. We currently plan to drill approximately 21 wells in 2005, including ten wells on the Gulf of Mexico shelf, nine wells in the deep water of the Gulf of Mexico and two wells in West Africa.

Our Chief Executive Officer, Warburg, Pincus Ventures, L.P. ("Warburg") and Petroleum Geo-Services ASA ("PGS") formed Spinnaker in December 1996. On December 20, 2000, PGS sold all of its shares of Spinnaker common stock, par value $0.01 per share. We received no proceeds from this sale.

Business Strategy

Our goals are to expand our reserve base, increase cash flow and net income and generate an attractive return on capital. We emphasize the following elements in our strategy to achieve these goals:

- Focus on the Gulf of Mexico;
- Evaluate and participate in international opportunities;
- Maintain a large database of 3-D seismic data in order to constantly upgrade our opportunity set;
- Employ a rigorous prospect selection process;
- Emphasize technical expertise; and
- Sustain a balanced, diversified exploration effort while maintaining a low debt-to-capitalization ratio.

Focus on the Gulf of Mexico. We have assembled a large 3-D seismic database, and through 2004 have focused our exploration activities in the Gulf of Mexico because we believe 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 oil and gas; and
- Geologic diversity that offers a variety of exploration opportunities.

We also believe our geographic focus provides an excellent opportunity to develop and maintain competitive advantages through the combination of our 3-D seismic database and regional exploration and operating expertise.

Evaluate and participate in international opportunities. In order to diversify our operations and apply our skill set to other opportunities, we entered into a farm-out agreement in December 2004 covering a 12.5% interest in OPL Block 256 offshore Nigeria from Devon. The transfer of interest is pending various approvals within the Nigerian government. This opportunity gives us exposure to a large acreage position that contains multiple prospects in a prolific basin.

Maintain a large database of 3-D seismic data in order to constantly upgrade our opportunity set. We believe our large database of original and reprocessed 3-D seismic data allows us to generate and maintain a large inventory of high-quality exploratory prospects. We are constantly upgrading our opportunity set both through lease sales and farm-ins of acreage held by other operators. Our 3-D seismic database serves as the foundation for our exploration program. We 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. We use our large inventory of mostly contiguous areas of 3-D seismic data to select prospects by tying regional 3-D seismic analysis to existing well control. Through this process, we enhance our understanding of the geology before selecting prospects and increase the probability of accurately identifying hydrocarbon-bearing zones. We use a systematic risking process to select prospects for drilling. We assess the probability for a prospect to be productive based on several geologic factors, including source, trap, seal, migration, reservoir quality and data quality. We also assess the likely range of recoverable reserves based on probabilistic ranges of productive area, sand thickness and recovery factor.

Emphasize technical expertise. We have a team of 16 explorationists with significant experience in exploration in the Gulf of Mexico. We also have a team of eight technical specialists with significant experience in database and systems management, seismic data processing, petrophysical analysis and geologic modeling and inversion. In our efforts to attract and retain explorationists and technical specialists, we offer an entrepreneurial culture, an extensive 3-D seismic database, state-of-the-art computer-aided exploration technology and other technical tools.

Sustain a balanced, diversified exploration effort while maintaining a low debt-to-capitalization ratio. We believe that our 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 prospects and higher-risk, higher-potential prospects.

We generally retain larger working interests in prospects located in water depths of less than 2,000 feet. The combination of larger working interests and our technical expertise has allowed us 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.

The broad coverage of the Gulf of Mexico by our 3-D seismic data allows us to participate in a variety of geologically diverse exploration opportunities and to create a diversified prospect portfolio. We are transitioning our operations to more exploration activities in the deep water of the Gulf of Mexico where operations are more difficult and costly than in shallower water. We intend to manage our exposure in deepwater exploration activities by focusing on prospects where commercial feasibility of a prospect can be evaluated with a small number of wells and where we believe 3-D seismic analysis provides attractive risk/reward benefits. We also strive to diversify our 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.

We believe that maintaining continuity in our 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, we can potentially take advantage of reduced competition for prospects and lower drilling and other oilfield service costs during periods of low oil and gas prices. Our emphasis on maintaining a lower debt-to-capitalization ratio than many of our peers has enhanced our ability and provided the flexibility to pursue this strategy.

Seismic Data Agreements

Data Covered by Seismic Data Agreements

Our initial data agreement with PGS provided us with a minimum of approximately 3,700 blocks of 3-D seismic data, and we subsequently acquired approximately 700 additional blocks under this agreement with PGS. In addition, we have also acquired approximately 17,200 blocks of standard and enhanced 3-D seismic data from various seismic contractors. Our 3-D seismic database included a total of approximately 9,700 blocks of standard data and 11,900 blocks of enhanced data as of December 31, 2004.

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 we are entitled to use is multi-client seismic data. Some of our 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, we may use the multi-client data from seismic contractors as follows:

- for our internal needs, including using the data in connection with the drilling of wells or the acquiring of interests in oil and gas properties;
- to make maps and other work products from the data;
- to make the data and work product available to our 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 our 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 we receive under any data agreement remains the property of that seismic contractor subject to the rights granted to us in the data agreement.

Restrictions on Transfer and Assignment

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

Termination Events

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

- we transfer data or our rights under the data agreement in violation of the data agreement;
- a competitor of the seismic contractor acquires control of us;
- a second major customer of the seismic contractor acquires control of us after an initial major customer of the seismic contractor has previously acquired control of us;
- we knowingly breach one of the provisions of the data agreement relating to the use, transfer or disclosure of the data;
- we unknowingly breach one of the previously mentioned provisions of the data agreement and we fail to diligently prevent a subsequent breach after we receive notice of the first breach;
- we commit a material breach of one of the other provisions of the data agreement and fail to remedy the breach after notice to us; or
- we commence a voluntary bankruptcy or similar proceeding or an involuntary bankruptcy or similar proceeding is commenced against us 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 oil and gas 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.

We have invested extensively in the advanced computer hardware and software necessary for 3-D seismic exploration. Our 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

We sell our oil and gas production under fixed and floating market price contracts each month. Revenues, profitability, cash flow and future growth depend substantially on prevailing oil and gas prices. The prices we receive for our oil and gas production fluctuate widely. Both oil and gas prices have increased significantly as compared to prior years. Among the factors that can cause these fluctuations 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 supplies of oil and gas, the price of foreign imports and overall economic conditions.

Decreases in oil and gas prices could adversely affect the carrying value of our proved reserves and revenues, profitability and cash flow. Although we did not experience any significant involuntary curtailment of oil or gas production in 2004, market, economic and regulatory factors may in the future materially affect our ability to sell our oil and gas production.

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

For the year ended December 31, 2004, sales to Cinergy Marketing & Trading, LP, Shell Trading (US) Company and Sequent Energy Management, L.P. accounted for approximately 50%, 22% and 16%, respectively, of total oil and gas revenues, excluding the effects of hedging activities. For the year ended December 31, 2003, sales to Cinergy Marketing & Trading, LP, Sequent Energy Management, L.P., Shell Trading (US) Company and Duke Energy Trade and Marketing LLC accounted for approximately 41%, 22%, 14% and 10%, respectively, of total oil and gas revenues, excluding the effects of hedging activities. 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 total oil and gas revenues, excluding the effects of hedging activities.

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and gas prices and to achieve more predictable cash flow. However, these contracts limit the benefits we would realize if prices increase. These financial arrangements take the form of swap contracts or cashless collars and are placed with major trading counterparties we believe represent minimal credit risks. We cannot provide assurance that these trading counterparties will not become credit risks in the future. Under our current hedging policy, we generally do not hedge more than 66⅔% of our estimated twelve-month production quantities without the prior approval of the Risk Management Committee of our Board of Directors. For further information concerning our hedging transactions, see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk."

Competition

We compete with major and independent oil and gas companies for leasehold acquisitions. We also compete for the equipment and labor required to operate and develop these properties. Considering the limited fleet of drilling rigs currently available to operate in the Gulf of Mexico, competition for contracting rigs is intense. As a result, we may experience delays in drilling our wells both on the shelf and in deep water.

Most of our 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 we can, which would adversely affect our competitive position. These competitors may be able to pay more for exploratory prospects and productive oil and gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for oil and gas prospects and to acquire additional properties in the future will depend upon our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, most of our competitors have been operating in the Gulf of Mexico and internationally for a much longer time than we have 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.

Our 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. The FERC requires interstate pipelines to provide open-access transportation on a basis that is equal for all natural gas suppliers. The FERC frequently reviews and modifies its regulations regarding the transportation of natural gas with the stated goal of fostering competition within all phases of the natural gas industry. We cannot predict what further action the FERC will take with regard to its regulations and open-access policies, nor can we accurately predict whether the FERC's actions will achieve the goal of increasing competition in markets in which natural gas is sold. However, we do not believe that any action taken will affect us 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. There are currently no regulations implemented by the FERC under its OCSLA authority on gatherers and other non-jurisdictional entities.

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 our operations is located on federal oil and gas leases, which are administered by the Minerals Management Service ("MMS"). Such leases are issued by the MMS 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 financial 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. We are currently in compliance with the bonding requirements of the MMS. Under some circumstances, the MMS may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially adversely affect our financial condition and results of operations.

In 2000, the MMS issued a final rule that governs the calculation of royalties and the valuation of crude oil produced from federal leases. That rule amended 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. On May 5, 2004, the MMS issued a final rule that changed certain components of its valuation procedures for the calculation of royalties owed for crude oil sales. The changes include changing the valuation basis for transactions not at arm's-length from spot to New York Mercantile Exchange ("NYMEX") prices adjusted for locality and quality differentials, and clarifying the treatment of transactions under a joint operating agreement. We believe that the changes will not have a material impact on our financial condition, liquidity or results of operations.

State and Local Regulation of Drilling and Production

We own interests in properties located in the state waters of the Gulf of Mexico offshore Texas and may conduct operations in the state waters offshore Louisiana and Mississippi in the future. 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 oil and gas properties and establishment of maximum rates of production from oil and gas wells. Some states prorate production to the market demand for oil and gas.

Oil Price Controls and Transportation Rates

Our sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at market prices. The price we receive 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 most interstate transportation rates by which adjustments are made annually based on changes to the Producer Price Index for Finished Goods, subject to certain conditions and limitations. 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. We are unable at this time to predict the effects of these regulations, if any, on the transportation costs associated with oil production from our properties. However, we do not believe that these regulations affect us any differently than other producers.

Environmental Regulations

Our 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 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 oil and gas industry in general and the offshore drilling industry in particular, our 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. 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. We are in compliance with our financial assurance obligations.

We are 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, pursuant to the OCSLA, the MMS has issued regulations relating to safety and environmental protection applicable to lessees and permittees operating on the Outer Continental Shelf. Such regulations authorize the MMS to restrict the rate of drilling fluid discharge, prescribe alternative discharge methods and restrict the use of certain components if necessary to prevent unreasonable degradation to the marine environment. Additionally, specific design and operational standards 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 orders 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.

Our 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 our operations. We do not believe that our operations would be materially affected by any such requirements, nor do we expect such requirements to be any more burdensome to us than to other companies of our size involved in oil and gas exploration and production activities.

Our management believes that we are 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 our results of operations.

Operating Hazards and Insurance

The oil and gas 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, we 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 our operations and repairs to resume operations. If we experience any of these problems, it could affect well bores, platforms, gathering systems and processing facilities, which could adversely affect our ability to conduct operations.

As part of our strategy, we explore for oil and gas in the deep water of the Gulf of Mexico where operations are more difficult than in shallower water. Our deepwater drilling and operations require the application of recently developed technologies that involve a higher risk of mechanical failure. Furthermore, the deep water of the Gulf of Mexico lacks the physical and oilfield service infrastructure present in the shallower water. As a result, our deepwater operations may require a significant amount of time between a discovery and the time that we can market the oil or gas, 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, we 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, we maintain insurance against some, but not all, potential risks and losses. Management reviews our insurance coverage at least annually. For some risks, we may not obtain insurance if we believe that 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 us.

Employees

At December 31, 2004, we had 78 full-time employees. We believe that we maintain excellent relationships with our employees. None of our employees is covered by a collective bargaining agreement. From time to time, we use 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 us, including pumping, maintenance, dispatching, inspection and testing.

Available Information

Our annual reports 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 Securities and Exchange Commission ("Commission") pursuant to Section 13(a) or 15(d) of the Exchange Act are made available, free of charge, on our internet website at www.spinnakerexploration.com as soon as reasonably practicable after we electronically file or furnish such material with or to the Commission. The public may also read and copy any materials that we file with the Commission at the Commission's Public Reference Room at 450 Fifth Street, NW, Washington, DC 20549.

Our Board of Directors has adopted Corporate Governance Guidelines, a Code of Business Conduct and Ethics, a Financial Code of Ethics and charters for our Audit, Compensation and Nominating/Corporate

Governance Committees. Each of these documents is available on our internet website at www.spinnakerexploration.com and available in print, free of charge, upon written request to Spinnaker Exploration Company, 1200 Smith Street, Suite 800, Houston, Texas 77002, Attention: Corporate Secretary.

Item 2. *Properties*

Since inception, we have concentrated on the exploration for oil and gas in the Gulf of Mexico. As of December 31, 2004, proved reserves associated with our discoveries were located on 45 different blocks, including one property in which we have only a royalty interest, with production established from 39 blocks. We have operated 54 of our 104 discoveries since inception through December 31, 2004, and our working interests in these wells range from 12.5% to 100%. Eight blocks account for approximately 76% of our total proved reserves.

As of December 31, 2004, we owned licenses to approximately 21,600 blocks of mostly contiguous 3-D seismic data in the Gulf of Mexico. This database covers an area of approximately 46 million acres, which we believe 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, 2004, we had 329 leasehold interests located in federal and Texas state waters of the Gulf of Mexico covering approximately 1,593,000 gross and 906,000 net acres. Most of these leasehold interests were acquired through a competitive bid process at federal and state lease sales.

Oil and Gas Reserves

The following table presents estimated net proved oil and gas reserves and the related net present value of the reserves as of December 31, 2004 as prepared by Ryder Scott. 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 oil and gas reserves we own. 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, 2004 were determined using prices of $6.38 per Mcf of natural gas and $37.25 per barrel of oil as of December 31, 2004.

	Proved Reserves		
	Developed	Undeveloped	Total
Natural gas (MMcf)	59,717	86,848	146,565
Oil and condensate (MBbls)	7,631	19,062	26,693
Total proved reserves (MMcfe)	105,500	201,222	306,722
Present value of future net cash flows (before income taxes) discounted at 10% (in thousands)(1)	$444,450	$601,493	$1,045,943
Standardized measure of discounted future net cash flows (in thousands)(1)	$334,668	$452,921	$ 787,589

(1) Excludes net pre-tax unrealized gain of $1.2 million for the effects of hedging activities using oil and gas prices in effect as of December 31, 2004.

The process of estimating oil and gas reserves is complex. Ryder Scott prepares our reserve estimates as of June 30 and December 31 each year. In order to assist in the preparation of these estimates, we must project production rates and timing of development expenditures. We 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 oil and gas prices, drilling and operating expenses, capital expenditures, taxes and the availability of funds. Therefore, estimates of oil and gas reserves are inherently imprecise.

Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control. As of December 31, 2004, approximately 78% of our 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.

As of December 31, 2004, approximately 66% of our proved reserves were undeveloped and primarily related to Front Runner. We anticipate that a substantial percentage of our proved undeveloped reserves at Front Runner, although not all, will be re-categorized as proved developed reserves in 2005 as several of the eight existing non-producing wells in the Front Runner field are completed and commence production. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make these capital expenditures. Although we estimate our 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 from our proved reserves is the current market value of our estimated oil and gas reserves. In accordance with Commission requirements, we base 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 of future net cash flows estimate.

Volumes, Prices and Operating Expenses

The following table presents information regarding production volumes, average sales prices and average production costs associated with our oil and gas sales for the years indicated:

	Year Ended December 31, 2004	2003	2002
Production:			
Natural gas (MMcf)	35,729	40,527	45,180
Oil and condensate (MBbls)	1,743	1,414	1,040
Total (MMcfe)	46,188	49,010	51,419
Average sales price per unit:			
Natural gas revenues from production (per Mcf)	$ 5.92	$ 5.46	$ 3.46
Effects of hedging activities (per Mcf)	(0.19)	(0.93)	0.10
Average realized price (per Mcf)	$ 5.73	$ 4.53	$ 3.56
Oil and condensate revenues from production (per Bbl)	$ 39.45	$ 30.56	$ 26.39
Effects of hedging activities (per Bbl)	(0.39)	—	—
Average realized price (per Bbl)	$ 39.06	$ 30.56	$ 26.39
Total revenues from production (per Mcfe)	$ 6.07	$ 5.39	$ 3.57
Effects of hedging activities (per Mcfe)	(0.16)	(0.77)	0.09
Total average realized price (per Mcfe)	$ 5.91	$ 4.62	$ 3.66
Expenses (per Mcfe):			
Lease operating expenses (1)	$ 0.53	$ 0.46	$ 0.35
Depreciation, depletion and amortization—oil and gas properties	$ 3.09	$ 2.56	$ 2.12

(1) The lease operating expense rate per Mcfe includes $0.01, $0.06 and $0.03 associated with workovers in 2004, 2003 and 2002, respectively.

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

The following table presents information regarding our 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, and geological and geophysical service costs. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities, pipelines and the costs related to the retirement of these assets.

	Year Ended December 31,		
	2004	2003	2002
Acquisition costs:			
Unproved	$ 15,915	$ 20,067	$ 39,789
Proved	—	—	—
Exploration costs	150,062	104,362	166,382
Development costs(1)	99,275	181,486	139,368
Total costs incurred	$265,252	$305,915	$345,539

(1) Development costs include asset retirement costs of $6.5 million and $30.0 million in 2004 and 2003, respectively, and gain on settlement of asset retirement obligations of $0.1 million and $0.5 million in 2004 and 2003, respectively.

Drilling Activity

The following table shows our drilling activity. In the table, "gross" refers to the total wells in which we have a working interest and "net" refers to gross wells multiplied by our working interest in such wells.

	Year Ended December 31,					
	2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive	11	3.4	15	9.4	11	5.1
Nonproductive	12	4.3	8	3.4	11	6.2
Total	23	7.7	23	12.8	22	11.3
Development Wells:						
Productive	3	0.7	5	2.1	3	2.0
Nonproductive	1	0.5	1	0.7	1	0.4
Total	4	1.2	6	2.8	4	2.4

As of March 10, 2005, the Company was drilling four gross (2.0 net) exploratory wells in the Gulf of Mexico and one gross (0.1 net) exploratory well in West Africa.

Productive Wells

The following table sets forth the number of productive oil and gas wells in which we owned an interest as of December 31, 2004:

	Total Productive Wells	
	Gross	Net
Natural gas	80	40.9
Oil	24	9.9
Total	104	50.8

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 oil and gas regardless of whether or not such acreage contains proved reserves. Our developed and undeveloped lease acreage as of December 31, 2004 was as follows (in thousands):

	Developed Acreage		Undeveloped Acreage		Total	
	Gross	Net	Gross	Net	Gross	Net
Federal Waters Offshore Louisiana	143	63	822	439	965	502
Federal Waters Offshore Texas	83	49	526	347	609	396
Texas State Waters	12	5	7	3	19	8
Total	238	117	1,355	789	1,593	906

Our 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 water of the Gulf of Mexico. Excluding lease acreage held by production, average remaining lease terms were 4.9 years, 3.7 years and 0.9 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, we may be a party to various legal proceedings. We currently are not a party to any litigation that we consider material based upon the facts and circumstances as they are known at this time.

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

We did not hold a meeting of stockholders or otherwise submit any matter to a vote of stockholders in the fourth quarter of 2004.

PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Our 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 our common stock for each quarter by period.

	Sales Price	
	High	**Low**
2003:		
First Quarter	$22.70	$17.15
Second Quarter	$28.01	$18.01
Third Quarter	$26.50	$19.98
Fourth Quarter	$33.52	$23.97
2004:		
First Quarter	$36.99	$31.93
Second Quarter	$39.50	$30.80
Third Quarter	$40.60	$31.07
Fourth Quarter	$37.00	$30.65
2005:		
First Quarter (through March 11, 2005)	$39.30	$31.50

On March 11, 2005, the closing sale price of our common stock, as reported by the New York Stock Exchange, was $35.56 per share. On March 11, 2005, there were 28 holders of record.

We have never declared or paid any dividends on our common stock. We currently intend to retain future earnings, if any, for the operation and development of our business and do not anticipate paying any dividends on our common stock in the foreseeable future. In addition, our $200.0 million revolving credit agreement dated as of December 19, 2003 and amended as of February 8, 2005 (the "Revolver") contains restrictions and limitations on paying cash dividends on our common stock. For a description of the covenants and restrictive provisions of the Revolver, 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 incorporated by reference herein from Spinnaker's Definitive Proxy Statement for our 2005 Annual Meeting of Stockholders, when filed pursuant to Regulation 14A under the Securities Exchange Act of 1934.

Item 6. *Selected Financial Data*

The following table sets forth some of our 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 our future results of operations or financial performance.

	Year Ended December 31,				
	2004	2003	2002	2001	2000
	(In thousands, except per share data)				
Statement of Operations Data:					
Revenues	$ 272,888	$226,850	$188,326	$210,376	$121,383
Expenses:					
Lease operating expenses	24,633	22,489	18,212	12,132	9,009
Depreciation, depletion and amortization—oil and gas properties	142,913	125,331	108,998	85,059	47,451
Depreciation and amortization—other	1,353	1,310	914	398	309
Accretion expense(1)	3,054	2,251	—	—	—
Gain on settlement of asset retirement obligations(1)	(133)	(464)	—	—	—
General and administrative	15,787	12,773	10,984	9,443	7,350
Charges related to Enron bankruptcy(2)	—	—	128	3,059	—
Total expenses	187,607	163,690	139,236	110,091	64,119
Income from operations	85,281	63,160	49,090	100,285	57,264
Other income (expense):					
Interest income	195	201	1,014	3,574	2,908
Interest expense, net	(1,206)	(784)	(762)	(381)	(748)
Other	—	140	—	—	—
Total other income (expense)	(1,011)	(443)	252	3,193	2,160
Income before income taxes	84,270	62,717	49,342	103,478	59,424
Income tax expense	30,337	22,578	17,763	37,252	20,858
Income before cumulative effect of change in accounting principle	53,933	40,139	31,579	66,226	38,566
Cumulative effect of change in accounting principle(1)	—	(3,527)	—	—	—
Net income	$ 53,933	$ 36,612	$ 31,579	$ 66,226	$ 38,566
Basic income per common share:					
Income before cumulative effect of change in accounting principle	$ 1.60	$ 1.21	$ 1.00	$ 2.45	$ 1.70
Cumulative effect of change in accounting principle(1)	—	(0.11)	—	—	—
Net income per common share	$ 1.60	$ 1.10	$ 1.00	$ 2.45	$ 1.70
Diluted income per common share:					
Income before cumulative effect of change in accounting principle	$ 1.55	$ 1.18	$ 0.97	$ 2.34	$ 1.61
Cumulative effect of change in accounting principle(1)	—	(0.10)	—	—	—
Net income per common share	$ 1.55	$ 1.08	$ 0.97	$ 2.34	$ 1.61
Weighted average number of common shares outstanding(3):					
Basic	33,771	33,234	31,695	27,079	22,679
Diluted	34,807	33,880	32,653	28,360	24,011
Summary Balance Sheet Data:					
Working capital (deficit)	$ (13,514)	$ (33,168)	$ (6,359)	$ (20,654)	$ 74,005
Property and equipment, net(1)	1,061,137	939,668	760,854	522,573	304,381
Total assets	1,150,931	990,582	842,715	587,316	442,704
Total long-term debt	105,000	50,000	—	—	—
Total equity(3)	814,086	744,061	692,977	458,492	361,259

(1) Effective January 1, 2003, we adopted Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 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. As of January 1, 2003, we recorded asset retirement costs of $21.4 million and asset retirement obligations of $26.0 million. The cumulative effect of change in accounting principle was $3.5 million, net of taxes of $2.0 million.

Accretion expense is the recognition of period-to-period changes in the asset retirement obligation liability resulting from the passage of time, subsequent to the initial asset retirement obligation liability measurement.

Gain on settlement of asset retirement obligations represents the difference between the actual cost of the asset retirement and the asset retirement obligation.

(2) We 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. We 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. We recorded a reserve of $3.2 million for our share of these receivables.

(3) 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.

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

Executive Overview

Our primary objective since inception has been to assemble a large 3-D seismic database and focus on exploration activities in the Gulf of Mexico because we believe that this area represents one of the most attractive exploration regions in North America. We also believe that a geographic focus provides an excellent opportunity to develop and maintain competitive advantages through our regional exploration and operating expertise. We try to maintain balance and diversity in our exploration approach by drilling both shallow water and deepwater prospects, ranging from lower-risk prospects to higher-risk, higher-potential prospects. We have also evaluated onshore and offshore opportunities outside the Gulf of Mexico in the past. In order to diversify our operations and apply our skill set to other opportunities, we entered into a farm-out agreement in December 2004 covering a 12.5% interest in OPL Block 256 offshore Nigeria from Devon. The transfer of interest is pending various approvals within the Nigerian government. This opportunity gives us exposure to a large acreage position that contains multiple prospects in a prolific basin. We expect our capital requirements for exploratory activities in connection with this venture to be approximately $50 million to $60 million over a two to three year period beginning in the first quarter of 2005.

We recognized 2004 net income of $53.9 million, or $1.55 per diluted share, compared to 2003 net income of $36.6 million, or $1.08 per diluted share. These financial results were impacted by a $30.2 million decrease in hedging losses and a 13% higher average commodity price, partially offset by the impact of 6% lower production. The lease operating expense rate per Mcfe increased 15% in 2004, primarily due to higher operating rates associated with new wells that commenced production in 2003 and 2004. The DD&A expense rate per Mcfe increased 21% in 2004, primarily due to unsuccessful drilling operations, a net downward revision to proved reserves and higher finding costs associated with certain discoveries in 2004. We had $21.8 million in cash and cash equivalents and outstanding borrowings of $105.0 million under the Revolver as of December 31, 2004.

We have experienced and expect to continue to experience substantial capital requirements. We incurred capital costs of approximately $920.0 million in the past three years. Additionally, we have had negative working capital at the end of each of the last three years. Our working capital deficit was $13.5 million as of

December 31, 2004 compared to a deficit of $33.2 million as of December 31, 2003. We have capital expenditure plans for 2005 totaling approximately $280.0 million. We believe that cash flows from operations, proceeds from available borrowings under the Revolver and Front Runner spar production facility financing opportunities will be sufficient to meet our capital requirements in the next twelve months.

Production of 46.2 Bcfe in 2004 was down 6% from 2003 production of 49.0 Bcfe. Proved oil and gas reserves of 306.7 Bcfe as of December 31, 2004 were down 8% from December 31, 2003 proved reserves of 332.6 Bcfe. Although we have been able to maintain a drilling success rate of approximately 60% since inception, our exploratory drilling successes on the shelf and deep shelf since the second half of 2001 have been smaller and had less impact on our operating results than those prior to that time, resulting in a negative impact on our subsequent production and reserve growth. Additionally, several of our discoveries since mid-2001 were in the deep water at Front Runner, and we do not expect to see the full impact on production from this project until the second half of 2005.

Production

Since inception, 88% of our total production has been natural gas, including 77% in 2004. Considering oil and condensate production from deepwater projects in 2005, we anticipate that this concentration in natural gas production will decrease to approximately one-half of total production in 2005. As a result, our revenues, profitability and cash flows will be less sensitive to natural gas prices and more sensitive to oil prices.

Generally, our producing properties on the shelf have high initial production rates followed by steep declines. As a result, we must continually drill for and develop new oil and gas reserves on the shelf and in deep water to replace those being depleted by production. Substantial capital expenditures are required to find and develop these reserves. Our challenge is to find and develop reserves at economic rates and commence production of these reserves as quickly and efficiently as possible. Our production growth in the near term is dependent upon the success of our shelf drilling activities since large deepwater development projects require significantly more time before production commences.

Drilling Activities and Oil and Gas Property Costs

From inception through December 31, 2004, we participated in drilling 176 wells in the Gulf of Mexico resulting in 104 discoveries. Historically, most of the wells we drilled were on the shelf. However, we are in the process of transitioning to more deepwater operations. Prior to 2001, we drilled nine deepwater wells, three of which were successful. Since 2001, we have drilled 32 deepwater wells, 21 of which were successful. In 2005, we expect to drill approximately nine additional deepwater wells in the Gulf of Mexico and two deepwater wells in West Africa. Our most significant deepwater projects include oil discoveries at Front Runner and natural gas discoveries at the Eastern Gulf Project. Front Runner commenced production in December 2004 from the first of nine wells. We anticipate that additional wells will be completed in 2005 until the Front Runner spar production facility reaches its estimated full oil capacity of 60,000 barrels per day. The Eastern Gulf Project development plan is complete. The fields will be developed via subsea tieback to a floating production facility located in Mississippi Canyon 920 that will be capable of processing 850 MMcf of natural gas per day. We anticipate first production from the Eastern Gulf Project in 2007.

We participated in 14 successful wells in 27 attempts in 2004. Capital costs incurred totaled $265.7 million in 2004, including approximately $15.9 million for leasehold and other acquisition activities, $150.1 million for exploration activities, $99.3 million for development activities and $0.4 million for acquisitions of other property and equipment.

Our current capital expenditure budget for 2005 is approximately $280.0 million, including $190.0 million for exploration activities and geological and geophysical expenditures, $45.0 million for development activities, $41.0 million for leasehold acquisitions and $4.0 million for other property and equipment. We currently plan to drill approximately 21 wells in 2005, including ten wells on the Gulf of Mexico shelf, nine wells in the deep economically produce. Natural gas prices have been extremely volatile recently as a result of various factors, including weather, industrial demand and uncertainty related to the ability of the energy industry to provide supply to meet future demand. There are questions whether fundamentals support current natural gas prices.

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and gas prices and to achieve more predictable cash flow. However, these contracts limit the benefits we would realize if prices increase. We recorded a net hedging loss of $40.6 million from 2002 through 2004, including a net hedging loss of $7.5 million in 2004. Major challenges related to our hedging activities include a determination of the proper production volumes to hedge and acceptable commodity price levels for each hedge transaction.

Revenues, profitability, cash flow and future growth depend substantially on prevailing oil and gas prices and our ability to find and develop oil and gas reserves that are economically recoverable. A substantial or extended decline in the prices for oil and gas could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and gas reserves that may be economically produced and access to capital.

Critical Accounting Policies

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us 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 DD&A of proved oil and gas properties. Oil and gas 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. Our critical accounting policies are as follows:

Full Cost Method of Accounting

The accounting for oil and gas exploration and production is subject to special accounting rules that are specific to the industry. Two allowable methods exist for these activities: the successful efforts method and the full cost method. Several significant differences exist between the two methods. The major difference is under the successful efforts method, costs such as geological and geophysical, exploratory dry holes and delay rentals are expensed as incurred whereas under the full cost method, these types of charges are capitalized into the full cost amortization base.

We use the full cost method of accounting for investments in oil and gas properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs incurred for the purpose of exploring for and developing oil and gas properties, 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, and geological and geophysical service costs. Development costs include the costs of drilling development wells, completions, platforms, facilities, pipelines and the costs related to the retirement of these assets. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of oil and gas 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 oil and gas reserves.

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. Although some of these costs will ultimately result in no additional proved reserves, we water of the Gulf of Mexico and two wells in West Africa. Exploration and development activities in deep water require significant capital commitments. If we are successful in our exploration efforts in 2005, currently budgeted capital requirements in 2005 will increase.

Finding and Development Costs

We believe that the DD&A rate is the best measure for evaluating finding and development costs per Mcfe since the rate generally considers all acquisition, exploration and development costs. The rate also considers any additional development costs associated with proved reserves, such as costs for drilling new wells, sidetracks and recompletions, which we will incur in the future to produce the oil and gas reserves and an estimate of the costs to abandon wells, platforms, facilities and pipelines after reservoirs are depleted. However, other factors must also be considered when relying on the DD&A rate as a measure for evaluating a company's finding and development costs per Mcfe. In most cases, the total estimated resource of a reservoir is not usually proved with only one well, and the initial proved reserves are generally burdened with 100% of the development costs as well as any future development costs. In addition, the costs of successful wells may in some instances impact the DD&A rate before associated proved reserves are booked.

The DD&A rate per Mcfe is calculated quarterly and increased 28% to $3.43 in the fourth quarter of 2004 from $2.68 in the fourth quarter of 2003. The DD&A rate increased 21% to $3.09 in 2004 from $2.56 in 2003. The increase in the DD&A rate was primarily due to costs of $83.6 million associated with 13 unsuccessful wells in 2004, a net downward revision to proved reserves of 20.4 Bcfe and higher finding costs associated with new discoveries in 2004 due primarily to the timing of reserve recognition.

Proved Oil and Gas Reserves

We have achieved reserve growth through exploration activities and have not acquired any reserves through acquisition activities. As of December 31, 2004, Ryder Scott estimated net proved reserves at approximately 306.7 Bcfe, with a present value of future net cash flows (before income taxes) of approximately $1.046 billion. Proved reserves are down 8% from the end of 2003. Proved oil and condensate reserves were 52% of total proved reserves and proved undeveloped reserves were approximately 66% of total proved reserves as of December 31, 2004. Front Runner represented approximately 67% of our total proved undeveloped reserves. Our 2004 proved reserve additions totaled approximately 40.8 Bcfe, offset in part by a net downward revision of 20.4 Bcfe.

Of the 20.4 Bcfe net downward reserve revision, 14.3 Bcfe, or 70%, related to the retraction of royalty suspension volumes at Front Runner. The MMS allows royalty relief under the Deep Water Royalty Relief Act subject to certain oil and gas price thresholds on eligible leases in the Gulf of Mexico. Front Runner area reserves are subject to royalty relief on the first 87.5 million equivalent barrels of oil produced. If the average annual NYMEX oil and gas prices exceed the price thresholds, royalty suspension volumes are retracted in that year. Average oil and gas prices have exceeded these thresholds in recent years and in 2004 for certain leases.

At the end of each period, reserves are estimated based on oil and gas prices then in effect. Prior to June 30, 2004, our share of gross Front Runner reserves excluded natural gas royalty suspension volumes and included oil royalty suspension volumes. Based on the average oil price as of June 30, 2004, we believed that the thresholds would be exceeded and the leases would not qualify for royalty relief. As a result, we incurred a downward reserve revision of approximately 2.4 million barrels, or 14.3 Bcfe, in the second quarter of 2004. The remaining net downward reserve revision was 6.1 Bcfe. No downward reserve revision on any individual property exceeded 4% of proved reserves as of December 31, 2003.

Oil and Gas Prices and Hedging Activities

Oil and gas prices fluctuate widely, primarily affecting the amount of cash flow available for capital expenditures, our ability to borrow and raise additional capital and the amount of oil and gas that we can expect the benefits of successful wells to more than offset the costs of any unsuccessful ones. As a result, we believe that the full cost method of accounting better reflects the true economics of exploring for and developing oil and gas reserves. Our financial position and results of operations would have been significantly different had we used the successful efforts method of accounting for our oil and gas investments.

Proved Reserve Estimates

Ryder Scott prepares estimates of our proved oil and gas reserves as of June 30 and December 31 each year. These estimates of proved reserves are based on the quantities of oil and gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. For example, we must estimate, among others, the amount and timing of future production, operating, workover and transportation expenses and development and abandonment costs, all of which may vary considerably from actual results. In addition, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Any significant variance in these assumptions could materially affect the estimated quantity and value of our oil and gas reserves.

Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements. For example, we use the unit-of-production method to amortize our oil and gas properties and the quantity of reserves could significantly impact our DD&A rate and related expense. Our oil and gas properties are also subject to a ceiling limitation based in part on the quantity of our proved reserves. Finally, these proved reserves are the basis for our supplemental oil and gas disclosures.

Depreciation, Depletion & Amortization

DD&A expense is comprised of many factors, including costs incurred in the acquisition, exploration and development of proved oil and gas reserves, production levels, estimates of proved reserve quantities and future development and abandonment costs. We compute the provision for DD&A of oil and gas properties on a quarterly basis using the unit-of-production method. The calculation is based on quarterly production and estimates of proved reserves. Unevaluated 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 and estimated salvage values of platforms and other equipment associated with future asset retirement obligations.

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, 2004, we excluded from the amortization base estimated future expenditures of $27.9 million associated with common development costs for our 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 $27.9 million had been included in the amortization base as of December 31, 2004, and no additional reserves were assigned to the Front Runner project, the DD&A rate would have been $3.12 per Mcfe, or an increase of $0.03 over the actual 2004 DD&A rate of $3.09 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 oil and gas reserves used in the full cost ceiling calculation.

Full Cost Ceiling

Under full cost accounting rules, total capitalized costs are limited to a ceiling equal to the present value of future net cash flows from proved oil and gas reserves, discounted at 10% per annum, plus the lower of cost or fair value of unproved properties less income tax effects (the "ceiling limitation"). We perform a quarterly ceiling test to determine whether the net book value of our full cost amortization base exceeds the ceiling limitation. If capitalized costs, net of accumulated DD&A, less related deferred taxes are greater than the ceiling limitation, a write-down or impairment of the full cost amortization base is required. A write-down of the carrying value of oil and gas properties is a non-cash charge that reduces earnings and typically results in lower DD&A expense in future periods.

In accordance with Commission guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. In addition, subsequent to the adoption of SFAS No. 143, the future cash outflows associated with the settlement of asset retirement obligations are not included in the computation of the discounted present value of future net cash flows for the purposes of the ceiling test calculation.

In calculating our ceiling test as of December 31, 2004, we estimated a full cost ceiling "cushion" of $128.3 million, using prices of $6.38 per Mcf of natural gas and $37.25 per barrel of oil and condensate. Considering the volatility of oil and gas prices, it is probable that our estimate of discounted future net cash flows from proved oil and gas reserves will change in the near term. If oil and gas prices decline, even if for only a short period of time, if we incur significant costs associated with unsuccessful drilling operations or if we have downward revisions to our estimated proved reserves, it is possible that write-downs of oil and gas properties could occur in the future.

Unproved Properties

The costs associated with unproved properties and properties under development are not initially included in the amortization base and primarily relate to unevaluated leasehold costs, delay rentals, geological and geophysical costs, wells in-progress and wells pending determination.

Geological and geophysical costs, including 3-D seismic data costs and related seismic hardware and software costs, are included in the full cost amortization base as incurred when such costs cannot be associated with specific unevaluated properties for which we own a direct interest. Seismic data costs are associated with specific unevaluated properties if the seismic data may be used to evaluate acreage that is covered by a leasehold interest owned by Spinnaker. We make this determination based on an analysis of leasehold and seismic maps and discussions with our management and exploration managers. Seismic hardware and software costs are associated with specific unevaluated properties if the hardware and software was acquired specifically to process or reprocess certain 3-D seismic data that covers an area or trend containing a leasehold interest owned by Spinnaker. We make this determination based on discussions with our management and information technology and seismic processing specialists. When such seismic data, hardware and software costs can be associated with specific unevaluated properties and excluded from the full cost amortization base, we allocate the costs based on management's judgment of the potential economic value to be realized upon determination of whether or not proved reserves can be assigned to the properties. Significant assumptions used by management in determining the potential economic value of an owned leasehold interest include the number of successful and unsuccessful wells drilled within and around the lease and trend, the number of prospects on the lease and the size of the potential resource associated with the lease.

Unevaluated leasehold costs, delay rentals and geological and geophysical costs associated with specific properties are transferred to the amortization base either upon determination of whether or not proved reserves can be assigned to the properties or if impairment has occurred. The costs of drilling exploratory dry holes are transferred to the amortization base immediately upon determination that the well is unsuccessful. The costs associated with wells in-progress and wells pending determination are transferred to the amortization base upon determination of whether or not proved reserves can be assigned to the properties.

Leasehold Costs

In September 2004, the Financial Accounting Standards Board ("FASB") issued FASB Staff Position ("FSP") No. FAS 142-2, "Application of FASB Statement No. 142, Goodwill and Other Intangible Assets to Oil and Gas Producing Entities." This FSP confirms that SFAS No. 142 did not change the balance sheet classification or disclosure requirements for drilling and mineral rights of oil and gas producing entities. We classify the costs of oil and gas drilling and mineral rights as property and equipment.

Asset Retirement Obligations

We recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying amount of the asset. The fair value of a liability for an asset retirement obligation is the amount which that liability could be settled in a current transaction between willing parties. Spinnaker uses the expected cash flow approach for calculating asset retirement obligations. The liability is discounted using the credit-adjusted risk-free interest rate in effect when the liability is initially recognized. The changes in the liability for an asset retirement obligation due to the passage of time are measured by applying an interest method of allocation to the amount of the liability at the beginning of the period. This amount is recognized as an increase in the carrying amount of the liability and as accretion expense classified as an operating item in the statement of operations.

Financial Instruments and Price Risk Management Activities

At December 31, 2004, our 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. We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and gas 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. We recorded net hedging losses of $7.5 million and $37.7 million and a net hedging gain of $4.7 million in 2004, 2003 and 2002, respectively.

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. We elected 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 and $0.2 million in 2004, 2003 and 2002, respectively. For further information concerning SFAS 123 see Note 2 of the Notes to Consolidated Financial Statements.

New Accounting Pronouncements

On September 28, 2004, the Commission released Staff Accounting Bulletin ("SAB") No. 106 regarding the application of SFAS No. 143, "Accounting for Asset Retirement Obligations," by oil and gas producing companies following the full cost accounting method. Pursuant to SAB No. 106, oil and gas producing companies that have adopted SFAS No. 143 should exclude the future cash outflows associated with the settlement of asset retirement obligations from the computation of the present value of estimated future net revenues for the purposes of the full cost ceiling calculation. In addition, estimated dismantlement and abandonment costs, net of estimated salvage values, that have been capitalized should be included in the amortization base for computing DD&A. Disclosures are required to include discussion of how a company's ceiling test and DD&A calculations are impacted by the adoption of SFAS No. 143. SAB No. 106 is effective prospectively as of the beginning of the first fiscal quarter beginning after October 4, 2004. Since our adoption of SFAS No. 143 on January 1, 2003, we have calculated the ceiling test and our DD&A in accordance with the interpretations set forth in SAB No. 106; therefore, the adoption of SAB No. 106 will have no effect on our consolidated financial statements.

On December 16, 2004, the FASB revised SFAS No. 123 (revised 2004), "Share-Based Payment," ("SFAS No. 123(R)") that will require compensation costs related to share-based payment transactions to be recognized in the financial statements. With limited exceptions, the amount of compensation cost will be measured based on the grant-date fair value of the equity or liability instruments issued. In addition, liability awards will be remeasured each reporting period. Compensation cost will be recognized over the period that an employee provides service in exchange for the award. SFAS No. 123(R) replaces SFAS No. 123 and supersedes APB Opinion No. 25. For us, SFAS No. 123(R) is effective for the first quarterly reporting period after June 15, 2005. Adoption of SFAS No. 123(R) will require us to recognize compensation expense for all awards we grant after the date of adoption and for the unvested portion of all options granted that remain outstanding on the date of adoption. All options that we granted prior to June 30, 2001 will be fully vested prior to adoption of SFAS No. 123(R) and will not be considered as part of the adoption in accordance with the new standard. We are currently evaluating the effect of adopting SFAS No. 123(R).

On December 16, 2004, the FASB issued SFAS No. 153, "Exchanges of Nonmonetary Assets," an amendment of APB Opinion No. 29, to clarify the accounting for nonmonetary exchanges of similar productive assets. SFAS No. 153 eliminates the exception from the fair value measurement for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. SFAS No. 153 will be applied prospectively and is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. We do not expect the adoption of SFAS No. 153 to have a material impact on our consolidated financial statements.

Related Parties

We purchase oilfield goods, equipment and services from Baker Hughes Incorporated ("Baker Hughes"), Cooper Cameron Corporation ("Cooper Cameron"), National-Oilwell, Inc. ("National-Oilwell") and other oilfield services companies in the ordinary course of business. We incurred charges of approximately $13.5 million, $7.5 million and $16.1 million in 2004, 2003 and 2002, respectively, from affiliates of Baker Hughes. Mr. Michael E. Wiley, a director of Spinnaker, served as Chairman of the Board and Chief Executive Officer of Baker Hughes through October 25, 2004. We incurred charges of approximately $0.1 million in each of 2004, 2003 and 2002 from Cooper Cameron. Mr. Sheldon R. Erikson, a director of Spinnaker, serves as Chairman of the Board, Chief Executive Officer and President of Cooper Cameron. We incurred charges of approximately $0.1 million, $0.1 million and $0.2 million in 2004, 2003 and 2002, respectively, from National-Oilwell. Mr. Roger L. Jarvis, Chairman of the Board, Chief Executive Officer and President of Spinnaker, has served as a director of National-Oilwell since February 2002. These amounts represent less than 1% of Baker Hughes', Cooper Cameron's and National-Oilwell's total revenues in 2004, 2003 and 2002 and only reflect charges directly incurred by us. Our partners may incur charges from these related parties that are not included above.

We believe that these transactions are at arm's-length and the charges we pay 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. Each of these companies is a leader in its respective segments of the oilfield services sector. We could be at a disadvantage if we were to discontinue using these companies as vendors.

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 we use cannot eliminate exploration risk and require experienced technical personnel whom we may be unable to attract or retain.

Our future success will depend on the success of our exploratory drilling program. Exploration activities involve numerous risks, including the risk that no commercially productive oil or gas reservoirs will be discovered. In addition, we are often 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. We could incur losses as a result of expenditures on unsuccessful wells. Poor results from our exploration activities could materially and adversely affect future cash flows and results of operations.

Our exploratory drilling success will depend, in part, on our 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 we cannot retain current personnel or attract additional experienced personnel, our ability to compete in the Gulf of Mexico could be adversely affected.

A substantial portion of our proved reserves are associated with our deepwater oil discovery at Front Runner. The development of Front Runner will continue to require financial resources as additional wells are completed and remains subject to other uncertainties that could have a material impact on this discovery.

Our deepwater oil discovery at Front Runner, in which we have a 25% non-operator working interest, has required significant financial resources and will require additional expenditures as the remaining wells are completed. We have incurred $157.3 million in capital expenditures for Front Runner through December 31, 2004, and we expect to incur approximately $29.5 million in additional development costs during 2005 and $42.1 million thereafter. Because another oil and gas exploration and production company operates Front Runner, we have a limited ability to influence the operations and costs associated with this property.

Front Runner is located in approximately 3,500 feet of water. The nine wells have been drilled in the Front Runner area to total depths in excess of 20,000 feet. We have limited experience with large deepwater and deep drilling depth discoveries similar to Front Runner as most of our prior discoveries have occurred in shallower water and drilling depths. As a result of these uncertainties and risks, we may encounter difficulties and delays that could cause actual expenditures to exceed anticipated amounts.

Production from the first well commenced in December 2004. Weather and other conditions may delay the completion of the remaining wells resulting in delays in the production ramp-up schedule. In addition, Front

Runner may produce substantially less oil and gas than currently projected. Finally, we cannot predict commodity prices as the remaining wells commence production. If production is substantially less than currently projected or commodity prices are low, our results of operations and financial condition could be adversely affected.

Front Runner accounted for approximately 67% of our proved undeveloped reserves as of December 31, 2004. If the actual reserves associated with Front Runner are substantially less than the estimated reserves, our 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, our future business, financial condition and operating results will be materially and adversely affected.

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

The oil and gas business involves a variety of operating risks, including fires, explosions, blow-outs and surface cratering, uncontrollable flows of underground oil, natural gas 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, we 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 our operations and repairs to resume operations. If we experience any of these problems, it could affect well bores, platforms, gathering systems and processing facilities, which could adversely affect our 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, we 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, we may not obtain insurance if we believe 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 our operations.

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

We explore for oil and gas at deeper drilling depths and in the deep water of the Gulf of Mexico where operations are more difficult and costly than at shallower depths and in shallower water. Deep depth and deepwater drilling and operations require the application of recently developed technologies that involve a higher risk of mechanical failure. We have experienced and will continue to experience significantly higher drilling costs for deep depth and deepwater prospects.

As of December 31, 2004, approximately 97% of our proved undeveloped reserves were located in deep water and under development. The deep water lacks the physical and oilfield service infrastructure present in the shallower water. 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 we can market the oil or gas, increasing both the financial and operational risk involved with these operations.

We are vulnerable to operational, regulatory and other risks associated with the Gulf of Mexico because we have historically explored for and produced oil and gas exclusively in that area.

Our operations and revenues are impacted acutely by conditions in the Gulf of Mexico. Today, substantially all of our operations are still in the Gulf of Mexico. This concentration of activity makes us more vulnerable than many of our 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.

We expect to commence international exploration activities in 2005. Operations in areas outside the U.S. are subject to various risks inherent in international operations.

We entered into a farm-out agreement in December 2004 covering a 12.5% interest in OPL Block 256 offshore Nigeria from Devon. The transfer of interest is pending various approvals within the Nigerian government.

Operations in areas outside the U.S. are subject to various risks inherent in international operations. These risks may include, among other things, the loss of revenues, property and equipment as a result of hazards such as expropriation, war, insurrection and other political risks, increases in taxes and governmental royalties, renegotiation of contracts with governmental entities, changes in laws and policies governing operations of foreign-based companies, currency restrictions and exchange rate fluctuations and other uncertainties arising out of foreign government sovereignty over a company's international operations. International operations may also be adversely affected by laws and policies of the U.S. affecting foreign trade and taxation.

A significant part of the value of our 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 our business.

During 2004, approximately 67% of our production came from eight properties in the Gulf of Mexico. If mechanical problems, storms or other events curtailed a substantial portion of this production, our cash flow would be adversely affected. In addition, as of December 31, 2004, our proved reserves were located on 45 blocks in the Gulf of Mexico, with 76% of the proved reserves attributable to eight of these blocks. One property, Front Runner, accounted for approximately 67% of total proved undeveloped reserves and 51% of total proved reserves. If the actual reserves associated with any one of these eight properties are substantially less than the estimated reserves, our results of operations and financial condition could be adversely affected.

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. 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. We have recorded most of our proved reserves in deep water based on various advanced technical tests rather than production flow tests.

If any seismic contractor terminates its data agreement with us, our ability to find additional reserves could be impaired.

Our success depends heavily on access to 3-D seismic data. If any seismic contractor terminates its data agreement with us, we would lose access to a portion of the 3-D seismic data, which loss could have an adverse effect on our ability to find additional reserves. A seismic contractor may terminate its data agreement with us on several grounds, including if a competitor of the seismic contractor acquires control of us or if we breach 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 we 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, we may be placed at a competitive disadvantage, and competitive pressures may force us 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 we can. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. One or more of the technologies that we currently use or that we may implement in the future may become obsolete, which may adversely affect our 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 our 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 our reserves.

The process of estimating oil and gas 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—Oil and Gas Reserves."

Ryder Scott prepares our reserve estimates as of June 30 and December 31 each year. In order to assist in the preparation of these estimates, we must project production rates and timing of development expenditures. We 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 oil and gas prices, drilling and operating expenses, capital expenditures, taxes and the availability of funds. Even though our reserve estimates are prepared by an independent third party, these estimates of oil and gas reserves are still inherently imprecise.

Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, estimates of proved reserves may be adjusted to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our 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, 2004. 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 our proved reserves is the current market value of our estimated oil and gas reserves. In accordance with Commission requirements, we base 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 of future net cash flows estimate.

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

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

Relatively short rates of production for Gulf of Mexico properties compared to other producing regions of the world subject us to more active reserve replacement efforts, require us to incur capital expenditures more frequently to replace production and generate growth in reserves and may impair our ability to slow or shut-in production during periods of low prices for oil and gas.

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, our reserve replacement needs from new prospects in the Gulf of Mexico are greater and require us to incur capital expenditures more frequently to replace production than would typically be required in many other producing regions of the world.

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

Oil and gas prices fluctuate widely, and low prices could have a material adverse impact on our business and financial results.

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

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

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and gas 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 we believe represent minimum credit risks. We cannot provide assurance that these trading counterparties will not become credit risks in the future. Hedging arrangements expose us to risks in some circumstances, including situations when the other party to the hedging contract defaults on its contractual 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 in the past limited and may continue to limit the benefit we could receive from increases in the prices for oil and gas. We cannot provide assurance that the hedging transactions we have entered into, or will enter into, will adequately protect us from fluctuations in oil and gas prices. We may choose not to engage in hedging transactions in the future. As a result, we may be adversely affected during periods of declining oil and gas prices.

Our success depends on our Chief Executive Officer, Chief Operating Officer and other key personnel, the loss of whom could disrupt business operations.

We depend to a large extent on the efforts and continued employment of our Chief Executive Officer, Chief Operating Officer and other key personnel. If any of these key personnel resign or become unable to continue in their present role and if they are not adequately replaced, our business operations could be adversely affected.

We are subject to complex laws and regulations, including environmental regulations, which can adversely affect the cost, manner or feasibility of doing business.

Exploration for and development, production and sale of oil and gas 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. We 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, we could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. We do 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 our operations and subject us 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 oil and 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 our financial condition and results of operations.

Competition in the oil and gas industry is intense, and we are smaller and have a more limited operating history than most of our competitors in the Gulf of Mexico and internationally.

We compete with major and independent oil and gas companies for property acquisitions. We also compete for the equipment and labor required to operate and develop our properties. Most of our competitors have substantially greater financial and other resources than we do. 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 we can, which would adversely affect our competitive position. These competitors may be able to pay more for exploratory prospects and productive oil and gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for oil and gas prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, most of our competitors have been operating in the Gulf of Mexico and internationally for a much longer time than we have and have demonstrated the ability to operate through industry cycles.

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

Other companies operate some of the properties in which we have an interest, including Front Runner and the Eastern Gulf Project. As a result, we have a limited ability to exercise influence over operations for these properties or their associated costs. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could materially and adversely affect the realization of 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 our control, including timing and amount of capital expenditures, the operator's expertise and financial resources, approval of other participants in drilling wells and selection of technology.

We may have difficulty financing our planned growth.

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

Warburg owns a significant number of shares of our 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, 2004, Warburg owned approximately 20% of our 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 our certificate of incorporation or bylaws and the approval of mergers and other significant corporate transactions. Warburg's influence over us may delay or prevent a change of control of Spinnaker and may adversely affect the voting and other rights of other stockholders.

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

A portion of our 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 our common stock to drop significantly, even if our business is doing well.

The market price of our 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.

Our certificate of incorporation and bylaws contain provisions that could discourage an acquisition or change of control of Spinnaker.

Our certificate of incorporation authorizes our Board of Directors to issue preferred stock without stockholder approval. If our Board of Directors elects to issue preferred stock, it could be more difficult for a third party to acquire control of us, even if that change of control might be beneficial to stockholders. In addition, provisions of our 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 us.

Terrorist attacks on oil and gas production facilities, transportation systems and storage facilities could have a material adverse impact on our business.

Oil and gas production facilities, transportation systems and storage facilities could be targets of terrorist attacks. These attacks could have a material adverse impact on our results of operations and cash flows if certain oil and gas infrastructure integral to our operations were destroyed or damaged.

Results of Operations

	Year Ended December 31,				Year Ended December 31,			
	2004	2003	Variance		2003	2002	Variance	
Production:								
Natural gas (MMcf)	35,729	40,527	(4,798)	(12%)	40,527	45,180	(4,653)	(10%)
Oil and condensate (MBbls)	1,743	1,414	329	23%	1,414	1,040	374	36%
Total (MMcfe)	46,188	49,010	(2,822)	(6%)	49,010	51,419	(2,409)	(5%)
Revenues (in thousands):								
Natural gas	$211,673	$221,179	$ (9,506)	(4%)	$221,179	$156,214	$ 64,965	42%
Oil and condensate	68,769	43,208	25,561	59%	43,208	27,448	15,760	57%
Net hedging income (loss)	(7,502)	(37,717)	30,215	80%	(37,717)	4,664	(42,381)	(909%)
Other	(52)	180	(232)	(129%)	180	—	180	—
Total	$272,888	$226,850	$46,038	20%	$226,850	$188,326	$ 38,524	20%
Average realized sales price per unit:								
Natural gas revenues from production (per Mcf)	$ 5.92	$ 5.46	$ 0.46	8%	$ 5.46	$ 3.46	$ 2.00	58%
Effects of hedging activities (per Mcf)	(0.19)	(0.93)	0.74	80%	(0.93)	0.10	(1.03)	(1,030%)
Average realized price (per Mcf)	$ 5.73	$ 4.53	$ 1.20	26%	$ 4.53	$ 3.56	$ 0.97	27%
Oil and condensate revenues from production (per Bbl)	$ 39.45	$ 30.56	$ 8.89	29%	$ 30.56	$ 26.39	$ 4.17	16%
Effects of hedging activities (per Bbl)	(0.39)	—	(0.39)	—	—	—	—	—
Average realized price (per Bbl)	$ 39.06	$ 30.56	$ 8.50	28%	$ 30.56	$ 26.39	$ 4.17	16%
Total revenues from production (per Mcfe)	$ 6.07	$ 5.39	$ 0.68	13%	$ 5.39	$ 3.57	$ 1.82	51%
Effects of hedging activities (per Mcfe)	(0.16)	(0.77)	0.61	79%	(0.77)	0.09	(0.86)	(956%)
Total average realized price (per Mcfe)	$ 5.91	$ 4.62	$ 1.29	28%	$ 4.62	$ 3.66	$ 0.96	26%
Expenses (per Mcfe):								
Lease operating expenses	$ 0.53	$ 0.46	$ 0.07	15%	$ 0.46	$ 0.35	$ 0.11	31%
Depreciation, depletion and amortization—oil and gas properties	$ 3.09	$ 2.56	$ 0.53	21%	$ 2.56	$ 2.12	$ 0.44	21%

Year Ended December 31, 2004 as Compared to the Year Ended December 31, 2003

Revenues and Production

Revenues increased $46.0 million, or 20%, in 2004 compared to 2003. The increase was primarily due to a decrease of $30.2 million, or 80%, in net hedging losses and a 13% higher average commodity price in 2004, partially offset by the impact of lower production of 2.8 Bcfe, or 6%, compared to 2003.

Production decreased approximately 2.8 Bcfe, or 6%, in 2004 compared to 2003 primarily due to normal production declines and weather-related delays. Average daily production in 2004 was 126 MMcfe compared to 134 MMcfe in 2003. Natural gas revenues decreased $9.5 million, or 4%, due primarily to 12% lower production, partially offset by the impact of an 8% higher average price in 2004. Excluding the effects of hedging activities, the 2004 average natural gas price was $5.92 per Mcf compared to $5.46 per Mcf in 2003. Oil and condensate revenues increased $25.6 million, or 59%, due primarily to a 29% higher average price and a 23% increase in production of 329 MBbls in 2004. Excluding the effects of hedging activities, the 2004 average oil and condensate price was $39.45 per barrel compared to $30.56 per barrel in 2003.

Lease Operating Expenses

Lease operating expenses include costs incurred to operate and maintain wells and related equipment and facilities. These costs include, among others, workover expenses, labor, materials, supplies, property taxes, insurance, severance taxes and transportation, gathering and processing expenses. Lease operating expenses increased $2.1 million, or 10%, in 2004 compared to 2003. Of the total increase in lease operating expenses, approximately $3.9 million related to fields that commenced production in 2004 and approximately $4.1 million related to fields that commenced production in 2003, partially offset by a decrease in workover expense of $3.0 million that primarily related to a 2003 pipeline workover at Green Canyon 177 (Sangria) and a net decrease of $2.9 million related to operating expenses on other fields.

Depreciation, Depletion and Amortization

DD&A increased $17.6 million, or 14%, in 2004 compared to 2003. Of the total increase in DD&A, $26.3 million related to a higher DD&A rate, offset in part by $8.7 million related to lower production volumes of 2.8 Bcfe. The 21% increase in the 2004 DD&A rate was primarily due to costs of $83.6 million associated with 13 unsuccessful wells in 2004, a net downward revision to proved reserves of 20.4 Bcfe and higher finding costs associated with certain discoveries in 2004 due primarily to the timing of reserve recognition.

General and Administrative

General and administrative expenses are overhead-related expenses, including among others, wages and benefits for non-capitalized employees, auditing fees, legal fees, insurance, office rent, travel and entertainment, computer supplies and maintenance and investor relations expenses. General and administrative expenses increased $3.0 million, or 23%, in 2004 compared to 2003. The increase was primarily due to higher employment-related costs of $1.5 million, higher legal and accounting fees of $0.6 million primarily related to compliance with Section 404 of the Sarbanes-Oxley Act of 2002 and business interruption insurance expense of $1.0 million for the period prior to first production at Front Runner, partially offset by a net decrease in other expenses of $0.1 million.

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

Revenues and Production

Revenues increased $38.5 million, or 20%, in 2003 compared to 2002. The increase was primarily due to a 51% higher average commodity price in 2003, partially offset by the impact of an increase in net hedging losses and other of $42.2 million and 5% lower production in 2003.

Production decreased approximately 2.4 Bcfe, or 5%, in 2003 compared to 2002 primarily due to normal production declines. Average daily production in 2003 was 134 MMcfe compared to 141 MMcfe in 2002. Natural gas revenues increased $65.0 million, or 42%, due primarily to a 58% higher average price in 2003, partially offset by the impact of a 10% decrease in production of approximately 4.7 Bcf. Excluding the effects of hedging activities, the 2003 average natural gas price was $5.46 per Mcf compared to $3.46 per Mcf in 2002. Oil and condensate revenues increased $15.8 million, or 57%, due primarily to a 16% higher average price in 2003 and a 36% increase in production of approximately 374 MBbls. The 2003 average oil and condensate price was $30.56 per barrel compared to $26.39 per barrel in 2002.

Lease Operating Expenses

Lease operating expenses increased $4.3 million, or 23%, in 2003 compared to 2002. Of the total increase in lease operating expenses, approximately $1.4 million related to increased workover activities, $2.0 million related to activity on blocks that commenced production in 2003 and $0.9 million related to increased operating expenses on existing properties. The 31% increase in the lease operating expense rate per Mcfe in 2003 was primarily due to a pipeline workover on Green Canyon 177 (Sangria) of $2.4 million, or $0.05 per Mcfe, and lower production volumes in 2003.

Depreciation, Depletion and Amortization

DD&A increased $16.3 million, or 15%, in 2003 compared to 2002. Of the total increase in DD&A, $22.5 million related to a higher DD&A rate, offset in part by $6.2 million related to lower production volumes of 2.4 Bcfe. The 21% increase in the DD&A rate was primarily due to costs of $34.3 million associated with nine unsuccessful wells in 2003 and higher finding costs associated with certain discoveries in 2003 due primarily to the timing of reserve recognition.

General and Administrative

General and administrative expenses increased $1.8 million, or 16%, in 2003 compared to 2002. The increase was primarily due to higher employment-related costs associated with an increase in the number of employees in 2002 and 2003.

Liquidity and Capital Resources

Our revenues, profitability, cash flow and future growth depend substantially on prevailing oil and gas prices and our ability to find and develop oil and gas reserves that are economically recoverable. A substantial or extended decline in oil and gas prices could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and gas reserves that may be economically produced and access to capital.

We have experienced and expect to continue to experience substantial capital requirements, primarily due to our active exploration and development programs in the Gulf of Mexico. Net additions to property and equipment in 2004 were $265.7 million, including asset retirement costs of $6.5 million. We have capital expenditure plans for 2005 totaling approximately $280.0 million. Based on this level of capital expenditures and current oil and gas prices, we expect our cash flow from operations to exceed our capital expenditures for the first time since our inception. However, we use a systematic risking process to select prospects for drilling. If we experience greater than anticipated success on budgeted projects, capital expenditures will increase.

Oil and gas prices have a significant impact on our cash flows available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under the Revolver is subject to semi-annual re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of oil and gas that we can economically produce. Lower prices and/or lower production may decrease revenues, cash flows and the borrowing base under the Revolver, thus reducing the amount of financial resources available to meet our capital requirements. We believe that cash flows from operations, proceeds from available borrowings under the Revolver and Front Runner spar production facility financing opportunities will be sufficient to meet our capital requirements in the next twelve months. However, additional debt or equity financing may be required in the future to fund growth and acquisition, exploration and development activities. In the event additional capital resources are unavailable, we may curtail drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

As of December 31, 2004, we had outstanding borrowings of $105.0 million. As of December 31, 2004, we were not in technical compliance with certain provisions of the Revolver related to the new subsidiaries we formed for our first international venture offshore Nigeria. However, as a result of the amendment to the Revolver on February 8, 2005, we are now in compliance with the provisions of the Revolver. Subsequent to December 31, 2004, we have had no additional borrowings under the Revolver, but we expect to incur additional borrowings in 2005. See "—*Financing Activities*" for more information.

Spinnaker has an effective shelf registration statement relating to the potential public offer and sale by us or certain of our 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 we will or could sell any such securities.

Contractual Obligations

We lease administrative offices, office equipment and oil and gas equipment under non-cancelable operating leases. Contractual obligations as of December 31, 2004 were as follows (in thousands):

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt obligations	$105,000	$ —	$105,000	$ —	$ —
Operating lease obligations	3,154	1,306	1,839	9	—
Other contractual obligations	25,763	—	5,153	10,305	10,305
Total	$133,917	$1,306	$111,992	$10,314	$10,305

Other contractual obligations of $25.8 million relate to facility and pipeline demand charges associated with our production capacity commitment for the Eastern Gulf Project. We will incur obligations in the ordinary course of business under purchase and service agreements that are not included in the table above. These obligations, among others, include estimated future development costs of approximately $209.3 million for the costs of drilling additional wells, completions, recompletions, platforms, pipelines, facilities, tie-backs and abandonments related to our proved reserves. Our asset retirement obligations as of December 31, 2004 were $40.5 million.

Components of Cash Flow

Cash and cash equivalents increased $6.5 million to $21.8 million as of December 31, 2004. The components of the increase in cash and cash equivalents included $219.7 million provided by operating activities, $277.3 million used in investing activities and $64.1 million provided by financing activities.

Operating Activities

Net cash provided by operating activities in 2004 increased 11% to $219.7 million primarily due to higher commodity prices. Cash flow from operations is dependent upon our ability to increase production through exploration and development activities and oil and gas prices. We have made significant investments to expand our operations in the Gulf of Mexico.

We sell our oil and gas production under fixed and floating market price contracts each month. We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and gas prices and to achieve more predictable cash flow. However, these contracts limit the benefits we would realize if prices increase. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

As of December 31, 2004, Spinnaker had negative working capital of $13.5 million. Our cash flow from operations depends on our ability to manage working capital, including accounts receivable, accounts payable and accrued liabilities. The net increase of $18.7 million in accounts receivable was primarily related to increases of $12.9 million in oil and gas revenues receivable and $6.3 million in joint interest billings. Oil and gas revenues receivable increased primarily due to higher commodity prices in December 2004. Joint interest billings fluctuate from period to period based on the number of wells we operate and the timing of billings to and collections from other working interest owners. Accounts payable and accrued liabilities increased $2.4 million. Fluctuations from period to period occur based on exploratory and development activities in progress and the timing of our payments to vendors and other operators.

The net increase of $11.7 million in other assets was primarily related to an obligation for reimbursement of prior expenses incurred by Devon related to the international venture. The amount will be transferred to oil and gas properties when we receive approval of the transfer of interest from the Nigerian government. If we do not receive the Nigerian government approvals, the $11.8 million will be reimbursed to us by Devon.

Investing Activities

Net cash used in investing activities was $277.3 million in 2004 and included oil and gas property expenditures of $276.9 million and purchases of other property and equipment of $0.4 million.

As part of our strategy, we explore for oil and gas at deeper drilling depths and in the deep water of the Gulf of Mexico, where operations are more difficult and costly than at shallower drilling depths and in shallower water. Along with higher risks and costs associated with these areas, greater opportunity exists for reserve additions. We have experienced and will continue to experience significantly higher drilling costs for deep shelf and deepwater projects relative to the drilling costs on shallower depth shelf projects in the Gulf of Mexico. Historically, most of the wells we drilled were on the shelf. However, we are in the process of transitioning to more deepwater operations. Prior to 2001, we drilled nine deepwater wells, three of which were successful. Since 2001, we have drilled 32 deepwater wells, 21 of which were successful. In 2005, we expect to drill approximately nine additional deepwater wells in the Gulf of Mexico and two deepwater wells in West Africa.

In order to diversify our operations, we entered into a farm-out agreement in December 2004 covering a 12.5% interest in OPL Block 256 offshore Nigeria from Devon. The transfer of interest is pending various approvals within the Nigerian government. We expect our capital requirements for exploratory activities in connection with this venture to be approximately $50 million to $60 million over a two to three year period beginning in the first quarter of 2005. In connection with the farm-out agreement, we paid Devon approximately $11.8 million as reimbursement of prior expenses it incurred related to the block. If we do not receive the Nigerian government approvals, the $11.8 million will be reimbursed to us by Devon.

We drilled 27 wells in 2004, 14 of which were successful. In 2003, we drilled 29 wells, 20 of which were successful. Since inception and through December 31, 2004, we drilled 176 wells, 104 of which were successful, representing a success rate of 59%. Dry hole costs, including associated leasehold costs, were $83.6 million in 2004. Our current capital expenditure budget for 2005 is approximately $280.0 million, including $190.0 million for exploration activities and geological and geophysical expenditures, $45.0 million for development activities, $41.0 million for leasehold acquisitions and $4.0 million for other property and equipment. We currently plan to drill approximately 21 wells in 2005, including ten wells on the Gulf of Mexico shelf, nine wells in the deep water of the Gulf of Mexico and two wells in West Africa. Actual levels of capital expenditures may vary due to many factors, including drilling results, oil and gas 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.

We settled asset retirement obligations of $2.1 million in 2004. Current liabilities include asset retirement obligations of $6.8 million, the settlements of which will depend on the timing of abandonment decisions and equipment availability in 2005.

The costs associated with unproved properties and properties under development not included in the amortization base were as follows (in thousands):

	As of December 31, 2004	As of December 31, 2003
Leasehold, delay rentals and seismic data, hardware and software costs	$128,465	$123,767
Wells in-progress	3,836	29,459
Wells pending determination	14,820	—
Other	1,156	2,047
Total	$148,277	$155,273

Financing Activities

Net cash provided by financing activities of $64.1 million in 2004 related to proceeds of $55.0 million from borrowings and $9.2 million from stock option exercises. We paid debt issue costs of approximately $0.1 million in connection with the Revolver.

On December 19, 2003, our wholly-owned subsidiary, Spinnaker Exploration Company, L.L.C., entered into the Revolver, a $200.0 million revolving credit agreement with a group of eight banks. The Revolver consists of two tranches, Tranche A and Tranche B. Borrowings under each tranche constitute senior indebtedness. The obligations under the Revolver are fully and unconditionally guaranteed by Spinnaker.

Tranche A is available on a revolving basis through December 19, 2006, the maturity date of the Revolver, and availability is subject to the borrowing base determined by the banks. The borrowing base was $140.0 million as of December 31, 2004. Tranche B is $50.0 million, is available in multiple advances through April 1, 2005 and is not subject to the borrowing base. Borrowings under Tranche B cannot be reborrowed once repaid. Total availability under Tranche A and Tranche B cannot exceed $200.0 million. Should the borrowing base exceed $150.0 million, Tranche B would be reduced by a like amount for the period the borrowing base exceeds $150.0 million until the maturity of Tranche B. The obligations under Tranche A are unsecured. At such time Tranche B is utilized, the banks are to be provided with security interests in virtually all of our reserve base. Upon repayment of Tranche B, the security interests are to be released.

The borrowing base is re-determined semi-annually by the banks in their sole discretion and in their usual and customary manner. Spinnaker and the banks also have the right to request one additional re-determination annually. The amount of the borrowing base is a function of the banks' view of our reserve profile, future commodity prices and projected cash flows. In addition to the semi-annual re-determinations, the banks have the right to re-determine the borrowing base in the event of the sale, transfer or disposition of assets included in the borrowing base exceeding $25.0 million, or $10.0 million when Tranche B is utilized.

We have the option to elect to use a base interest rate as described below or the London Interbank Offered Rate ("LIBOR") plus, for each such rate, a spread based on the percentage of the borrowing base used at that time. The base rate spread ranges from 0.0% to 0.5% for Tranche A borrowings and from 2.0% to 2.75% for Tranche B borrowings. The LIBOR spread ranges from 1.25% to 2.0% for Tranche A borrowings and from 3.0% to 3.75% for Tranche B borrowings. The base interest rate under the Revolver is a fluctuating rate of interest equal to the base rate spread plus the higher of either (i) The Toronto-Dominion Bank's base rate for dollar advances made in the United States or (ii) the Federal Funds Rate plus 0.5% per annum. The weighted average interest rate was 3.28% in 2004. The commitment fee rate ranges from 0.375% to 0.5%, depending on the borrowing base usage for Tranche A, and is 0.625% for Tranche B.

The Revolver also includes the following restrictions and covenants:

- Incurrence of other debt is prohibited except that senior debt may not exceed $10.0 million ($5.0 million when Tranche B is used), vendor indebtedness for the purchase of seismic data may not exceed $25.0 million, subordinated debt is permitted subject to certain conditions and a lease transaction involving the Front Runner spar production facility is specifically permitted.
- Liens are generally prohibited; however, we may grant a lien in connection with the purchase of seismic data, pledges and deposits to secure hedging arrangements not to exceed $15.0 million and lease financing arrangements involving our interest in the Front Runner spar production facility.
- Stock buy-backs exceeding $10.0 million are prohibited in any fiscal year.
- The ratio of debt to EBITDA may not exceed 2.50 to 1.00.
- The ratio of current assets to current liabilities may not be less than 1.00 to 1.00. For purposes of the calculation, availability under the Revolver is added to current assets and maturities of the Revolver are

excluded from current liabilities. Hedging assets and liabilities and asset retirement obligations are also excluded from this calculation.

- Our tangible net worth is required to exceed 80% of the level at September 30, 2003, plus 50% of future net income with certain non-cash gains and losses excluded from net income, plus 75% of future equity issuances.
- Our hedging transactions must not exceed 66⅔% of estimated future production for the next 18 months and 33⅓% for the period 19 to 36 months from the date of the transaction. There are also credit rating restrictions on counterparties as well as concentration limits.

On February 8, 2005, Spinnaker and the banks amended the Revolver. The amendment was intended to give us:

- the flexibility to engage in business activities through entities other than our subsidiary, Spinnaker Exploration Company, L.L.C., including activities in international locations;
- the ability to make investments and provide guarantees and extensions of credit to entities other than our subsidiary;
- a basket of up to $75.0 million a year to make distributions from our subsidiary to us, to request letters of credit under the Revolver for activities other than those of our subsidiary, subject to the limits under the Revolver, and to provide extensions of credit from our subsidiary to other entities; and
- an increase in the aggregate amount of the borrowing base available under the Revolver for letters of credit up to $60.0 million, subject to certain limitations.

As of December 31, 2004, we had outstanding borrowings of $105.0 million. Current availability is $35.0 million and $50.0 million under Tranche A and Tranche B, respectively. As of December 31, 2004, we were not in technical compliance with certain provisions of the Revolver related to the new subsidiaries we formed for our first international venture offshore Nigeria. However, as a result of the amendment to the Revolver on February 8, 2005, we are now in compliance with the provisions of the Revolver. Subsequent to December 31, 2004, we have had no additional borrowings under the Revolver, but we expect to incur additional borrowings in 2005.

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

Commodity Price Risk

Our revenues, profitability and future growth depend substantially on prevailing oil and gas prices. Oil and gas prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. Lower prices may also reduce the amount of oil and gas that we can economically produce. We sell our oil and gas production under fixed and floating market price contracts each month. We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and gas prices and to achieve more predictable cash flow. We do not enter into such hedging arrangements for trading purposes. However, these contracts limit the benefits we would realize if prices increase. Our current financial derivative contracts include fixed price swap contracts and cashless collar arrangements that have been placed with major trading counterparties we believe represent minimum credit risks. We cannot provide assurance that these trading counterparties will not become credit risks in the future. Under our current hedging practice, we generally do not hedge more than 66⅔% of our estimated twelve-month production quantities without the prior approval of the Risk Management Committee of our Board of Directors.

We enter into NYMEX related swap contracts and collar arrangements from time to time. The natural gas swap contracts and collar arrangements will settle based on the reported settlement price on the NYMEX for the last trading day of each month. The crude oil swap contracts and collar arrangements will settle based on the average of the settlement price for each commodity business day in the contract month.

In a swap transaction, the counterparty is required to make a payment to us for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. We are 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. In a collar arrangement, the counterparty is required to make a payment to us for the difference between the fixed floor price and the settlement price if the settlement price is below the fixed floor price. We are 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 and ceiling prices. As of December 31, 2004, our commodity price risk management positions in swap contracts and collar arrangements were as follows:

Natural Gas

	Fixed Price Swaps		Collars		
Period	Average Daily Volume (MMBtus)	Weighted Average Price (Per MMBtu)	Average Daily Volume (MMBtus)	Weighted Average Price (Per MMBtu) Floor	Weighted Average Price (Per MMBtu) Ceiling
First Quarter 2005	20,000	$7.76	—	$—	$—

Oil

	Fixed Price Swaps		Collars		
Period	Average Daily Volume (Bbls)	Weighted Average Price (Per Bbl)	Average Daily Volume (Bbls)	Weighted Average Price (Per Bbl) Floor	Weighted Average Price (Per Bbl) Ceiling
Calendar 2005	1,000	$40.34	3,000	$38.67	$44.73

We reported a net hedging asset of $1.2 million and a net hedging liability of $2.7 million related to financial derivative contracts as of December 31, 2004 and 2003, respectively. Amounts related to hedging activities were as follows (in thousands):

	As of December 31, 2004	As of December 31, 2003
Current assets:		
Hedging assets	$2,829	$ 203
Deferred tax asset related to hedging activities	—	972
Current liabilities:		
Hedging liabilities	$1,628	$ 2,903
Deferred tax liability related to hedging activities	432	—
Equity:		
Accumulated other comprehensive income (loss)	$ 963	$(1,728)

The ineffective component of the derivatives and net hedging gains (losses) were recorded in revenues in 2004, 2003 and 2002 as follows (in thousands):

	Year Ended December 31, 2004	2003	2002
Ineffective component of derivatives	$ (194)	$ —	$ —
Net hedging income (loss)	$(7,502)	$(37,717)	$4,664

Based on future oil and gas prices as of December 31, 2004, we would reclassify a net gain of approximately $1.0 million from accumulated other comprehensive income (loss) to earnings in 2005. The amounts ultimately reclassified into earnings will vary due to changes in the fair value of the open derivative contracts prior to settlement.

To calculate the potential effect of the derivative contracts on future revenues, we applied NYMEX oil and gas forward prices as of December 31, 2004 to the quantity of our oil and 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 Increase (Decrease) in Revenues at Current Prices	Estimated Increase in Revenues with 10% Decrease in Prices	Estimated Increase (Decrease) in Revenues with 10% Increase in Prices
Natural gas swaps	$2,829	$3,949	$ 1,721
Oil swaps	(822)	730	(2,379)
Oil collars	(806)	1,067	(6,312)

Subsequent to December 31, 2004, the fair value of our open commodity price risk management positions in swap contracts and collar arrangements using average oil and gas forward prices of $53.73 and $7.12, respectively, as of March 10, 2005 was a net liability of approximately $13.7 million. First quarter 2005 settlements resulted in income of $1.9 million. Following are our commodity price risk management positions in swap contracts and collar arrangements as of March 10, 2005:

Natural Gas

	Fixed Price Swaps		Collars		
Period	Average Daily Volume (MMBtus)	Weighted Average Price (Per MMBtu)	Average Daily Volume (MMBtus)	Weighted Average Price (Per MMBtu) Floor	Weighted Average Price (Per MMBtu) Ceiling
First Quarter 2005	20,000	$7.76	—	$—	$—
Second Quarter 2005	10,000	6.40	—	—	—
Third Quarter 2005	10,000	6.40	—	—	—
Fourth Quarter 2005	3,370	6.40	—	—	—

Oil

	Fixed Price Swaps		Collars		
Period	Average Daily Volume (Bbls)	Weighted Average Price (Per Bbl)	Average Daily Volume (Bbls)	Weighted Average Price (Per Bbl) Floor	Weighted Average Price (Per Bbl) Ceiling
Calendar 2005	1,000	$40.34	3,000	$38.67	$44.73

Interest Rate Risk

We are 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 Revolver. We do not currently use interest rate derivative financial instruments to manage exposure to interest rate changes, but may do so in the future.

Item 8. *Financial Statements and Supplementary Data*

The consolidated financial statements and supplementary data of the Company appear on pages 47 through 76 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 our accountants or any reportable events regarding accounting principles or practices or financial statement disclosures.

Item 9A. *Controls and Procedures*

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of our disclosure controls and procedures, as this term is defined under Rule 13a-15(e) promulgated under the Exchange Act. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2004.

Design and Evaluation of Internal Control Over Financial Reporting

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, we have included a report of management's assessment of the design and effectiveness of our internal controls for the fiscal year ended December 31, 2004 as part of this Annual Report on Form 10-K. KPMG LLP, our independent public accountants, also attested to, and reported on, management's assessment of the effectiveness of internal control over financial reporting. Management's report and the independent registered public accounting firm's attestation report are included in our Consolidated Financial Statements under "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm" and are incorporated herein by reference.

Changes in Internal Control Over Financial Reporting

During the three months ended December 31, 2004, we made no change in our internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. *Other Information*

In connection with our wholly-owned subsidiary, Spinnaker Exploration Company, L.L.C., entering into the $200.0 million Revolver, Spinnaker Exploration Company executed a full and unconditional guaranty of the obligations of Spinnaker Exploration Company, L.L.C. under the Revolver. The guaranty contained certain negative covenants, one of which prohibited Spinnaker Exploration Company from entering into or conducting any business other than holding the membership interests of Spinnaker Exploration Company, L.L.C. and the capital stock of WP Spinnaker Holdings, Inc. In connection with our entering into a farm-out agreement covering a 12.5% interest in OPL Block 256 offshore Nigeria from Devon, Spinnaker Exploration Company formed various subsidiaries in breach of its guaranty under the Revolver, the first of which was organized on December 9, 2004. The formation of these subsidiaries triggered an event of default under the Revolver that resulted in the acceleration of our outstanding long-term debt under the Revolver in the amount of $105.0 million, although the lenders under the Revolver did not seek repayment of our outstanding balance under the Revolver. As a result of the amendment to the Revolver on February 8, 2005, we are no longer in default under the Revolver. For a description of the amendment to the Revolver, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Financing Activities" in this Annual Report.

On February 10, 2005, the Compensation Committee of our Board of Directors approved discretionary bonuses for 2004 and established base salaries for 2005 for all of our officers and employees. The following table sets forth the 2004 discretionary bonus and the 2005 annual base salary for each of our named executive officers as approved by the Compensation Committee of our Board of Directors:

Name	2004 Bonus	2005 Base salary
Roger L. Jarvis	$161,000	$476,100
Scott A. Griffiths	117,000	346,465
Robert M. Snell	128,000	270,883
L. Scott Broussard	90,000	229,392
Jeffrey C. Zaruba	107,000	172,427

PART III

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

Spinnaker's Definitive Proxy Statement for our 2005 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.

Our Board of Directors has adopted a code of ethics for our Chief Executive Officer, Chief Financial Officer, Principal Accounting Officer and other senior financial officers. The Financial Code of Ethics is available on our internet website at www.spinnakerexploration.com and available in print, free of charge, upon stockholder request to Spinnaker Exploration Company, 1200 Smith Street, Suite 800, Houston, Texas 77002, Attention: Corporate Secretary.

Item 11. *Executive Compensation*

Spinnaker's Definitive Proxy Statement for our 2005 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*

Spinnaker's Definitive Proxy Statement for our 2005 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.

Item 13. *Certain Relationships and Related Transactions*

Spinnaker's Definitive Proxy Statement for our 2005 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. *Principal Accountant Fees and Services*

Spinnaker's Definitive Proxy Statement for our 2005 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 14.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules***

(a) Documents Filed as a Part of this Report:

(1) Financial Statements

See "Index to Consolidated Financial Statements" on page 47.

(2) Financial Statement Schedules

None.

(3) Exhibits

See "Exhibit Index" on page 77.

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 Stock Option Plan (incorporated by reference to Exhibit 10.2 to Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
10.5	—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 Statement on Form S-1 (Commission File No. 333-83093))
10.6	—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 Statement on Form S-1 (Commission File No. 333-83093))
10.7	—1999 Stock Incentive Plan (incorporated by reference to Exhibit 10.10 to Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
10.8	—1999 Employee Stock Purchase Plan (incorporated by reference to Exhibit 10.11 to Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
10.9	—Form of Indemnification Agreement (incorporated by reference to Exhibit 10.12 to Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
10.10	—Adjunct Stock Option Plan (incorporated by reference to Exhibit 4.3 to Spinnaker's Registration Statement on Form S-8 (Commission File No. 333-36592))
10.11	—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, 2000)
10.12	—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 File No. 333-61888))
10.13	—Spinnaker Exploration Company 2003 Stock Option Plan (incorporated by reference to Exhibit 10.1 to Spinnaker's Registration Statement on Form S-8 (Commission File No. 333-105461))

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 14, 2005

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 14, 2005
/s/ ROBERT M. SNELL Robert M. Snell	Vice President, Chief Financial Officer and Secretary (Principal Financial Officer)	March 14, 2005
/s/ JEFFREY C. ZARUBA Jeffrey C. Zaruba	Vice President, Treasurer and Assistant Secretary (Principal Accounting Officer)	March 14, 2005
/s/ WALTER R. ARNHEIM Walter R. Arnheim	Director	March 14, 2005
/s/ SHELDON R. ERIKSON Sheldon R. Erikson	Director	March 14, 2005
/s/ JEFFREY A. HARRIS Jeffrey A. Harris	Director	March 14, 2005
/s/ MICHAEL E. MCMAHON Michael E. McMahon	Director	March 14, 2005
/s/ HOWARD H. NEWMAN Howard H. Newman	Director	March 14, 2005
/s/ MICHAEL E. WILEY Michael E. Wiley	Director	March 14, 2005

GLOSSARY OF OIL AND GAS TERMS

The following is a description of the meanings of some of the oil and gas 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 oil or natural gas, 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 oil or natural gas 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 oil or gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or gas 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 an oil or gas 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 oil and/or gas 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 oil or gas 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.

SPINNAKER EXPLORATION COMPANY

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

SPINNAKER EXPLORATION COMPANY

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Board of Directors and Stockholders of
Spinnaker Exploration Company

Spinnaker Exploration Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Under the supervision and with the participation of management, including Spinnaker Exploration Company's principal executive officer and principal financial officer, Spinnaker Exploration Company conducted an evaluation of the effectiveness of internal control over financial reporting based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on Spinnaker Exploration Company's evaluation under the framework in *Internal Control—Integrated Framework*, our principal executive officer and principal financial officer concluded that internal control over financial reporting was effective as of December 31, 2004.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Spinnaker Exploration Company's independent auditors have issued an attestation report on management's assessment of the internal control over financial reporting as of December 31, 2004. Their report is included herein.

/s/ ROGER L. JARVIS

Roger L. Jarvis
Chief Executive Officer

/s/ ROBERT M. SNELL

Robert M. Snell
Chief Financial Officer

Report Of Independent Registered Public Accounting Firm

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

We have audited management's assessment, included in the accompanying "Management's Report on Internal Control Over Financial Reporting," that Spinnaker Exploration Company maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Spinnaker Exploration Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Spinnaker Exploration Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, Spinnaker Exploration Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Spinnaker Exploration Company and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of operations, equity and cash flows for each of the years in the three-year period ended December 31, 2004, and our report dated March 11, 2005 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Houston, Texas
March 11, 2005

Report Of Independent Registered Public Accounting Firm

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, 2004 and 2003, and the related consolidated statements of operations, equity and cash flows for each of the years in the three-year period ended December 31, 2004. 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Spinnaker Exploration Company and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2004, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Spinnaker Exploration Company's internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 11, 2005 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

As explained in Note 2 to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations.

KPMG LLP

Houston, Texas
March 11, 2005

SPINNAKER EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share data)

	As of December 31,	
	2004	2003
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 21,830	$ 15,315
Accounts receivable, net of allowance for doubtful accounts of $3,232 as of December 31, 2004 and 2003, respectively	48,785	30,067
Hedging assets	2,829	203
Other	3,467	4,193
Total current assets	76,911	49,778
PROPERTY AND EQUIPMENT:		
Oil and gas, on the basis of full-cost accounting:		
Proved properties	1,447,824	1,175,443
Unproved properties and properties under development, not being amortized	148,277	155,273
Other	6,651	6,301
	1,602,752	1,337,017
Less—Accumulated depreciation, depletion and amortization	(541,615)	(397,349)
Total property and equipment	1,061,137	939,668
OTHER ASSETS	12,883	1,136
Total assets	$1,150,931	$ 990,582
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 34,692	$ 18,723
Accrued liabilities and other	47,264	60,874
Hedging liabilities	1,628	2,903
Asset retirement obligations, current portion	6,841	446
Total current liabilities	90,425	82,946
LONG-TERM DEBT	105,000	50,000
ASSET RETIREMENT OBLIGATIONS	33,644	32,548
DEFERRED INCOME TAXES	107,776	81,027
COMMITMENTS AND CONTINGENCIES (Note 11)		
EQUITY:		
Preferred stock, $0.01 par value; 10,000,000 shares authorized; no shares issued and outstanding as of December 31, 2004 and 2003, respectively	—	—
Common stock, $0.01 par value; 50,000,000 shares authorized; 33,927,158 shares issued and 33,920,018 shares outstanding as of December 31, 2004 and 33,385,248 shares issued and 33,374,844 shares outstanding as of December 31, 2003	339	334
Additional paid-in capital	612,920	599,532
Retained earnings	199,882	145,949
Less: Treasury stock, at cost, 7,140 and 10,404 shares as of December 31, 2004 and 2003, respectively	(18)	(26)
Accumulated other comprehensive income (loss)	963	(1,728)
Total equity	814,086	744,061
Total liabilities and equity	$1,150,931	$ 990,582

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

SPINNAKER EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except share data)

	Year Ended December 31,		
	2004	2003	2002
REVENUES	$272,888	$226,850	$188,326
EXPENSES:			
Lease operating expenses	24,633	22,489	18,212
Depreciation, depletion and amortization—oil and gas properties	142,913	125,331	108,998
Depreciation and amortization—other	1,353	1,310	914
Accretion expense	3,054	2,251	—
Gain on settlement of asset retirement obligations	(133)	(464)	—
General and administrative	15,787	12,773	10,984
Charges related to Enron bankruptcy	—	—	128
Total expenses	187,607	163,690	139,236
INCOME FROM OPERATIONS	85,281	63,160	49,090
OTHER INCOME (EXPENSE):			
Interest income	195	201	1,014
Interest expense, net	(1,206)	(784)	(762)
Other	—	140	—
Total other income (expense)	(1,011)	(443)	252
INCOME BEFORE INCOME TAXES	84,270	62,717	49,342
Income tax expense	30,337	22,578	17,763
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	53,933	40,139	31,579
Cumulative effect of change in accounting principle (Note 2)	—	(3,527)	—
NET INCOME	$ 53,933	$ 36,612	$ 31,579
BASIC INCOME PER COMMON SHARE:			
Income before cumulative effect of change in accounting principle	$ 1.60	$ 1.21	$ 1.00
Cumulative effect of change in accounting principle	—	(0.11)	—
NET INCOME PER COMMON SHARE	$ 1.60	$ 1.10	$ 1.00
DILUTED INCOME PER COMMON SHARE:			
Income before cumulative effect of change in accounting principle	$ 1.55	$ 1.18	$ 0.97
Cumulative effect of change in accounting principle	—	(0.10)	—
NET INCOME PER COMMON SHARE	$ 1.55	$ 1.08	$ 0.97
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:			
Basic	33,771	33,234	31,695
Diluted	34,807	33,880	32,653

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	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Total Equity	Comprehensive Income
	Preferred	Common	Preferred	Common						
Balance, December 31, 2001	—	27,308,912	$—	$273	$365,993	$ 77,758	$(39)	$ 14,507	$458,492	
Net income	—	—	—	—	—	31,579	—	—	31,579	$ 31,579
Other comprehensive income, net of tax:										
Net change in fair value of derivative financial instruments	—	—	—	—	—	—	—	(24,269)	(24,269)	(24,269)
Financial derivative settlements reclassed to income	—	—	—	—	—	—	—	(2,985)	(2,985)	(2,985)
Comprehensive income										$ 4,325
Common stock issuance, net of issuance costs	—	5,750,000	—	58	227,326	—	—	—	227,384	
Exercise of stock options	—	116,489	—	1	948	—	7	—	956	
Employer contributions to 401(k) Plan	—	9,062	—	—	287	—	—	—	287	
Stock compensation costs	—	—	—	—	177	—	—	—	177	
Tax benefit associated with exercise of non-qualified stock options	—	—	—	—	1,356	—	—	—	1,356	
Balance, December 31, 2002	—	33,184,463	$—	$332	$596,087	$109,337	$(32)	$(12,747)	$692,977	
Net income	—	—	—	—	—	36,612	—	—	36,612	$ 36,612
Other comprehensive income, net of tax:										
Net change in fair value of derivative financial instruments	—	—	—	—	—	—	—	(13,120)	(13,120)	(13,120)
Financial derivative settlements reclassed to income	—	—	—	—	—	—	—	24,139	24,139	24,139
Comprehensive income										$ 47,631
Exercise of stock options	—	184,661	—	2	2,129	—	6	—	2,137	
Employer contributions to 401(k) Plan	—	16,124	—	—	363	—	—	—	363	
Tax benefit associated with exercise of non-qualified stock options	—	—	—	—	953	—	—	—	953	
Balance, December 31, 2003	—	33,385,248	$—	$334	$599,532	$145,949	$(26)	$ (1,728)	$744,061	
Net income	—	—	—	—	—	53,933	—	—	53,933	$ 53,933
Other comprehensive income, net of tax:										
Net change in fair value of derivative financial instruments	—	—	—	—	—	—	—	(2,111)	(2,111)	(2,111)
Financial derivative settlements reclassed to income	—	—	—	—	—	—	—	4,802	4,802	4,802
Comprehensive income										$ 56,624
Exercise of stock options	—	529,262	—	5	9,162	—	8	—	9,175	
Employer contributions to 401(k) Plan	—	12,648	—	—	442	—	—	—	442	
Stock compensation costs	—	—	—	—	196	—	—	—	196	
Tax benefit associated with exercise of non-qualified stock options	—	—	—	—	3,588	—	—	—	3,588	
Balance, December 31, 2004	—	33,927,158	$—	$339	$612,920	$199,882	$(18)	$ 963	$814,086	

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,		
	2004	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 53,933	$ 36,612	$ 31,579
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	144,266	126,641	109,912
Accretion expense	3,054	2,251	—
Gain on settlement of asset retirement obligations	(133)	(464)	—
Deferred income tax expense	30,337	22,138	18,063
Cumulative effect of change in accounting principle	—	3,527	—
Other	832	364	881
Change in operating assets and liabilities:			
Accounts receivable	(18,718)	7,505	(13,443)
Accounts payable and accrued liabilities	6,291	(2,099)	7,726
Other assets	(130)	1,635	(759)
Net cash provided by operating activities	219,732	198,110	153,959
CASH FLOWS FROM INVESTING ACTIVITIES:			
Oil and gas properties	(276,941)	(266,054)	(361,163)
Proceeds from sale of oil and gas property and equipment	—	1,148	—
Purchases of other property and equipment	(350)	(1,152)	(2,654)
Net cash used in investing activities	(277,291)	(266,058)	(363,817)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	55,000	50,000	37,000
Payments on borrowings	—	—	(37,000)
Proceeds from exercise of stock options	9,175	2,136	956
Debt issue costs	(101)	(1,416)	—
Proceeds from issuance of common stock	—	—	227,873
Common stock issuance costs	—	—	(489)
Net cash provided by financing activities	64,074	50,720	228,340
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	6,515	(17,228)	18,482
CASH AND CASH EQUIVALENTS, beginning of year	15,315	32,543	14,061
CASH AND CASH EQUIVALENTS, end of year	$ 21,830	$ 15,315	$ 32,543
SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Cash paid for interest	$ 3,459	$ 570	$ 468
Cash paid (received) for income taxes, net	$ —	$ 440	$ (300)

The accompanying notes are an integral part of these 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 oil and gas in the U.S. Gulf of Mexico and West Africa. In December 2004, the Company entered into its first international venture offshore Nigeria. The transfer of the 12.5% interest from the operator to the Company is pending various approvals within the Nigerian government.

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 oil and gas properties. Oil and gas 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.

Change in Presentation

Certain financial statement items have been reclassified in prior years to conform to the current year presentation.

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 and Other Assets

Other current assets include unamortized debt financing costs of $0.6 million and $0.6 million as of December 31, 2004 and 2003, respectively. Other non-current assets include unamortized debt financing costs of $0.6 million and $1.1 million as of December 31, 2004 and 2003, 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 $0.6 million, $0.4 million and $0.3 million for the years ended December 31, 2004, 2003 and 2002, respectively.

Other non-current assets also include an $11.8 million obligation for reimbursement of prior expenses incurred by the operator in connection with the international venture. The amount will be transferred to oil and gas properties when Spinnaker receives approval of the transfer of interest from the Nigerian government. If Spinnaker does not receive the approval, the amount will be reimbursed to the Company by the operator.

Full Cost Method of Accounting

The Company uses the full cost method of accounting for its investments in oil and gas properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs incurred for the purpose of exploring for and developing oil and gas, 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, and geological and geophysical service costs. Development costs include the costs of drilling development wells, completions, platforms, facilities, pipelines and the costs related to the retirement of these assets. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of oil and gas 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 oil and gas reserves. Substantially all the Company's exploration activities are conducted jointly with others and, accordingly, the oil and gas property balances reflect only its proportionate interest in such activities.

Depreciation, Depletion and Amortization

The Company computes the provision for DD&A of oil and gas properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unevaluated 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 and estimated salvage values of platforms and other equipment associated with future asset retirement obligations.

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, 2004, the Company excluded from the amortization base estimated future expenditures of $27.9 million associated with common development costs for its deepwater discovery at Green Canyon 338/339/382 ("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

Under full cost accounting rules, total capitalized costs are limited to a ceiling equal to the present value of future net cash flows from proved oil and gas reserves, discounted at 10% per annum, plus the lower of cost or fair value of unproved properties less income tax effects (the "ceiling limitation"). We perform a quarterly ceiling test to determine whether the net book value of our full cost amortization base exceeds the ceiling limitation. If capitalized costs, net of accumulated DD&A, less related deferred taxes are greater than the ceiling limitation, a write-down or impairment of the full cost amortization base is required. A write-down of the carrying value of oil and gas properties is a non-cash charge that reduces earnings and typically results in lower DD&A expense in future periods.

In accordance with Commission guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. In addition, subsequent to the adoption of Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations," the future cash outflows associated with the settlement of asset retirement obligations are not included in the computation of the discounted present value of future net cash flows for the purposes of the ceiling test calculation.

Unproved Properties

The costs associated with unproved properties and properties under development are not initially included in the amortization base and primarily relate to unevaluated leasehold costs, delay rentals, geological and geophysical costs, wells in-progress and wells pending determination.

Geological and geophysical costs, including 3-D seismic data costs and related seismic hardware and software costs, are included in the full cost amortization base as incurred when such costs cannot be associated with specific unevaluated properties for which the Company owns a direct interest. Seismic data costs are associated with specific unevaluated properties if the seismic data may be used to evaluate acreage that is covered by a leasehold interest owned by the Company. The Company makes this determination based on an analysis of leasehold and seismic maps and discussions with the Company's management and exploration managers. Seismic hardware and software costs are associated with specific unevaluated properties if the hardware and software was acquired specifically to process or reprocess certain 3-D seismic data that covers an area or trend containing a leasehold interest owned by the Company. The Company makes this determination based on discussions with the Company's management and information technology and seismic processing specialists. When such seismic data, hardware and software costs can be associated with specific unevaluated properties and excluded from the full cost amortization base, the Company allocates the costs based on management's judgment of the potential economic value to be realized upon determination of whether or not proved reserves can be assigned to the properties. Significant assumptions used by management in determining the potential economic value of an owned leasehold interest include the number of successful and unsuccessful wells drilled within and around the lease and trend, the number of prospects on the lease and the size of the potential resource associated with the lease.

Unevaluated leasehold costs, delay rentals and geological and geophysical costs associated with specific properties are transferred to the amortization base either upon determination of whether or not proved reserves can be assigned to the properties or if impairment has occurred. The costs of drilling exploratory dry holes are transferred to the amortization base immediately upon determination that the well is unsuccessful. The costs associated with wells in-progress and wells pending determination are transferred to the amortization base upon determination of whether or not proved reserves can be assigned to the properties.

The costs associated with unproved properties and properties under development not included in the amortization base were as follows (in thousands):

	As of December 31,	
	2004	2003
Leasehold, delay rentals and seismic data, hardware and software costs	$128,465	$123,767
Wells in-progress	3,836	29,459
Wells pending determination	14,820	—
Other	1,156	2,047
Total	$148,277	$155,273

Leasehold Costs

In September 2004, the Financial Accounting Standards Board ("FASB") issued FASB Staff Position ("FSP") No. FAS 142-2, "Application of FASB Statement No. 142, Goodwill and Other Intangible Assets to Oil and Gas Producing Entities." This FSP confirms that SFAS No. 142 did not change the balance sheet classification or disclosure requirements for drilling and mineral rights of oil and gas producing entities. We classify the costs of oil and gas drilling and mineral rights as property and equipment.

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 $7.6 million, $6.7 million and $5.9 million in 2004, 2003 and 2002, respectively.

Capitalized Interest

The Company capitalized interest related to its unevaluated oil and gas properties of $2.9 million, $0.4 million and $0 for the years ended December 31, 2004, 2003 and 2002, respectively.

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.

Asset Retirement Obligations

Effective January 1, 2003, Spinnaker adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 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. As of January 1, 2003, the Company recorded asset retirement costs of $21.4 million and asset retirement obligations of $26.0 million. The cumulative effect of change in accounting principle was $3.5 million, net of taxes of $2.0 million.

The reconciliation of the beginning and ending asset retirement obligations is as follows (in thousands):

	December 31, 2004	December 31, 2003
Asset retirement obligations, beginning of year	$32,994	$ —
Liabilities upon adoption of SFAS No. 143 on January 1, 2003	—	25,954
Liabilities incurred	7,366	9,365
Liabilities settled(1)	(2,073)	(3,858)
Accretion expense	3,054	2,251
Revisions in estimated cash flows	(856)	(718)
Asset retirement obligations, end of year	$40,485	$32,994

(1) The cost of asset retirements in 2004 was approximately $2.0 million resulting in a gain on settlement of asset retirement obligations of $0.1 million. The cost of asset retirements in 2003 was approximately $3.4 million, resulting in a gain on settlement of asset retirement obligations of approximately $0.5 million.

The following table summarizes the pro forma net income and earnings per share for the year ended December 31, 2002 as if SFAS No. 143 had been adopted on January 1, 2000 (in thousands, except per share amounts):

	December 31, 2002
Net income:	
As reported	$31,579
Pro forma	30,419
Net income per share, as reported:	
Basic	$ 1.00
Diluted	$ 0.97
Net income per share, pro forma:	
Basic	$ 0.96
Diluted	$ 0.93

Income Taxes

Under 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.

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 settlements in volumes or cash, as required by applicable contracts. Imbalances included in accounts receivable were $0.9 million and $0.9 million as of December 31, 2004 and 2003, respectively. Imbalances included in accrued liabilities were $5.9 million and $4.1 million as of December 31, 2004 and 2003, respectively.

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 elected 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 and $0.2 million in 2004, 2003 and 2002, 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,		
	2004	2003	2002
Net income, as reported	$53,933	$36,612	$31,579
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	126	—	114
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(8,984)	(9,375)	(8,902)
Pro forma net income	$45,075	$27,237	$22,791
Net income per common share:			
Basic, as reported	$ 1.60	$ 1.10	$ 1.00
Basic, pro forma	$ 1.33	$ 0.82	$ 0.72
Diluted, as reported	$ 1.55	$ 1.08	$ 0.97
Diluted, pro forma	$ 1.26	$ 0.79	$ 0.70

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 and assumptions as follows:

	Year Ended December 31,		
	2004	2003	2002
Risk-free interest rate	2.70%-4.32%	3.18%-4.48%	3.98%-5.28%
Volatility factor	31.1%	31.7%	62.2%
Dividend yield	0%	0%	0%
Expected life of the options (years)	3.7	3.5	4.0

Financial Instruments and Price Risk Management Activities

At December 31, 2004, 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 oil and gas 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.

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 recorded a reserve of $3.2 million for its share of these receivables.

New Accounting Pronouncements

On September 28, 2004, the Commission released Staff Accounting Bulletin ("SAB") No. 106 regarding the application of SFAS No. 143, "Accounting for Asset Retirement Obligations," by oil and gas producing companies following the full cost accounting method. Pursuant to SAB No. 106, oil and gas producing companies that have adopted SFAS No. 143 should exclude the future cash outflows associated with the settlement of asset retirement obligations from the computation of the present value of estimated future net revenues for the purposes of the full cost ceiling calculation. In addition, estimated dismantlement and abandonment costs, net of estimated salvage values, that have been capitalized should be included in the amortization base for computing DD&A. Disclosures are required to include discussion of how a company's ceiling test and DD&A calculations are impacted by the adoption of SFAS No. 143. SAB No. 106 is effective prospectively as of the beginning of the first fiscal quarter beginning after October 4, 2004. Since our adoption of SFAS No. 143 on January 1, 2003, we have calculated the ceiling test and our DD&A in accordance with the interpretations set forth in SAB No. 106; therefore, the adoption of SAB No. 106 will have no effect on our consolidated financial statements.

On December 16, 2004, the FASB revised SFAS No. 123 (revised 2004), "Share-Based Payment," ("SFAS No. 123(R)") that will require compensation costs related to share-based payment transactions to be recognized in the financial statements. With limited exceptions, the amount of compensation cost will be measured based on the grant-date fair value of the equity or liability instruments issued. In addition, liability awards will be remeasured each reporting period. Compensation cost will be recognized over the period that an employee provides service in exchange for the award. SFAS No. 123(R) replaces SFAS No. 123 and supersedes APB Opinion No. 25. For the Company, SFAS No. 123(R) is effective for the first quarterly reporting period after

June 15, 2005. Adoption of SFAS No. 123(R) will require the Company to recognize compensation expense for all awards Spinnaker grants after the date of adoption and for the unvested portion of all options granted that remain outstanding on the date of adoption. All options that the Company granted prior to June 30, 2001 will be fully vested prior to adoption of SFAS No. 123(R) and will not be considered as part of the adoption in accordance with the new standard. The Company is currently evaluating the effect of adopting SFAS No. 123(R).

On December 16, 2004, the FASB issued SFAS No. 153, "Exchanges of Nonmonetary Assets," an amendment of APB Opinion No. 29, to clarify the accounting for nonmonetary exchanges of similar productive assets. SFAS No. 153 eliminates the exception from the fair value measurement for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. SFAS No. 153 will be applied prospectively and is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The Company does not expect the adoption of SFAS No. 153 to have a material impact on its consolidated financial statements.

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,	
	2004	2003
Accounts receivable:		
Natural gas and oil sales(1)	$33,880	$21,015
Joint interest billings	12,823	6,496
Insurance claims receivable	1,778	2,792
Hedging receivable(1)	2,093	2,093
Oil and gas imbalances	888	859
Other receivables	555	44
Allowance for doubtful accounts(1)	(3,232)	(3,232)
Total accounts receivable	$48,785	$30,067
Other current assets:		
Prepaid insurance	$ 1,408	$ 1,937
Deferred tax assets associated with hedging activities	—	972
Prepaid debt financing costs	575	575
Drilling advances	561	65
Other	923	644
Total other current assets	$ 3,467	$ 4,193
Accrued liabilities and other:		
Accrued liabilities	$41,334	$56,802
Oil and gas imbalances	5,930	4,072
Total accrued liabilities and other	$47,264	$60,874

(1) 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 recorded a reserve of $3.2 million for its share of these receivables.

4. Long-Term Debt:

On December 19, 2003, the Company's wholly-owned subsidiary, Spinnaker Exploration Company, L.L.C., entered into a $200.0 million revolving credit agreement (the "Revolver") with a group of eight banks. The Revolver consists of two tranches, Tranche A and Tranche B. Borrowings under each tranche constitute senior indebtedness. The obligations under the Revolver are fully and unconditionally guaranteed by Spinnaker.

Tranche A is available on a revolving basis through December 19, 2006, the maturity date of the Revolver, and availability is subject to the borrowing base determined by the banks. The borrowing base was $140.0 million as of December 31, 2004. Tranche B is $50.0 million, is available in multiple advances through April 1, 2005 and is not subject to the borrowing base. Borrowings under Tranche B cannot be reborrowed once repaid. Total availability under Tranche A and Tranche B cannot exceed $200.0 million. Should the borrowing base exceed $150.0 million, Tranche B would be reduced by a like amount for the period the borrowing base exceeds $150.0 million until the maturity of Tranche B. The obligations under Tranche A are unsecured. At such time Tranche B is utilized, the banks are to be provided with security interests in virtually all of Spinnaker's reserve base. Upon repayment of Tranche B, the security interests are to be released.

The borrowing base is re-determined semi-annually by the banks in their sole discretion and in their usual and customary manner. Spinnaker and the banks also have the right to request one additional re-determination annually. The amount of the borrowing base is a function of the banks' view of Spinnaker's reserve profile, future commodity prices and projected cash flows. In addition to the semi-annual re-determinations, the banks have the right to re-determine the borrowing base in the event of the sale, transfer or disposition of assets included in the borrowing base exceeding $25.0 million, or $10.0 million when Tranche B is utilized.

The Company has the option to elect to use a base interest rate as described below or the London Interbank Offered Rate ("LIBOR") plus, for each such rate, a spread based on the percentage of the borrowing base used at that time. The base rate spread ranges from 0.0% to 0.5% for Tranche A borrowings and from 2.0% to 2.75% for Tranche B borrowings. The LIBOR spread ranges from 1.25% to 2.0% for Tranche A borrowings and from 3.0% to 3.75% for Tranche B borrowings. The base interest rate under the Revolver is a fluctuating rate of interest equal to the base rate spread plus the higher of either (i) The Toronto-Dominion Bank's base rate for dollar advances made in the United States or (ii) the Federal Funds Rate plus 0.5% per annum. The weighted average interest rate was 3.28% in 2004. The commitment fee rate ranges from 0.375% to 0.5%, depending on the borrowing base usage for Tranche A, and is 0.625% for Tranche B.

The Revolver also includes the following restrictions and covenants:

- Incurrence of other debt is prohibited except that senior debt may not exceed $10.0 million ($5.0 million when Tranche B is used), vendor indebtedness for the purchase of seismic data may not exceed $25.0 million, subordinated debt is permitted subject to certain conditions and a lease transaction involving the Front Runner spar production facility is specifically permitted.
- Liens are generally prohibited; however, the Company may grant a lien in connection with the purchase of seismic data, pledges and deposits to secure hedging arrangements not to exceed $15.0 million and lease financing arrangements involving the Company's interest in the Front Runner spar production facility.
- Stock buy-backs exceeding $10.0 million are prohibited in any fiscal year.
- The ratio of debt to EBITDA may not exceed 2.50 to 1.00.
- The ratio of current assets to current liabilities may not be less than 1.00 to 1.00. For purposes of the calculation, availability under the Revolver is added to current assets and maturities of the Revolver are

excluded from current liabilities. Hedging assets and liabilities and asset retirement obligations are also excluded from this calculation.

- The Company's tangible net worth is required to exceed 80% of the level at September 30, 2003, plus 50% of future net income with certain non-cash gains and losses excluded from net income, plus 75% of future equity issuances.
- The Company's hedging transactions must not exceed 66⅔% of estimated future production for the next 18 months and 33⅓% for the period 19 to 36 months from the date of the transaction. There are also credit rating restrictions on counterparties as well as concentration limits.

On February 8, 2005, Spinnaker and the banks amended the Revolver. The amendment was intended to give the Company:

- the flexibility to engage in business activities through entities other than its subsidiary, Spinnaker Exploration Company, L.L.C., including activities in international locations;
- the ability to make investments and provide guarantees and extensions of credit to entities other than its subsidiary;
- a basket of up to $75.0 million a year to make distributions from its subsidiary to Spinnaker, to request letters of credit under the Revolver for activities other than those of its subsidiary, subject to the limits under the Revolver, and to provide extensions of credit from its subsidiary to other entities; and
- an increase in the aggregate amount of the borrowing base available under the Revolver for letters of credit up to $60.0 million, subject to certain limitations.

As of December 31, 2004, the Company had outstanding borrowings of $105.0 million. Current availability is $35.0 million and $50.0 million under Tranche A and Tranche B, respectively. As of December 31, 2004, the Company was not in technical compliance with certain provisions of the Revolver related to the new subsidiaries we formed for our first international venture offshore Nigeria. However, as a result of the amendment to the Revolver on February 8, 2005, the Company is now in compliance with the provisions of the Revolver. Subsequent to December 31, 2004, Spinnaker has had no additional borrowings under the Revolver, but the Company expects to incur additional borrowings in 2005.

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:

Officers, directors and employees have been granted options to purchase Common Stock under stock plans adopted in 1998, 1999, 2000, 2001 and 2003. Stock option grants generally vest ratably over four years, with 20% vesting on the date of grant and 20% vesting on the anniversary date of the grant in each of the succeeding four years. In the event of certain significant changes in control of the Company, all options then outstanding generally will become immediately exercisable in full. Following is a description of the major provisions of each stock plan.

2003 Stock Option Plan ("2003 Plan")

Stockholders approved the 2003 Plan in May 2003. The number of shares of Common Stock that may be issued under the 2003 Plan may not exceed 1,650,000 shares. The exercise price of each option equals 105% of the fair market value of Spinnaker's Common Stock on the date of grant. The maximum number of shares of Common Stock that may be subject to awards granted under the 2003 Plan to any one individual during any calendar year may not exceed 300,000 shares. The options expire after five years.

2001 Stock Incentive Plan ("2001 Plan")

Stockholders approved the 2001 Plan in May 2001. The number of shares of Common Stock that may be issued under the 2001 Plan may not exceed 1,500,000 shares. The exercise price of each option equals the fair market value of Spinnaker's Common Stock on the date of grant. 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. The options expire after ten years.

2000 Stock Option Plan ("2000 Plan")

The Board of Directors of Spinnaker adopted the 2000 Plan in November 2000. 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. The exercise price of each option equals the fair market value of Spinnaker's Common Stock on the date of grant. The options expire after ten years.

1999 Stock Incentive Plan ("1999 Plan")

Stockholders approved the 1999 Plan in September 1999. The number of shares of Common Stock that may be issued under the 1999 Plan may not exceed 1,300,000 shares. The exercise price of each option equals the fair market value of Spinnaker's Common Stock on the date of grant. 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. The options expire after ten years.

Adjunct Stock Option Plan ("Adjunct Plan")

Stockholders approved the Adjunct Plan in connection with the 1999 Plan. The number of shares of Common Stock that may be issued under the Adjunct Plan may not exceed 21,920. The exercise price of each option equals the fair market value of Spinnaker's Common Stock on the date of grant. The options expire after ten years.

1998 Stock Option Plan ("1998 Plan")

Stockholders approved the 1998 Plan in January 1998. The 1998 Plan was amended and restated in September 1999 and authorized the issuance of 2,673,242 shares of Common Stock. The exercise price of each option equals the fair market value of Spinnaker's Common Stock on the date of grant. The options expire after ten years.

Presented below is a summary of stock option activity.

	2004		2003		2002	
	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weighted Average Exercise Price
Outstanding, beginning of year	5,430,903	$24.19	4,386,533	$23.87	4,062,556	$22.08
Granted	582,150	36.60	1,288,000	23.81	450,000	35.82
Exercised	(532,526)	17.23	(186,961)	11.43	(119,433)	8.01
Forfeited	(117,684)	34.52	(56,669)	32.26	(6,590)	27.64
Outstanding, end of year	5,362,843	$26.00	5,430,903	$24.19	4,386,533	$23.87
Exercisable, end of year	3,816,983	$24.10	3,558,639	$21.66	2,845,250	$19.30
Available for grant, end of year	158,738		623,204		204,535	
Weighted average fair value of options granted during the year	$ 11.05		$ 7.78		$ 26.83	

The Company transferred treasury shares to certain employees in connection with their exercises of 3,264, 2,300 and 2,944 options in 2004, 2003 and 2002, 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, 2004, 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	407,505	$ 4.96	407,505	$ 4.96	2.2
$14.50-$16.13	1,300,778	15.38	1,300,778	15.38	3.7
$21.58-$28.16	1,443,700	24.20	720,700	24.75	4.5
$30.38-$36.81	316,900	33.73	148,300	33.32	6.1
$37.04-$38.63	1,731,160	37.67	1,116,500	37.80	5.8
$39.35-$42.06	162,800	40.46	123,200	40.57	6.7
	5,362,843		3,816,983		

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,		
	2004	2003	2002
Numerator:			
Net income available to common stockholders	$53,933	$36,612	$31,579
Denominator:			
Basic weighted average number of shares	33,771	33,234	31,695
Dilutive securities:			
Stock options	1,036	646	958
Diluted adjusted weighted average number of shares and assumed conversions	34,807	33,880	32,653
Net income per common share:			
Basic	$ 1.60	$ 1.10	$ 1.00
Diluted	$ 1.55	$ 1.08	$ 0.97

For the years ended December 31, 2004, 2003 and 2002, 2,010,360, 2,361,630 and 1,680,640 stock options that could potentially dilute earnings per share are excluded from the calculations as they were anti-dilutive.

8. Major Customers:

For the year ended December 31, 2004, sales to Cinergy Marketing & Trading, LP, Shell Trading (US) Company and Sequent Energy Management, L.P. accounted for approximately 50%, 22% and 16%, respectively, of total oil and gas revenues, excluding the effects of hedging activities. For the year ended December 31, 2003, sales to Cinergy Marketing & Trading, LP, Sequent Energy Management, L.P., Shell Trading (US) Company and Duke Energy Trade and Marketing LLC accounted for approximately 41%, 22%, 14% and 10%, respectively, of total oil and gas revenues, excluding the effects of hedging activities. 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 total oil and gas revenues, excluding the effects of hedging activities.

9. Related-Party Transactions:

The Company purchases oilfield goods, equipment and services from Baker Hughes Incorporated ("Baker Hughes"), Cooper Cameron Corporation ("Cooper Cameron"), National-Oilwell, Inc. ("National-Oilwell") and other oilfield services companies in the ordinary course of business. Spinnaker incurred charges of approximately $13.5 million, $7.5 million and $16.1 million in 2004, 2003 and 2002, respectively, from affiliates of Baker Hughes. Mr. Michael E. Wiley, a director of Spinnaker, served as Chairman of the Board and Chief Executive Officer of Baker Hughes through October 25, 2004. Spinnaker incurred charges of approximately $0.1 million in each of 2004, 2003 and 2002 from Cooper Cameron. Mr. Sheldon R. Erikson, a director of Spinnaker, serves as Chairman of the Board, Chief Executive Officer and President of Cooper Cameron. Spinnaker incurred charges of approximately $0.1 million, $0.1 million and $0.2 million in 2004, 2003 and 2002, respectively, from National-Oilwell. Mr. Roger L. Jarvis, Chairman of the Board, Chief Executive Officer and President of

Spinnaker, has served as a director of National-Oilwell since February 2002. These amounts represent less than 1% of Baker Hughes', Cooper Cameron's and National-Oilwell's total revenues in 2004, 2003 and 2002 and only reflect charges directly incurred by the Company. The Company's partners may incur charges from these related parties that are not included above.

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. Each of these companies is a leader in their respective segments of the oilfield services sector. The Company could be at a disadvantage if it were to discontinue using these companies as vendors.

10. Income Taxes:

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

	As of December 31, 2004	As of December 31, 2003
Deferred income tax liabilities:		
Basis differences in oil and gas properties	$234,183	$183,350
Hedging activities	432	—
Total deferred income tax liabilities	234,615	183,350
Deferred income tax assets:		
Net operating losses	124,043	96,298
Hedging activities	—	972
Other	2,364	6,025
Total deferred income tax assets	126,407	103,295
Net deferred income tax liabilities	108,208	80,055
Deferred tax assets/(liabilities) reported in other current assets/(liabilities)	(432)	972
Deferred income taxes	$107,776	$ 81,027

Tax benefits of approximately $3.6 million and $1.0 million associated with the exercise of non-qualified stock options during the years ended December 31, 2004 and 2003 are reflected as a component of equity. The net deferred income tax liabilities include current deferred tax liabilities of $0.4 million and deferred tax assets of $1.0 million related to the tax effect of the fair market value of derivatives as of December 31, 2004 and 2003, respectively, as required by SFAS No. 133, as amended. Upon adoption of SFAS No. 143 on January 1, 2003, the Company recorded a cumulative effect of change in accounting principle of $3.5 million, net of taxes of $2.0 million.

As of December 31, 2004, the Company had approximately $344.6 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,		
	2004	2003	2002
Current	$ —	$ 440	$ (300)
Deferred	30,337	22,138	18,063
Income tax expense	$30,337	$22,578	$17,763

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,		
	2004	2003	2002
Federal income tax expense at statutory rates	$29,495	$21,951	$17,270
Non-deductible expenses and other	842	627	493
Income tax expense	$30,337	$22,578	$17,763

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. The expense associated with the Company match of participant contributions was $0.4 million, $0.4 million and $0.3 million in 2004, 2003 and 2002, respectively. In connection with the Company match of participant contributions, the Company issued 12,648, 16,124 and 9,062 shares of Common Stock in 2004, 2003 and 2002, respectively.

Leases

The Company leases administrative offices under a non-cancelable operating lease expiring in 2007. The lease agreement requires the Company to 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 $2.1 million, $2.2 million and $1.6 million in 2004, 2003 and 2002, respectively. Minimum future obligations under non-cancelable operating leases as of December 31, 2004 for the next five years are approximately $1.3 million, $1.3 million, $0.5 million and less than $0.1 million thereafter, respectively.

Summary of Contractual Obligations

The Company leases administrative offices, office equipment and oil and gas equipment under non-cancelable operating leases. Contractual obligations as of December 31, 2004 were as follows (in thousands):

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt obligations	$105,000	$ —	$105,000	$ —	$ —
Operating lease obligations	3,154	1,306	1,839	9	—
Other contractual obligations	25,763	—	5,153	10,305	10,305
Total	$133,917	$1,306	$111,992	$10,314	$10,305

Other contractual obligations of $25.8 million relate to facility and pipeline demand charges associated with the production capacity commitment for the Company's natural gas discoveries in the Eastern Gulf of Mexico at DeSoto Canyon Blocks 618/619/620/621. The Company will incur obligations in the ordinary course of business under purchase and service agreements that are not included in the table above. These obligations, among others, include estimated future development costs of approximately $209.3 million for the costs of drilling additional wells, completions, recompletions, platforms, pipelines, facilities, tie-backs and abandonments related to the Company's proved reserves. The Company's asset retirement obligations as of December 31, 2004 were $40.5 million.

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 natural gas swap contracts and collar arrangements will settle based on the reported settlement price on the NYMEX for the last trading day of each month. The crude oil swap contracts and collar arrangements will settle based on the average of the settlement price for each commodity business day in the contract month.

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. Spinnaker 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. 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. Spinnaker 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 and ceiling prices. As of December 31, 2004, Spinnaker's commodity price risk management positions in swap contracts and collar arrangements were as follows:

Natural Gas

Period	Fixed Price Swaps		Collars		
	Average Daily Volume (MMBtus)	Weighted Average Price (Per MMBtu)	Average Daily Volume (MMBtus)	Weighted Average Price (Per MMBtu) Floor	Ceiling
First Quarter 2005	20,000	$7.76	—	$—	$—

Oil

Period	Fixed Price Swaps		Collars		
	Average Daily Volume (Bbls)	Weighted Average Price (Per Bbl)	Average Daily Volume (Bbls)	Weighted Average Price (Per Bbl) Floor	Ceiling
Calendar 2005	1,000	$40.34	3,000	$38.67	$44.73

The Company reported a net asset of $1.2 million and a net liability of $2.7 million related to financial derivative contracts as of December 31, 2004 and 2003, respectively. Amounts related to hedging activities were as follows (in thousands):

	As of December 31,	
	2004	2003
Current assets:		
Hedging assets	$2,829	$ 203
Deferred tax asset related to hedging activities	—	972
Current liabilities:		
Hedging liabilities	$1,628	$ 2,903
Deferred tax liability related to hedging activities	432	—
Equity:		
Accumulated other comprehensive income (loss)	$ 963	$(1,728)

The ineffective component of the derivatives and net hedging gains (losses) were recorded in revenues in 2004, 2003 and 2002 as follows (in thousands):

	Year Ended December 31,		
	2004	2003	2002
Ineffective component of derivatives	$ (194)	$ —	$ —
Net hedging income (loss)	$(7,502)	$(37,717)	$4,664

Based on future oil and gas prices as of December 31, 2004, the Company would reclassify a net gain of approximately $1.0 million from accumulated other comprehensive income (loss) to earnings in 2005. The amounts ultimately reclassified into earnings will vary due to changes in the fair value of the open derivative contracts prior to settlement.

13. Quarterly Financial Data (Unaudited):

Quarterly operating results for the years ended December 31, 2004 and 2003 are summarized as follows (in thousands, except per share amounts):

	(Unaudited) Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2004:				
Revenues	$59,791	$79,824	$63,191	$70,082
Income from operations	21,643	27,776	15,419	20,443
Net income	13,737	17,605	9,077	13,514
Net income per common share:				
Basic	$ 0.41	$ 0.52	$ 0.27	$ 0.40
Diluted	$ 0.40	$ 0.51	$ 0.26	$ 0.39
2003:				
Revenues	$71,671	$55,931	$50,138	$49,110
Income from operations	29,498	15,760	7,720	10,182
Net income	15,298	10,028	4,822	6,464
Net income per common share:				
Basic	$ 0.46	$ 0.30	$ 0.15	$ 0.19
Diluted	$ 0.45	$ 0.30	$ 0.14	$ 0.19

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

The following information related to the Company's oil and gas operations has been provided pursuant to SFAS No. 69, "Disclosures about Oil and Gas Producing Activities." The Company's oil and gas producing activities disclosed in the following information were conducted offshore in federal and Texas state waters of the Gulf of Mexico.

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

	As of December 31,	
	2004	2003
Capitalized costs:		
Proved properties	$1,447,824	$1,175,443
Unproved properties not being amortized	148,277	155,273
Total	1,596,101	1,330,716
Accumulated depreciation, depletion and amortization(1)	(536,917)	(394,004)
Net capitalized costs	$1,059,184	$ 936,712

(1) DD&A per Mcfe was $3.09, $2.56 and $2.12 in 2004, 2003 and 2002, respectively. The cumulative effect of change in accounting principle in 2003 included an impact to accumulated DD&A of approximately $0.9 million.

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

	Year Ended December 31, 2004	2003	2002
Acquisition costs:			
Unproved	$ 15,915	$ 20,067	$ 39,789
Proved	—	—	—
Exploration costs	150,062	104,362	166,382
Development costs	99,275	181,486	139,368
Total costs incurred	$265,252	$305,915	$345,539

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, and geological and geophysical service costs. Development costs include the costs of drilling development wells, completions, platforms, facilities, pipelines and the costs related to the retirement of these costs. Development costs include asset retirement costs of $6.5 million and $30.0 million in 2004 and 2003, respectively, and gain on settlement of asset retirement obligations of $0.1 million and $0.5 million in 2004 and 2003, respectively.

Additions to Unproved Properties and Properties Under Development (In thousands)

	Costs Incurred for the Year Ended December 31, Total	2004	2003	2002	2001 and Prior
Leasehold acquisition costs	$ 91,589	$16,520	$12,603	$24,910	$37,556
Exploration and development costs	56,688	27,924	8,759	9,715	10,290
Total	$148,277	$44,444	$21,362	$34,625	$47,846

Unevaluated properties includes no individually significant properties or significant development projects. The Company estimates that the majority of the costs will be evaluated within five years.

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

	Year Ended December 31, 2004	2003	2002
Revenues	$272,888	$226,850	$188,326
Operating expenses(1)	24,633	22,489	18,212
Depreciation, depletion and amortization	142,913	125,331	108,998
Accretion expense	3,054	2,251	—
Gain on settlements of asset retirement obligations	(133)	(464)	—
Charges related to Enron bankruptcy	—	—	128
Income tax expense(2)	36,872	27,807	21,956
Results of operations	$ 65,549	$ 49,436	$ 39,032

(1) Operating expenses include costs incurred to operate and maintain wells and related equipment and facilities. These costs include, among others, workover expenses, labor, materials, supplies, property taxes, insurance, severance taxes and transportation, gathering and processing 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 oil and gas 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 oil and gas 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, 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
Extensions, discoveries and other additions	53,775	1,867	64,976
Revisions of previous estimates(3)	(2,350)	(769)	(6,962)
Production	(40,527)	(1,414)	(49,010)
Proved reserves as of December 31, 2003(1)	154,429	29,692	332,581
Extensions, discoveries and other additions	31,738	1,502	40,752
Revisions of previous estimates(4)	(3,872)	(2,758)	(20,423)
Production	(35,729)	(1,743)	(46,188)
Proved reserves as of December 31, 2004(1)	146,566	26,693	306,722
Proved developed reserves:			
December 31, 2004	59,717	7,631	105,500
December 31, 2003	76,181	4,877	105,441
December 31, 2002	84,139	2,219	97,456
December 31, 2001	82,221	748	86,711

(1) Spinnaker has a 25% non-operator working interest in a significant deepwater oil discovery at Front Runner. Proved oil and condensate reserves were 52%, 53% and 56% of total proved reserves as of December 31, 2004, 2003 and 2002, respectively. Of the Company's total proved reserves as of December 31, 2004, 66% were proved undeveloped reserves. Front Runner represented approximately 67% 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 were added in the Front Runner area, changes in future production assumptions resulted in a reallocation of proved reserves subject to royalty relief. These reallocations resulted in

downward revisions of 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 the beginning of the year.

(3) The 2003 revisions of previous estimates include a 6.1 Bcfe downward revision on Mississippi Canyon 496 (Zia) related to reserves originally booked below lowest known hydrocarbon. No downward revision on any individual property exceeded 2% of proved reserves as of the beginning of the year.

(4) Of the 20.4 Bcfe net downward revision of previous estimates, 14.3 Bcfe, or 70%, related to the retraction of royalty suspension volumes at Front Runner. The Minerals Management Service allows royalty relief under the Deep Water Royalty Relief Act subject to certain oil and gas price thresholds on eligible leases in the Gulf of Mexico. Front Runner area reserves are subject to royalty relief on the first 87.5 million equivalent barrels of oil produced. If the average annual NYMEX oil and gas prices exceed the price thresholds, royalty suspension volumes are retracted in that year. Average oil and gas prices have exceeded these thresholds in recent years and in 2004 for certain leases.

At the end of each period, reserves are estimated based on oil and gas prices then in effect. Prior to June 30, 2004, Spinnaker's share of gross Front Runner reserves excluded natural gas royalty suspension volumes and included oil royalty suspension volumes. Based on the average oil price as of June 30, 2004, the Company believed that the thresholds would be exceeded and the leases would not qualify for royalty relief. As a result, the Company incurred a downward reserve revision of approximately 2.4 million barrels, or 14.3 Bcfe, in the second quarter of 2004. The remaining net downward reserve revision was 6.1 Bcfe. No downward reserve revision on any individual property exceeded 4% of proved reserves as of the beginning of the year.

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 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 oil and gas producing activities and tax carryforwards.

The standardized measure of discounted future net cash flows is not intended to represent the fair market value of the Company's proved 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 oil and gas prices, it is reasonably possible that the Company's estimate of discounted future net cash flows from proved oil and gas reserves will change in the near term. If oil and gas 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 oil and gas properties could occur in the future.

SPINNAKER EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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

	Year Ended December 31,		
	2004	2003	2002
Future cash inflows(1)	$1,918,400	$1,867,760	$1,613,724
Future operating expenses	(200,746)	(219,466)	(185,782)
Future development costs	(209,292)	(177,531)	(184,441)
Future net cash flows before income taxes	1,508,362	1,470,763	1,243,501
Future income taxes	(395,913)	(373,295)	(259,436)
Future net cash flows	1,112,449	1,097,468	984,065
10% annual discount	(324,860)	(293,687)	(303,267)
Standardized measure of discounted future net cash flows	$ 787,589	$ 803,781	$ 680,798

(1) *Prices for natural gas and oil used to calculate future cash inflows were* $6.38, $6.29 and $4.91 per Mcf of natural gas and $37.25, $30.34 and $30.50 per barrel of oil as of December 31, 2004, 2003 and 2002, respectively.

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

	Year Ended December 31,		
	2004	2003	2002
Standardized measure, beginning of year	$ 803,781	$ 680,798	$ 329,556
Extensions and discoveries, net of related costs	124,142	212,129	215,800
Sales of natural gas and oil produced, net of production costs	(255,757)	(242,078)	(165,450)
Net changes in prices and production costs	152,646	115,793	403,728
Change in future development costs	(21,048)	(3,816)	(26,795)
Development costs incurred during the period that reduced future development costs	69,412	77,604	56,831
Revisions of quantity estimates	(93,955)	(22,578)	(57,991)
Accretion of discount	89,817	76,169	(640)
Net change in income taxes	2,512	(94,391)	(80,892)
Change in production rates and other	(83,961)	4,151	6,651
Standardized measure, end of year	$ 787,589	$ 803,781	$ 680,798

EXHIBIT INDEX

Exhibit Number	Description
3.1	—Certificate of Incorporation of Spinnaker, as amended (incorporated by reference to Exhibit 3.1 to 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 Spinnaker's 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 Registration Statement on Form S-1 (Commission File No. 333-83093))
10.2	—Amended and Restated 1998 Stock Option Plan (incorporated by reference to Exhibit 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. Hubbard, Kelly M. Barnes and certain other stockholders of Spinnaker (including the Registration Rights Agreement as Exhibit A to the Stockholders Agreement) (incorporated by reference to Exhibit 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 Spinnaker, Warburg, Pincus Ventures, Petroleum Geo-Services, Roger L. Jarvis, James M. Alexander, William D. Hubbard, Kelly M. Barnes and certain other stockholders of Spinnaker (incorporated by reference to Exhibit 10.3.1 to Spinnaker's Quarterly Report on Form 10-Q for the quarter ended June 30, 2000)
10.4	—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 Statement on Form S-1 (Commission File No. 333-83093))
10.5	—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 Statement on Form S-1 (Commission File No. 333-83093))
10.6	—1999 Stock Incentive Plan (incorporated by reference to Exhibit 10.10 to Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
10.7	—1999 Employee Stock Purchase Plan (incorporated by reference to Exhibit 10.11 to Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
10.8	—Form of Indemnification Agreement (incorporated by reference to Exhibit 10.12 to Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
10.9	—Adjunct Stock Option Plan (incorporated by reference to Exhibit 4.3 to Spinnaker's Registration Statement on Form S-8 (Commission File No. 333-36592))
10.10	—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, 2000)
10.11	—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 File No. 333-61888))

Exhibit Number	Description
10.12	—Spinnaker Exploration Company 2003 Stock Option Plan (incorporated by reference to Exhibit 10.1 to Spinnaker's Registration Statement on Form S-8 (Commission File No. 333-105461))
10.13	—Credit Agreement for a $200 million credit facility dated as of December 19, 2003 (incorporated by reference to Exhibit 10.14 to Spinnaker's Annual Report on Form 10-K for the year ended December 31, 2003)
10.13.1*	—Omnibus Amendment to Credit Agreement and Guaranty dated as of February 8, 2005
10.14	—Guaranty dated as of December 19, 2003 made by Spinnaker Exploration Company (incorporated by reference to Exhibit 10.15 to Spinnaker's Annual Report on Form 10-K for the year ended December 31, 2003)
10.15	—Guaranty dated as of December 19, 2003 made by WP Spinnaker Holdings, Inc. (incorporated by reference to Exhibit 10.16 to Spinnaker's Annual Report on Form 10-K for the year ended December 31, 2003)
10.16*	—Non-Employee Director Compensation Arrangement
12.1*	—Calculation of Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends
21.1*	—Subsidiaries of Spinnaker Exploration Company
23.1*	—Consent of KPMG LLP
23.2*	— Consent of Ryder Scott Company, L.P.
31.1*	—Certification of Principal Executive Officer of Spinnaker Exploration Company Pursuant to Section 302 of the Sarbanes-Oxley Act
31.2*	—Certification of Principal Financial Officer of Spinnaker Exploration Company Pursuant to Section 302 of the Sarbanes-Oxley Act
32.1*	—Certification of Chief Executive Officer of Spinnaker Exploration Company Pursuant to 18 U.S.C. § 1350
32.2*	—Certification of Chief Financial Officer of Spinnaker Exploration Company Pursuant to 18 U.S.C. § 1350

* Filed herewith.

NOTES

Board of Directors

Roger L. Jarvis
Chairman of the Board, President and
Chief Executive Officer
Spinnaker Exploration Company

Walter R. Arnheim (1)
Former Treasurer
Mobil Corporation

Sheldon R. Erikson (2) (3) (4)
Chairman of the Board, President and
Chief Executive Officer
Cooper Cameron Corporation

Jeffrey A. Harris (2) (4)
Managing Director / Partner
Warburg Pincus LLC / Warburg Pincus & Co.

Michael E. McMahon (1) (4) (6)
Executive Director
Rhode Island Economic Development Corporation

Howard H. Newman (3) (5)
Vice Chairman / Partner
Warburg Pincus LLC / Warburg Pincus & Co.

Michael E. Wiley (1) (2)
Former Chairman of the Board and
Chief Executive Officer
Baker Hughes Incorporated

(1) Audit Committee
(2) Compensation Committee
(3) Nominating / Corporate Governance Committee
(4) Committee Chairman
(5) Presiding Director
(6) Audit Committee Financial Expert

Corporate Officers

Roger L. Jarvis
Chairman of the Board, President and
Chief Executive Officer

Scott A. Griffiths
Executive Vice President and
Chief Operating Officer

Robert M. Snell
Vice President, Chief Financial Officer
and Secretary

Kelly M. Barnes
Vice President – Land

Jimmy W. Bennett
Vice President – Systems Technology
and Processing

L. Scott Broussard
Vice President – Drilling and Production

Gonzalo Enciso
Vice President and Chief Geoscientist

William N. Young, III
Vice President – Marketing

Jeffrey C. Zaruba
Vice President, Treasurer and Assistant Secretary

CORPORATE ADDRESS

1200 Smith Street, Suite 800
Houston, Texas 77002
Phone (713) 759-1770 — Fax (713) 759-1773
ske@spinexp.com — www.spinnakerexploration.com

TRANSFER AGENT

Computershare Trust Company, Inc.
350 Indiana Street, Suite 800
Golden, Colorado 80401
(303) 262-0600

OUTSIDE LEGAL COUNSEL

Vinson & Elkins L.L.P. — Houston, Texas

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

KPMG LLP — Houston, Texas

AVAILABLE INFORMATION

Our annual reports 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 Securities and Exchange Commission ("Commission") pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, are made available, free of charge, on our internet website at www.spinnakerexploration.com as soon as reasonably practicable after we electronically file or furnish such material with or to the Commission. The public may also read and copy any materials that we file with the Commission at the Commission's Public Reference Room at 450 Fifth Street, NW, Washington, DC 20549.

Our Board of Directors has adopted Corporate Governance Guidelines, a Code of Business Conduct and Ethics, a Financial Code of Ethics and charters for our Audit, Compensation and Nominating/Corporate Governance Committees. Each of these documents is available on our internet website at www.spinnakerexploration.com and available in print free of charge, upon written request to Spinnaker Exploration Company, 1200 Smith Street, Suite 800, Houston, Texas 77002, Attention: Corporate Secretary.

CERTIFICATIONS

We submitted a Section 303A.12(a) CEO Certification to the New York Stock Exchange in 2004. We also filed with the Securities and Exchange Commission the Chief Executive Officer and Chief Financial Officer certifications required under Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 and 31.2, respectively, to our Form 10-K filed on March 15, 2005.

MARKET INFORMATION

Our 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	LOW
2003:		
First Quarter	$ 22.70	$ 17.15
Second Quarter	$ 28.01	$ 18.01
Third Quarter	$ 26.50	$ 19.98
Fourth Quarter	$ 33.52	$ 23.97
2004:		
First Quarter	$ 36.99	$ 31.93
Second Quarter	$ 39.50	$ 30.80
Third Quarter	$ 40.60	$ 31.07
Fourth Quarter	$ 37.00	$ 30.65
2005:		
First Quarter (through March 11, 2005)	$ 39.30	$ 31.50

As of March 11, 2005, there were 28 holders of record of our common stock.

ANNUAL MEETING

The Company's annual meeting of stockholders will be held at 9:00 a.m. on Wednesday, May 4, 2005, at the DoubleTree Hotel at Allen Center, 400 Dallas Street at Bagby, Houston, Texas.

SPINNAKER EXPLORATION COMPANY

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