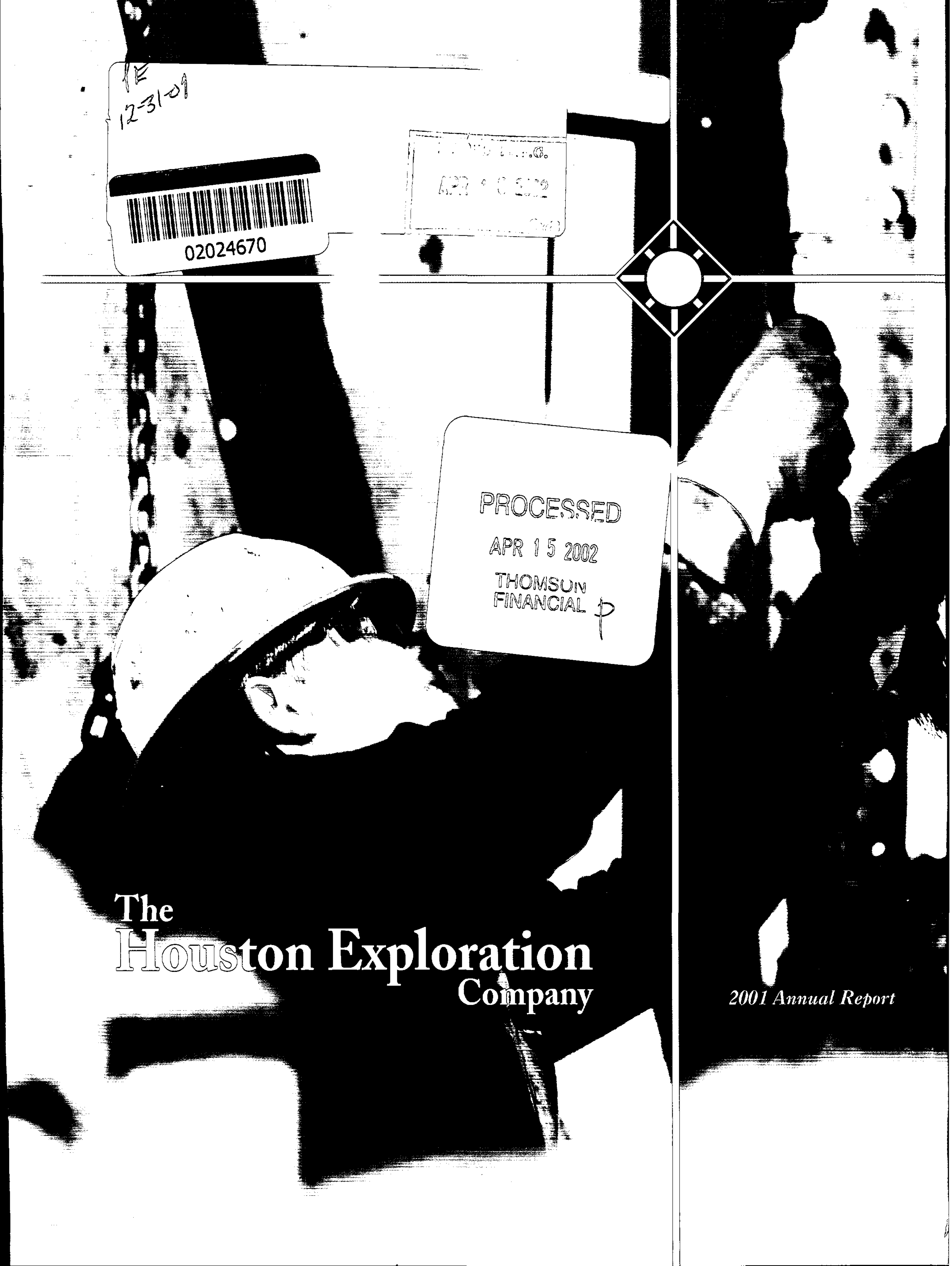
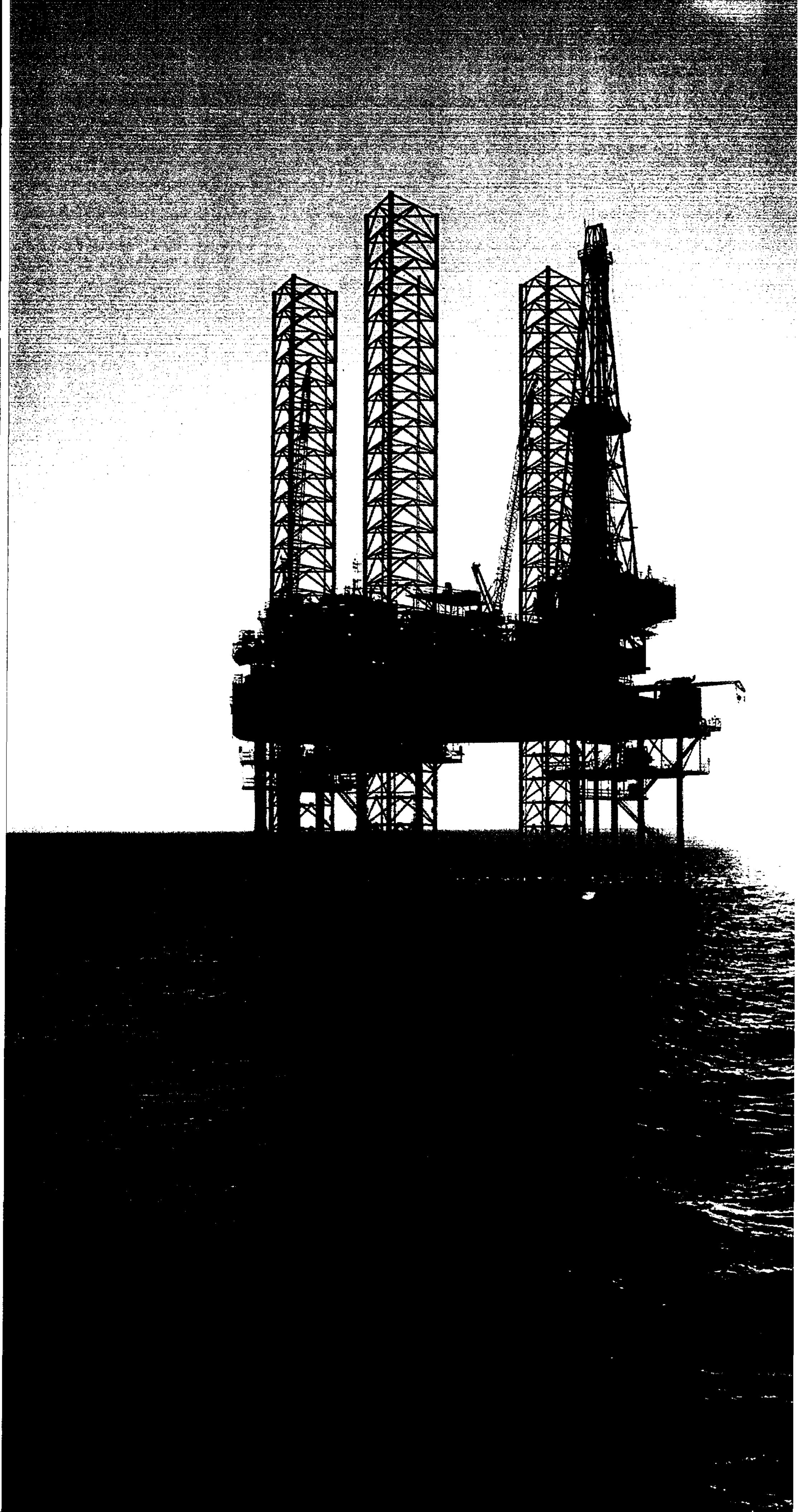
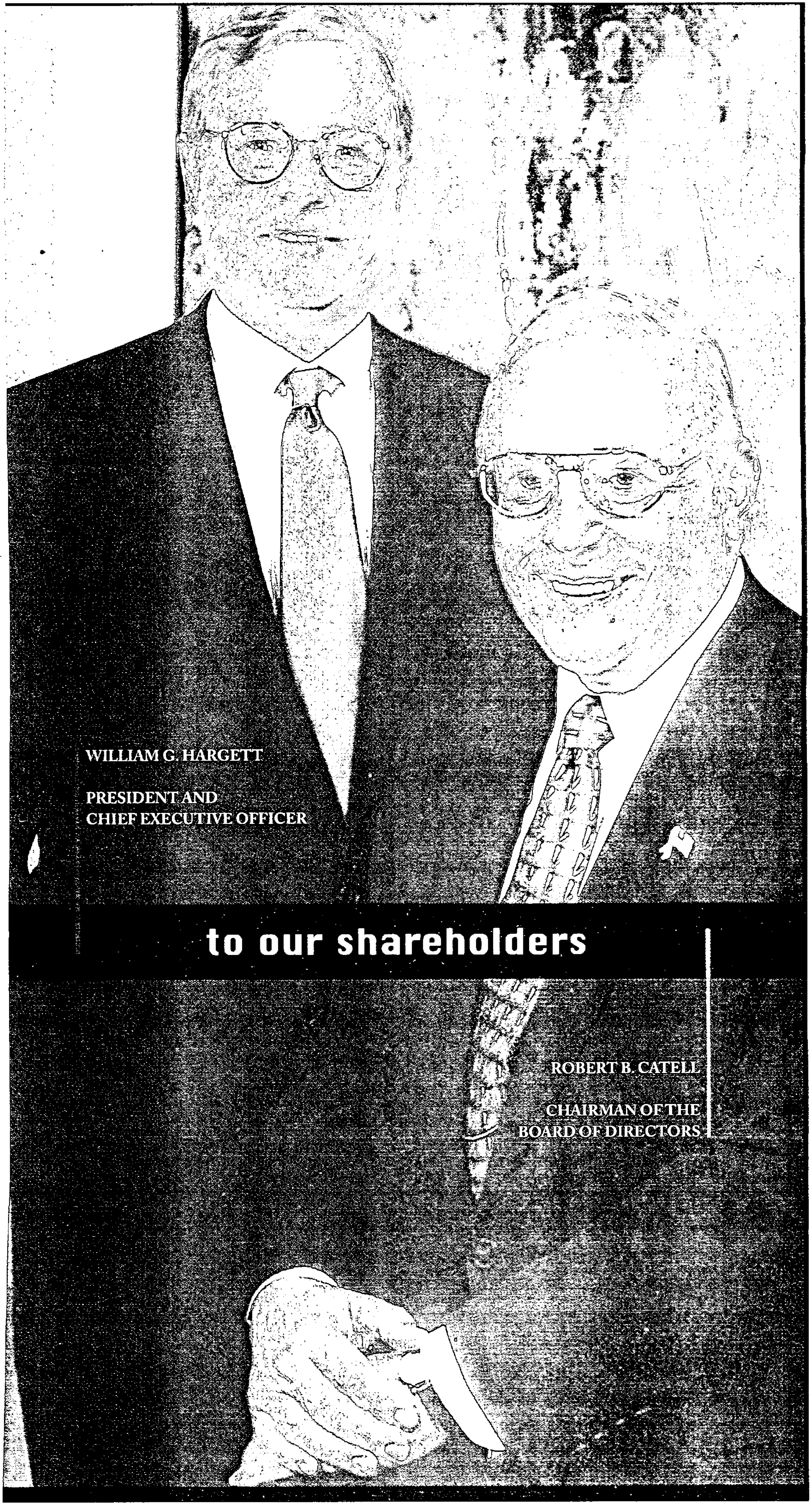


The Houston Exploration Company

2001 Annual Report

The Houston Exploration Company (NYSE: THX), headquartered in Houston, Texas began in 1986 as an exploration and production company focused principally on the offshore Gulf of Mexico region. Today, Houston Exploration produces primarily in the Gulf of Mexico, South Texas, the Arkoma Basin and West Virginia, and explores primarily in the Gulf of Mexico shelf and South Texas. Significant growth potential has come through the Company's extensive lease inventory in the Gulf of Mexico. The inventory of offshore high-potential exploratory prospects is complemented by the inventory of lower risk development and exploitation drilling opportunities onshore. Houston Exploration's operating strategy of having concentrated assets, a high working interest, and a high rate of operatorship has resulted in one of the lowest cost operating structures in the sector. At year-end 2001 the Company's reserves were 93% natural gas. The Houston Exploration Company entered the public market in 1996 and is traded on the New York Stock Exchange under the symbol THX.





WILLIAM G. HARGETT

PRESIDENT AND
CHIEF EXECUTIVE OFFICER

to our shareholders

ROBERT B. CATELL

CHAIRMAN OF THE
BOARD OF DIRECTORS

Performance *Highlights*

FINANCIAL HIGHLIGHTS

(In thousands of dollars except per-share data)

	Years Ended December 31, 2001	2000	1999
Revenue	$ 380,857	$ 272,333	$ 151,727
Net income	$ 122,601	$ 85,258	$ 24,621
Earnings per share-fully diluted	$ 4.00	$ 3.02	$ 0.95
Discretionary cash flow[1][2]	$ 313,108	$ 204,061	$ 103,708
Discretionary cash flow per share-fully diluted	$ 10.22	$ 7.23	$ 3.66
Total Assets	$1,059,092	$ 837,384	$ 678,483
Total long-term debt and notes	$ 244,000	$ 245,000	$ 281,000
Shareholders' equity	$ 565,881	$ 396,742	$ 217,590
Weighted average shares outstanding-fully diluted	30,645	28,213	28,310

OPERATIONAL HIGHLIGHTS

	2001	2000	1999
Average daily production (MMcfe/d)	246	218	195
Total production (Bcfe)	89.8	79.7	71.2
Net proved reserves (Bcfe)	608	562	541
Average realized gas price per Mcf	$ 4.24	$ 3.37	$ 2.10
Capital expenditures	$ 368,277	$ 184,512	$ 147,943

[1] The Company defines "Discretionary Cash Flow" as the sum of Net Income, Deferred Taxes, Depreciation, Depletion and Amortization less Capitalized Interest.

[2] For 1999, includes the aforementioned plus Interest Expense, net of tax, and Capitalized Interest that would have been fore gone given the assumed conversion of $80 million in outstanding borrowing to KeySpan.

At year-end 2001, we acquired strategic producing properties in our South Texas core area. The $69 million acquisition of approximately 25,000 gross acres effectively doubles the Company's acreage position in this area, increases our onshore reserve base by 85 Bcfe, or 30%, and provides substantial low-risk drilling opportunities, all without adding general and administrative expense. As a result of this acquisition, onshore assets now account for approximately two-thirds of the Company's reserves and half of our annual production.

In the offshore division, the Company has concentrated operations in key areas on the Gulf of Mexico shelf where there is considerable existing infrastructure, providing efficiencies that optimize operating and cash margins. During 2001, Houston Exploration drilled 20 wells, 14 of which were successful, achieving a 70% success rate. As a result of our efforts to increase production and bring 4 new fields on line, the offshore division increased production 30% to an average of 129 MMcfe/d compared to 2000. At year-end, the Company maintained a substantial lease position with a total of 101 lease blocks in the shallow waters of the Gulf of Mexico, 59 of which were undeveloped with substantial exploratory potential.

With our operating divisions in place..., we are poised to benefit from market conditions in 2002.

During the year, the Company significantly increased our 3-D seismic data. We now have regional data that covers most of our South Texas properties. We also acquired 3-D seismic over much of the undrilled potential in our existing inventory, including three deep shelf exploration prospects. The data allows us to more accurately evaluate our leasehold, lease sales, farm-outs and acquisitions. More importantly, the data provides enhanced exploration risk assessment in advance of the drill bit.

Having made operational, financial, organizational and strategic progress in 2001, Houston Exploration is attractively positioned for the 2002 gas price environment. We have a well-balanced drilling portfolio, 3-D data to improve our evaluation of drilling risk and a high working interest position that allows us to maintain capital flexibility. Our balance of low-risk development drilling onshore combined with higher impact drilling offshore prepares us to grow our reserve base and increase production in 2002 and beyond.

Additionally, our onshore and offshore operating divisions are supported by a 2002 capital budget of $250 million. In anticipation of the present lower gas price cycle, we hedged approximately 64% of our 2002 production with floor prices averaging $3.40 per MMBtu, which protects our cash flow in the current price environment. With predictable cash flow we will continue to build our inventory and drill prospects both onshore and offshore.

We also have the financial and organizational resources to take advantage of acquisition opportunities that will arise as a result of current gas prices. Our new acquisition function will aggressively seek to acquire properties at attractive prices. With our operating divisions in place to integrate new assets, we are poised to benefit from market conditions in 2002.

As we move forward, we would like to recognize the employees of Houston Exploration for their contributions to the Company last year. We appreciate their motivation and outstanding performance during 2001, a year of organizational transitions and record operating activity, which provided outstanding financial results. We would also like to recognize Craig G. Matthews, who has elected to retire from our Board of Directors. His sound business counsel and dedication to Houston Exploration served our Company and our shareholders well, and he leaves with our deepest gratitude and respect. Finally, we would like to thank our directors for their support of The Houston Exploration Company. We are confident that our progress in 2002 will earn the continued support and confidence of our shareholders.

Sincerely,

Robert B. Catell

Robert B. Catell
Chairman of the Board of Directors

W G Hargett

William G. Hargett
President and Chief Executive Officer

March 25, 2002

Dear Shareholder:

Houston Exploration is pleased to report record operational and financial results for the second consecutive year. We increased our drilling activity, production, reserves, net income and cash flow. We welcomed new leadership, sharpened our operational focus through a corporate realignment and substantially enhanced our technological capabilities. We added significant onshore acreage to our portfolio, complementing the contribution of our offshore operations. We are pleased to share with you these and other highlights of this successful year, as well as the strategy and programs that made it possible, and to introduce our plans for 2002.

Houston Exploration's achievements in 2001 demonstrate the effectiveness of our strategy, which incorporates the natural gas price cycle. While we are optimistic about the long-term prospects for natural gas based on its value to the economy and the environment, we recognize that gas prices are highly cyclical, so we manage our asset base and capital programs in confluence with the price cycle. When gas prices are high, we prefer to drill our ample inventory of prospects, monetize our reserves, strengthen the balance sheet and strategically hedge gas forward to prepare for the next pricing cycle. The hedges provide predictable cash flow during low gas price periods, when we prefer to balance drilling with acquisitions, farm-ins and leasing, all typically available at lower costs.

Our asset base lends itself well to this strategy. The vast majority of our assets, about 93%, are natural gas producing properties concentrated in a few core operating areas. We operate approximately 85% of our properties and plan to retain a high working interest in our wells. As a result, our talent and activities are tightly focused, we have more control of the drilling schedule, and we are able to maintain our low cost structure. This gives us flexibility to manage our business quickly and effectively, enhancing shareholder value throughout the price cycle.

Our impressive results in 2001 are a result of capturing value throughout the natural gas price cycle. Taking advantage of high gas prices early in the year, we invested a significant portion of our capital in low-risk projects from our inventory designed to generate immediate production. We achieved the highest level of drilling activity in the Company's history, drilling nearly 100 wells. Production in 2001 increased 13% to 90 Bcfe with an exit rate at year-end of 263 MMcfe/d, compared to record production of 80 Bcfe and an exit rate of 256 MMcfe/d at year-end 2000.

Our capital spending was fueled by the second consecutive year of record cash flow, even though natural gas prices dropped dramatically from $9.75 per Mcf at year-end 2000 to $2.55 per Mcf at year-end 2001. We protected the Company's cash flow from this decline with our risk management program using hedges and were able to moderate the cyclical nature of energy prices. Houston Exploration's realized gas price in 2001 was $4.24 per Mcf, 26% higher than the prior year's realized gas price of $3.37 per Mcf.

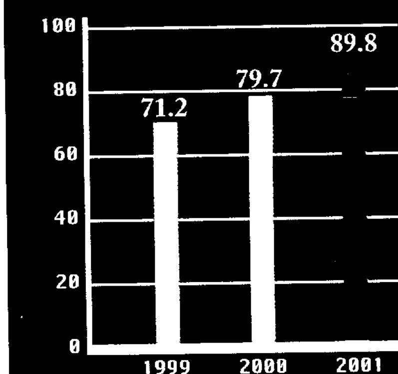
We achieved the highest level of drilling activity in the Company's history, drilling nearly 100 wells.

Our strong gas price realizations, combined with higher production levels, generated 2001 cash flow totaling $313 million, a 53% increase over 2000 cash flow of $204 million. Net income for 2001 totaled nearly $123 million and marked a 44% increase over 2000 net income of $85 million. As a result, Houston Exploration was able to strengthen our balance sheet and create greater financial flexibility to grow organically as well as through acquisitions.

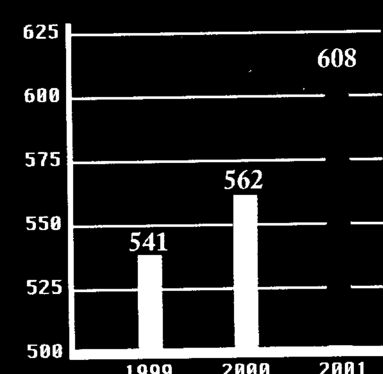
Organizationally, Houston Exploration experienced a transition in leadership in 2001. We also realigned our operations by creating separate onshore and offshore operating divisions. This new corporate structure allows each business unit to focus on its own distinctive asset base, capital requirements and growth opportunities. We are pleased to report that each division increased drilling activity over the prior year, resulting in an overall 78% drilling success rate in 2001. In addition, we created a separate acquisition function to support each business unit's organic growth.

DISCRETIONARY CASH FLOW
Millions of Dollars

PRODUCTION
Bcfe



NET PROVED RESERVES
Bcfe



- Houston Exploration has strategically focused on the following select core operating areas:

OFFSHORE

Gulf of Mexico Shelf

ONSHORE

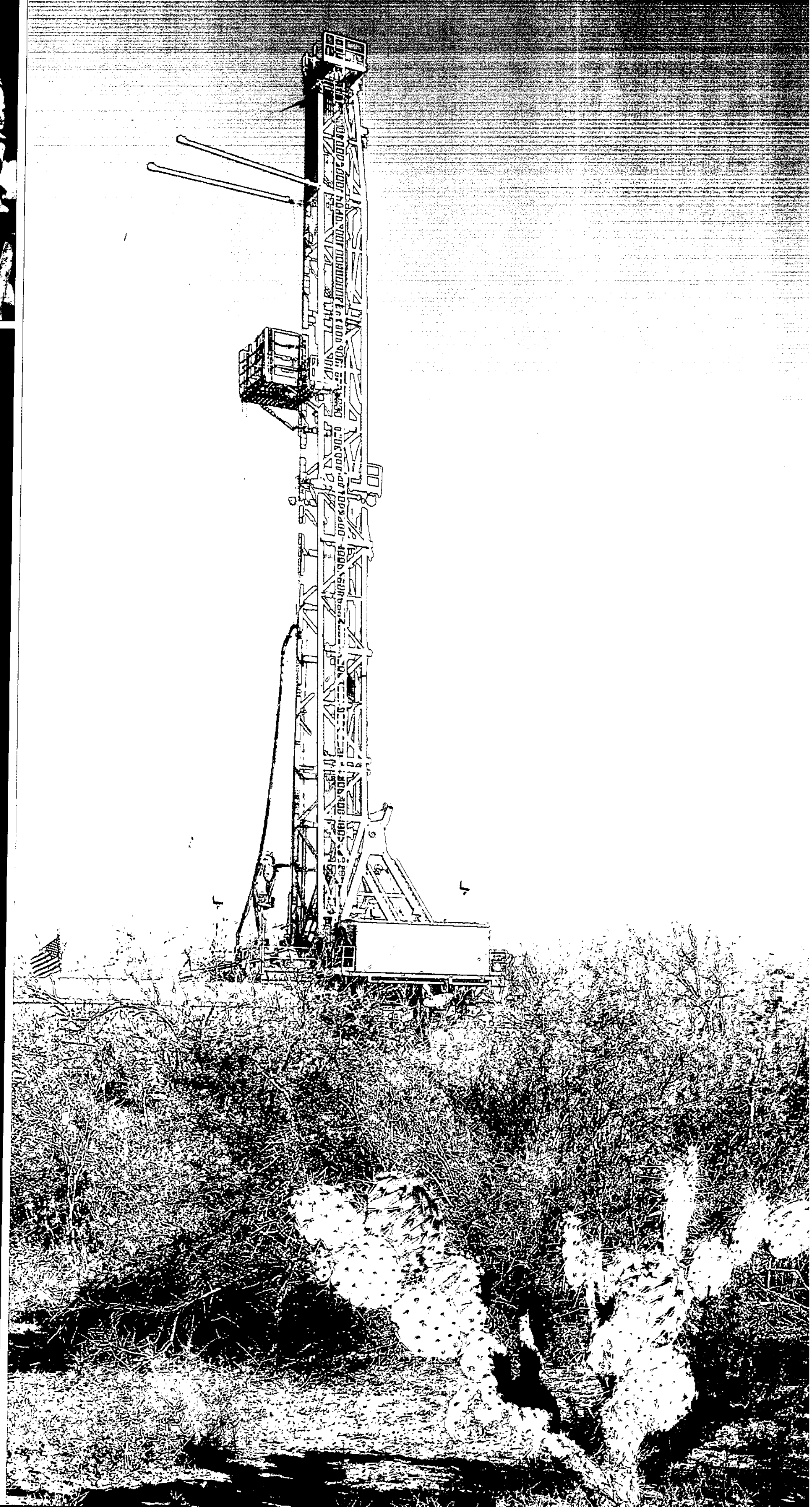
South Texas

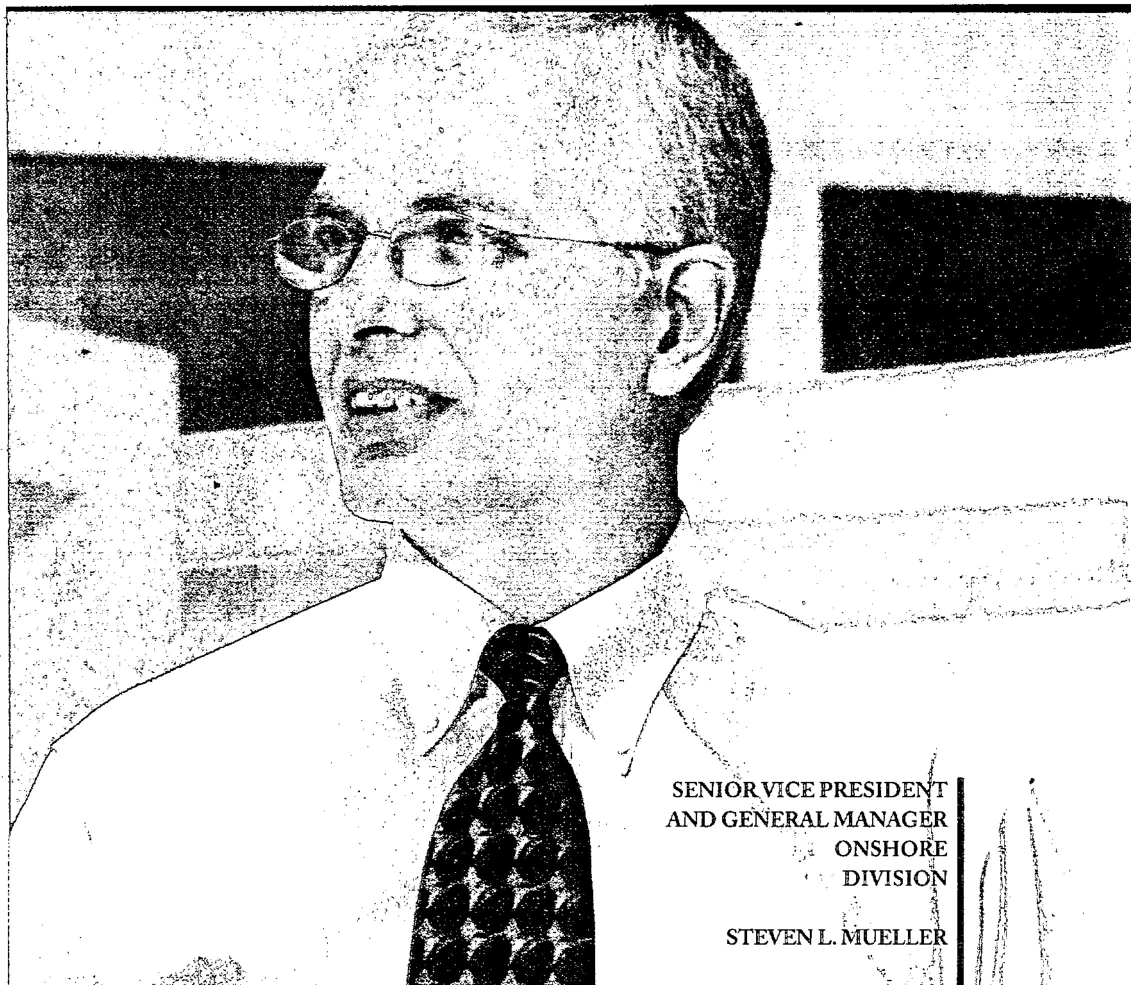
Arkoma Basin

East Texas

South Louisiana

West Virginia





SENIOR VICE PRESIDENT
AND GENERAL MANAGER
ONSHORE
DIVISION

STEVEN L. MUELLER

onshore operating division

ONSHORE
OPERATIONS
MANAGER

JOANNE HRESKO

Onshore
Team Players

In 2001, Houston Exploration realigned the Company's operating structure and formed two operating divisions, onshore and offshore, allowing each to concentrate on its distinctive production and reserve base.

The onshore asset base of Houston Exploration includes 95% of the Company's active wells and accounts for approximately two-thirds of the Company's reserves and approximately half of its annual production. The Company operates approximately 85% of its properties. The onshore activities provide for a stable and predictable platform for growth. Most of the actual 2001 and the planned 2002 activity are concentrated in two areas – Webb and Zapata Counties in South Texas and the Arkoma Basin.

Our primary onshore area of focus has been in South Texas. Acquired in 1996, the Charco Field has delivered production growth from an average net rate of approximately 38 MMcfe/d in 1996 to an average net rate of approximately 83 MMcfe/d in 2001.

Since 1996, the Company has added reserves of 182 Bcfe, while producing 145 Bcfe. In 2001, Houston Exploration utilized a three-rig program and successfully completed 29 of 36 wells, representing an 80% success rate. The Company plans to continue with a similar drilling program through 2002.

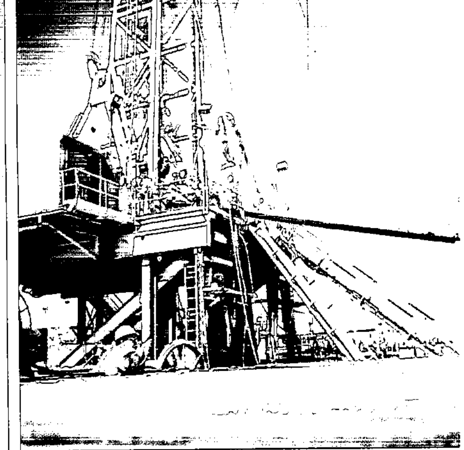
At year-end 2001, Houston Exploration made a significant addition to its South Texas core area when it acquired 85 Bcfe in reserves for $69 million. South Texas reserves increased by 50% and the 2002 net production is projected to increase 20%. Adding approximately 25,000 gross acres nearly doubled the Company's acreage position in the area. This acreage provides a four-year inventory of locations assuming one rig drilling continuously in 2002. Because of its close proximity to existing operations at Charco, this acquisition of producing properties added no additional general and administrative expense to the Company's ongoing operations.

Much of the Company's past success in South Texas can be attributed to detailed 3-D seismic imaging of the Charco Field. To build on that success, Houston Exploration acquired 1,200 square miles of 3-D seismic data in Webb and Zapata counties in 2001. This investment helped the division in the analysis of its 2001 acquisition and is expected to further enhance the Company's drilling success rate and provide additional drilling opportunities in the future.

The Company's second core area is the Arkoma Basin. Houston Exploration drilled 31 successful wells in 2001 with an 89% success rate. This region has consistently provided the Company with low finding and development costs and continues to provide many years of drilling inventory.

At year-end, the Company had identified approximately 100 additional drilling locations in the Arkoma Basin with the present spacing, providing a 3 to 4 year inventory. The Company plans approximately 30 wells in 2002 and because of the geologic complexities, believes our fields will require closer spacing of wells in the future. Regulatory approval of the tighter spacing will be requested in 2002 and upon approval, could more than double the future locations.

Both South Texas and the Arkoma Basin will be important for Houston Exploration for many years. The Company has the organizational focus, the people and the data to continue unlocking the potential of these areas. An additional goal in 2002 is to develop a third onshore focus. The Company is actively pursuing acquisitions and exploration opportunities that can replicate its past onshore accomplishments.

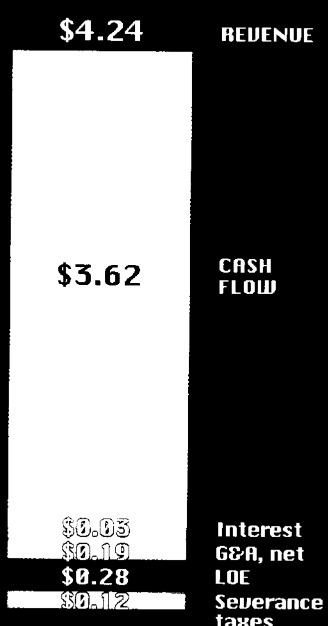


NET PROVED RESERVES
12/31/01

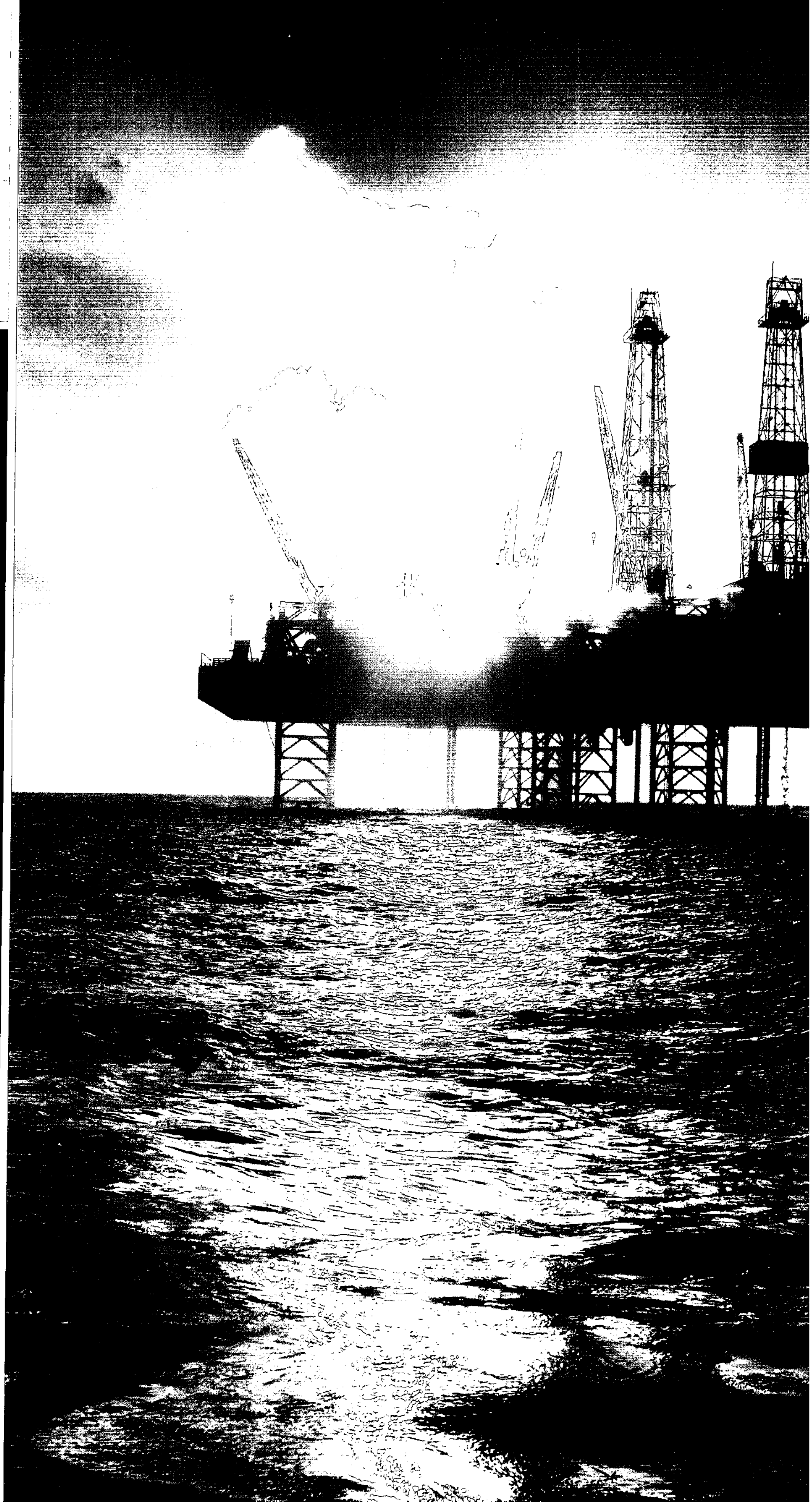
608 BCFE

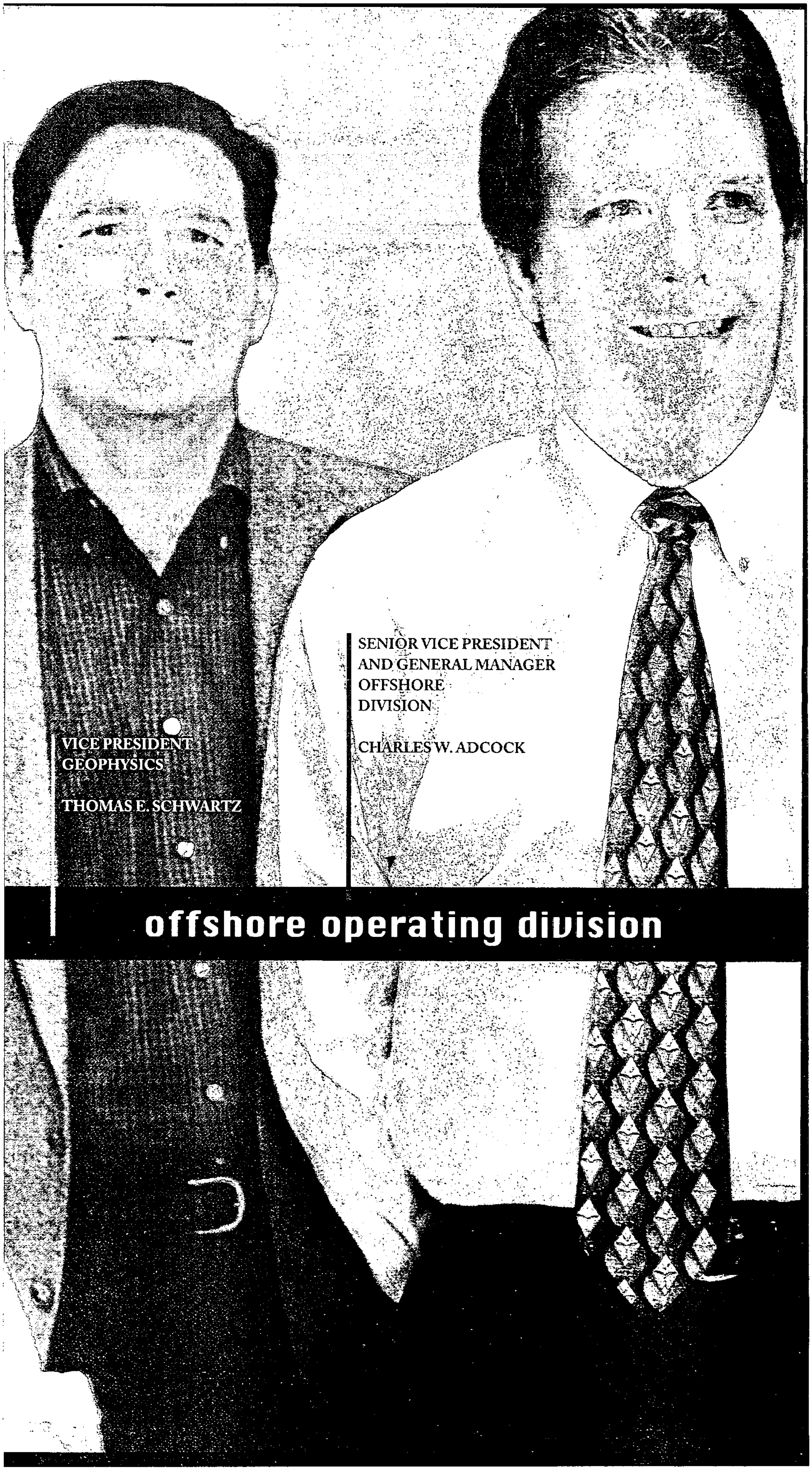
- At year-end 2001 — with the acquisition of producing properties in South Texas — Houston Exploration's reserve base is approximately 60% onshore and 40% offshore.
- Houston Exploration has achieved compounded annual reserve growth of approximately 13% since January 1, 1997.
- In 2001, Houston Exploration drilled a total of 76 wells onshore with an 80% success rate.

2001
OPERATING MARGINS
($/Mcfe)



- Houston Exploration has consistently had one of the lowest operating cost structures in the industry. The Company continues its efforts to maintain or reduce operating costs resulting in consistently high cash margins.




VICE PRESIDENT
GEOPHYSICS
THOMAS E. SCHWARTZ
SENIOR VICE PRESIDENT
AND GENERAL MANAGER
OFFSHORE
DIVISION
CHARLES W. ADCOCK
offshore operating division

Offshore

Team Players

In the offshore division, Houston Exploration drilled 20 wells, 14 of which were successful, achieving a 70% success rate. The Company focused its efforts on increasing production during the year and for the full year offshore production averaged 129 MMcfe/d, a 30% increase over 2000. The production increase in 2001 was realized while maintaining operating costs at the same level as 2000 and resulted in a 24% decrease in operating costs on an Mcfe basis.

During 2001, the offshore division completed several development projects and, in particular, the development of two oil fields discovered in 2000. Houston Exploration completed the installation of a platform and related facilities at Vermilion 408. An additional development well was drilled and production from this field began early in 2002. Gross rates from this field are expected to peak at 15-20 MMcf/d and 6,000 BOPD. The division has budgeted for additional exploratory work in this field during 2002.

The Company is also currently designing a platform and facilities for South Timbalier 314/317. This platform will be installed in the fourth quarter of 2002 and will establish both development and exploratory drilling opportunities for our 2003 drilling program. Production from the two existing wells is anticipated by year-end 2002.

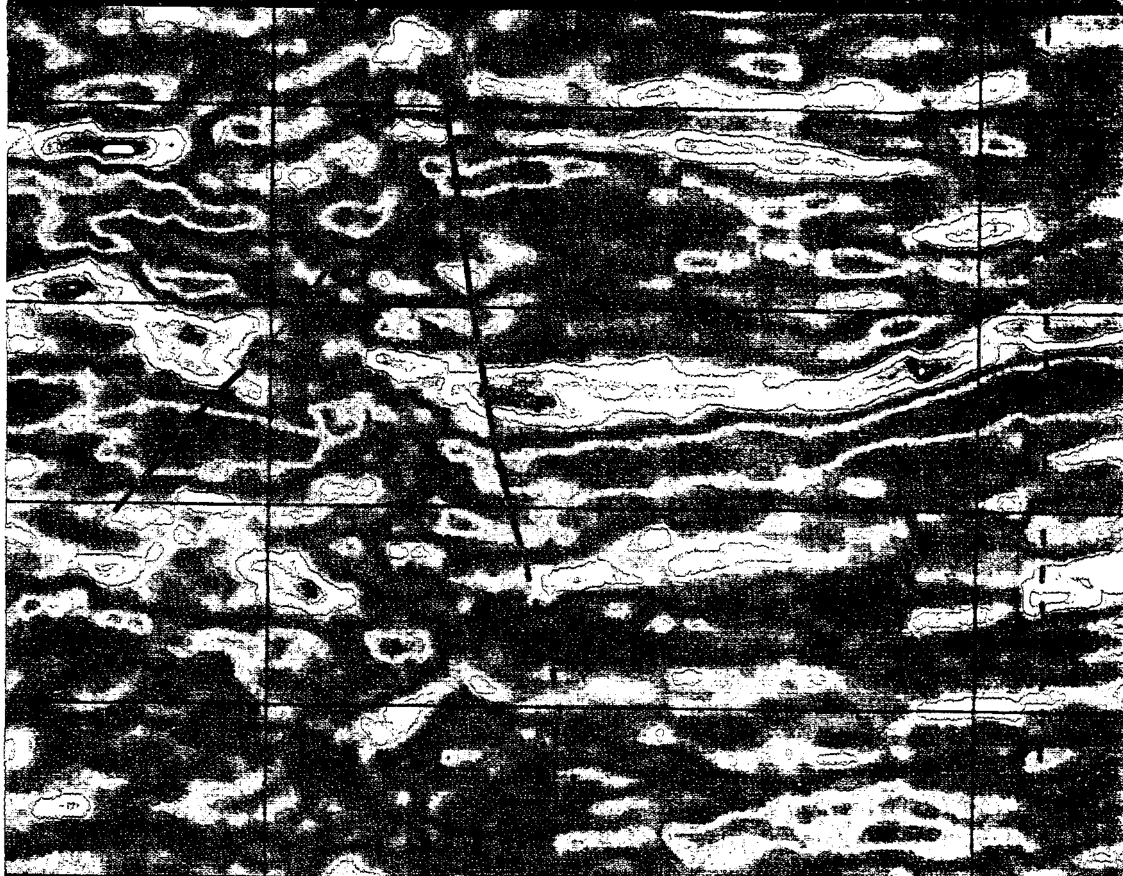
To maintain a competitive advantage in the Gulf of Mexico, the exploration group reviewed and addressed crucial and fundamental issues involving hardware and software technology and data warehousing. The results of this review included the addition of new seismic data to improve understanding of the risks of present prospects, more efficient handling of data to improve prospect generation and a renewed emphasis in optimizing our exploration portfolio.

The Company added 400 blocks of data to its in-house inventory in 2001. This data will be used to further evaluate the Company's exiting leasehold as well as acquisition and farm-in opportunities. At year-end, the Company held a total of 101 lease blocks in the shallow waters of the Gulf of Mexico, of which 59 are undeveloped.

Entering into 2002 the Company plans to use its extensive lease position offshore as leverage to improve return on capital and reduce risk exposure. With the addition of the new 3-D data the Company will actively participate in upcoming lease sales as well as pursue industry farm-ins to expand its drilling inventory for 2003 and beyond. To balance the exploration program the offshore division also plans a more proactive approach towards acquisitions. Finally we will continue to optimize operating efficiencies where possible to maintain our position as a low cost operator allowing the company to effectively operate in the low portion of the price cycle.

Technology

Advances & Investments



Seismic courtesy of DIAMOND–PGS Geophysical Service Corporation

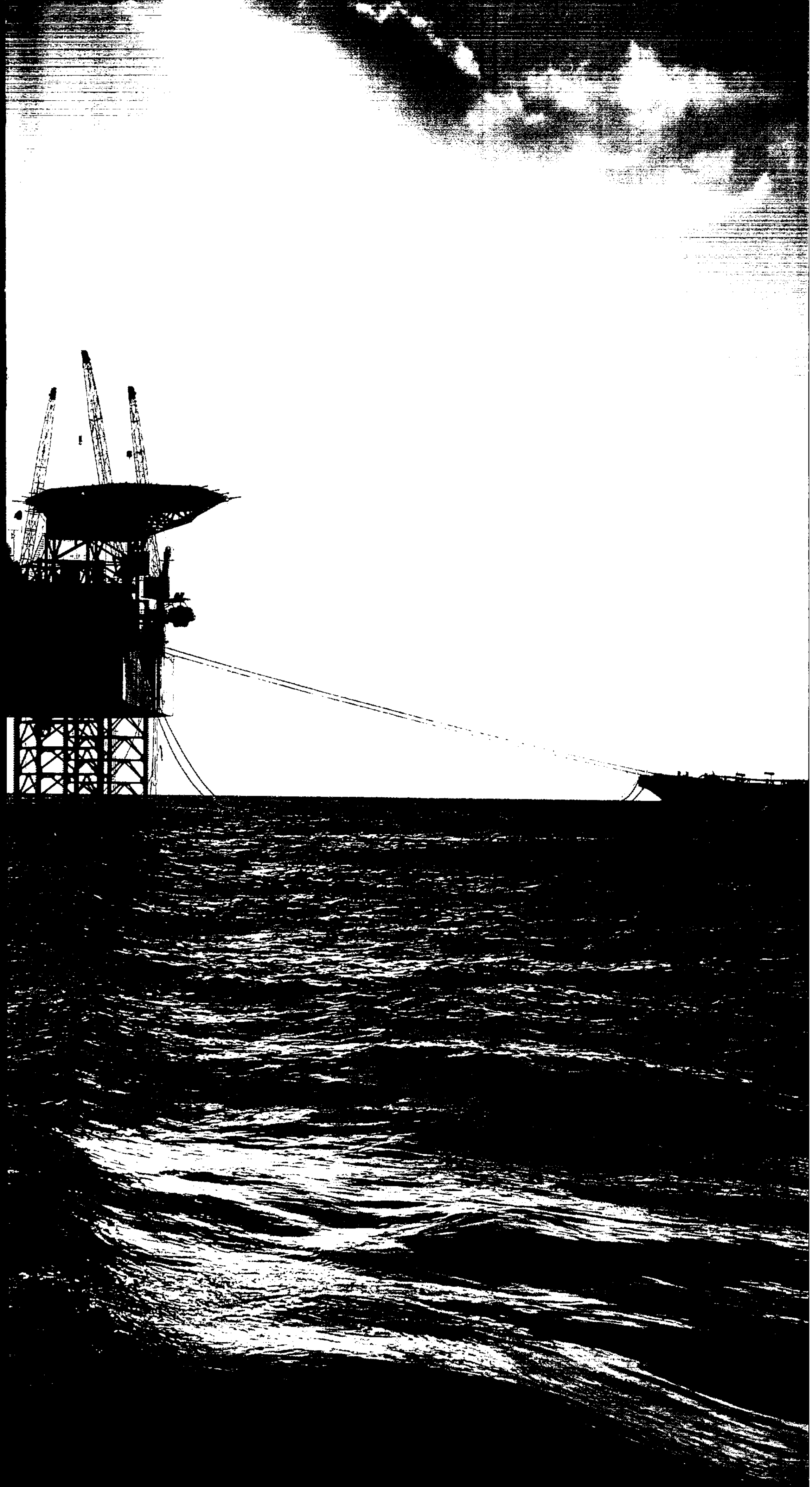
Houston Exploration invested to enhance its technological capabilities for its onshore and offshore operations in 2001. The Company increased its 3-D seismic database by licensing large blocks of high quality 3-D data within core areas of the Gulf of Mexico shelf and South Texas. Additionally, the Company invested in technical systems and software upgrades to improve its risk assessment capabilities.

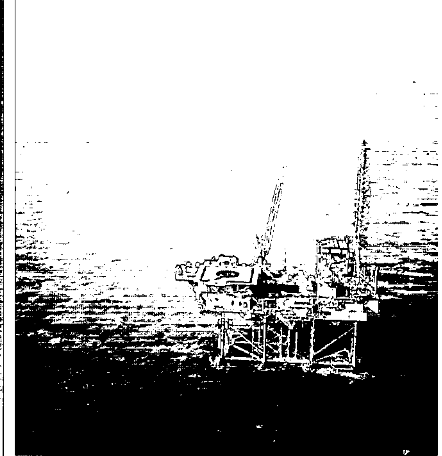
In South Texas, the regional 3-D data has already strengthened analyses at the individual well, the field and the acquisition levels. It enabled the Company to accelerate the 2002 drilling program on its recent acquisition, identified new prospects that will be drilled later in 2002 and delineated future leasing and farmout candidates the Company is pursuing.

Offshore, the 3-D has provided a new view of the Company's current producing properties, detecting new drilling opportunities both on the Company's acreage and along trend. It is being used to confirm the present prospect inventory and is vital for correctly evaluating acreage at lease sales this year and in the future.

The Company's investment in new systems allows each interpreter to be more productive. These new efficiencies will result in better opportunities that are developed faster while maintaining the Company's low cost structure.

With improved prospect risk assessment, the Company will evaluate the appropriate level of capital exposure on each exploratory prospect and incorporate the results into our drilling program for 2002 and beyond. All of these measures are expected to have an immediate and sustainable impact on finding and development costs.





- Houston Exploration's operating divisions provide a strong production balance — with year-end 2001 results reflecting the Company's average daily rate below:

AVERAGE DAILY
PRODUCTION, NET
12/31/01

246 Mmcfe/d

- Houston Exploration has achieved compounded annual production growth of approximately 23% since January 1, 1997.

- The Company's total reserve replacement since January 1, 1997 has been 181%.

- In 2001, Houston Exploration drilled a total of 20 wells offshore with a 70% success rate.

BOARD OF DIRECTORS

ROBERT B. CATELL (A,C)
Chairman of the Board of Directors

WILLIAM G. HARGETT (A)

GORDON F. AHALT (A,B,C,D)

DAVID G. ELKINS

RUSSELL D. GORDY (B)

GERALD LUTERMAN

CRAIG G. MATTHEWS

H. NEIL NICHOLS

JAMES Q. RIORDAN (B,C)

DONALD C. VAUGHN (D)

(A) Member, Executive Committee
(B) Member, Audit Committee
(C) Member, Compensation Committee
(D) Member, Nominating Committee

(Seated, Left to Right) **GORDON F. AHALT, ROBERT B. CATELL, DAVID G. ELKINS, H. NEIL NICHOLS**
(Standing, Left to Right) **GERALD LUTERMAN, CRAIG G. MATTHEWS, JAMES Q. RIORDAN, WILLIAM G. HARGETT, DONALD C. VAUGHN,** (*not pictured,* **RUSSELL D. GORDY**)

EXECUTIVE OFFICERS

WILLIAM G. HARGETT
President & Chief Executive Officer

CHARLES W. ADCOCK
Senior Vice President
& General Manager
Offshore Division

STEVEN L. MUELLER
Senior Vice President
& General Manager
Onshore Division

TRACY PRICE
Senior Vice President – Land

JAMES F. WESTMORELAND
Vice President,
Chief Accounting Officer
& Corporate Secretary

THOMAS E. SCHWARTZ
Vice President – Geophysics

(Left to Right) **WILLIAM G. HARGETT, STEVEN L. MUELLER, THOMAS E. SCHWARTZ, JAMES F. WESTMORELAND, TRACY PRICE, CHARLES W. ADCOCK**

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, 2001
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File No. 001-11899

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

Delaware (State or other jurisdiction of Incorporation or organization)	22-2674487 (IRS Employer Identification No.)
1100 Louisiana, Suite 2000 Houston, Texas (Address of principal executive Offices)	77002-5215 (Zip code)

(713) 830-6800
(Registrant's telephone number, including area code)

Securities Registered Pursuant To Section 12(b) of The Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $.01 par value	New York Stock Exchange
$8^5/_8$% Senior Subordinated Notes due 2008	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 Regulations 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 ✓

The aggregate market value of the voting stock held by non-affiliates of the registrant was approximately $313,317,825 of March 13, 2002, based on the closing sales price of the registrant's common stock on the New York Stock Exchange on such date of $30.99 per share. For purposes of the preceding sentence only, all directors, executive officers and beneficial owners of ten percent or more of the common stock are assumed to be affiliates. As of March 13, 2002, 30,490,680 shares of common stock were outstanding.

INCORPORATION OF DOCUMENTS BY REFERENCE

Portions of The Houston Exploration Company's definitive proxy statement relating to the registrant's 2002 annual meeting of stockholders, which proxy statement will be filed under the Securities Exchange Act of 1934 within 120 days of the end of the registrant's fiscal year ended December 31, 2001, are incorporated by reference into Part III of this Form 10-K.

All of the estimates and assumptions contained in this Annual Report and in the documents we have incorporated by reference into this Annual Report constitute forward looking statements as that term is defined in Section 27A of the Securities Act of 1993 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements generally are accompanied by words such as "anticipate," "believe," "expect," "estimate," "project" or similar expressions. All statements under the caption "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" relating to our anticipated capital expenditures, future cash flows and borrowings, pursuit of potential future acquisition opportunities and sources of funding for exploration and development are forward looking statements. Although we believe that these forward-looking statements are based on reasonable assumptions, our expectations may not occur and we cannot guarantee that the anticipated future results will be achieved. A number of factors could cause our actual future results to differ materially from the anticipated future results expressed in this Annual Report. These factors include, among other things, the volatility of natural gas and oil prices, the requirement to take write downs if natural gas and oil prices decline, our ability to meet our substantial capital requirements, our substantial outstanding indebtedness, the uncertainty of estimates of natural gas and oil reserves and production rates, our ability to replace reserves, and our hedging activities. For additional discussion of these risks, uncertainties and assumptions, see "Items 1 and 2. Business and Properties" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in this Annual Report.

In this Annual Report, unless the context requires otherwise, when we refer to "we", "us" or "our", we are describing The Houston Exploration Company and its subsidiaries on a consolidated basis. Further, if you are not familiar with the oil and gas terms used in this report please refer to the explanations of the terms under the caption "Glossary of Oil and Gas Terms" included on pages G-1 through G-3. When we refer to "equivalents," we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one barrel of oil is equal to six thousand cubic feet of natural gas.

Part I.

Items 1 and 2. *Business and Properties*

Overview

We are an independent natural gas and oil company engaged in the exploration, development, exploitation and acquisition of domestic natural gas and oil properties. Our offshore properties are located primarily in the shallow waters of the Gulf of Mexico, and our onshore properties are located in South Texas, the Arkoma Basin of Oklahoma and Arkansas, South Louisiana, the Appalachian Basin in West Virginia and East Texas.

At December 31, 2001, our net proved reserves were 608 billion cubic feet equivalent, or Bcfe, with a discounted present value of cash flows before income taxes of $714 million. Our focus is natural gas and approximately 93% of our net proved reserves at December 31, 2001 were natural gas and approximately 74% of our net proved reserves were classified as proved developed. We operate approximately 85% of our properties.

We began exploring for natural gas and oil in December 1985 on behalf of The Brooklyn Union Gas Company. Brooklyn Union is an indirect wholly owned subsidiary of KeySpan Corporation. KeySpan, a member of the Standard & Poor's 500 Index, is a diversified energy provider whose principal natural gas distribution and electric generation operations are located in the Northeastern United States. In September 1996 we completed our initial public offering. As of December 31, 2001, THEC Holdings Corp., an indirect wholly owned subsidiary of KeySpan, owned approximately 67% of the outstanding shares of our common stock.

Our principal executive offices are located at 1100 Louisiana, Suite 2000, Houston, Texas 77002 and our telephone number is (713) 830-6800.

Business Strategy

Our strategy is to use our technical expertise to grow our reserves, production and cash flow through the application of a three-pronged approach that combines:

- high potential offshore exploration and exploitation;
- lower risk, high impact exploitation and development drilling onshore; and
- selective opportunistic acquisitions both offshore and onshore.

We believe that the lower risk projects and more stable production typically associated with our onshore properties complement our high potential exploratory prospects in the Gulf of Mexico by balancing risk and reducing volatility.

From January 1, 1997 through December 31, 2001, we increased our proved reserve base at a compound annual growth rate of 13% and increased our annual production at a compound annual growth rate of 23%. During the past five years, we produced a total of 355 Bcfe and added 641 Bcfe of net proved reserves. Of the total reserves added, we added 376 Bcfe through exploration and development and 265 Bcfe through acquisitions. In total, we replaced 181% of production through drilling and acquisitions, with 106% replaced through the drillbit alone. During December 2001, our daily production averaged 259 million cubic feet equivalent, or MMcfe, per day.

We focus on the following elements in implementing our strategy:

High Potential Exploratory and Development Drilling in the Gulf of Mexico

We hold interests in 101 lease blocks, representing 496,955 gross (391,737 net) acres, in federal and state waters in the Gulf of Mexico, of which 59 blocks are undeveloped. We believe we have assembled a four-year inventory of offshore prospects. We plan to drill approximately eight exploratory wells in the Gulf of Mexico during 2002. Over the past five years, we have drilled 29 successful exploratory wells and 23 successful development wells in the Gulf of Mexico, representing a historical success rate of 70%. Of our $250 million 2002 capital expenditure budget, we anticipate that approximately $96 million, which excludes capitalized interest, capitalized general and administrative costs and property acquisitions costs, will be spent on offshore projects. In addition, we intend to continue our participation in federal lease sales and to actively pursue attractive farm-in opportunities as they become available. Our management believes that the Gulf of Mexico remains attractive for future exploration and development activities due to the availability of geologic data, remaining reserve potential and the infrastructure of gathering systems, pipelines, platforms and providers of drilling services and equipment. Offshore properties account for approximately 40% of our net proved reserves As of December 31, 2001. Our average daily production during December 2001 was 147 MMcfe per day, net to our interests.

Lower Risk, High Impact Exploitation and Development Drilling Onshore

We own significant onshore natural gas and oil properties in the following areas:

- the Lobo trend in South Texas,
- the Arkoma Basin of Oklahoma and Arkansas,
- the South Lake Arthur and Lake Pagie Fields in South Louisiana,
- the Appalachian Basin in West Virginia, and
- East Texas.

These properties favor exploitation and development drilling. Our onshore properties account for approximately 60% of our net proved reserves at December 31, 2001. Complementing the offshore properties, our onshore properties are typically characterized by relatively longer reserve lives, more predictable production streams and lower operating cost structures. Over the past five years, we have drilled or participated in the drilling of 191 successful development wells and seven successful exploratory wells onshore, together representing a historical drilling success rate of 84%. We have identified an extensive inventory of more than 200 potential onshore drilling locations, of which approximately 125 are located in South Texas. Of our $250 million 2002 capital expenditure budget, we anticipate that approximately $128 million, which excludes capitalized interest, capitalized general and administrative costs and property acquisition costs, will be spent on onshore projects, including the drilling of approximately 86 wells. Production from our onshore properties averaged 112 MMcfe per day, net to our interests, during December 2001.

Opportunistic Acquisitions

Our primary strategy to grow our reserves through the drillbit is supplemented by our continuing pursuit of opportunistic acquisitions of properties with unexploited reserve potential. We believe we have a successful track record of building our reserves through acquisitions onshore and in the Gulf of Mexico and successfully exploiting the reserves acquired. We target properties that:

- we can operate;
- are either in the Gulf of Mexico or onshore in our existing operating areas or in new geographic areas in which we believe we can establish a substantial concentration of properties and operations; and
- provide a base for further exploration and development.

Use of Advanced Technology for In-House Prospect Generation

We generate virtually all of our exploration prospects through our in-house geological and geophysical expertise. We use advanced technology, including 3-D seismic and in-house computer-aided exploration technology, to reduce risks, lower costs and prioritize drilling prospects. We have assembled a library of 3-D seismic data, covering approximately 98% of our undeveloped offshore lease blocks and other possible lease and acquisition prospects in the Gulf of Mexico. Onshore, our library of seismic data covers approximately 1,330 square miles of our South Texas acreage and surrounding areas and approximately 100 square miles in South Louisiana. We employ 11 geologists and geophysicists with a combined industry experience averaging over 20 years. We use 14 geophysical workstations for interpretation of 3-D seismic data. The availability of 3-D seismic data at reasonable costs has improved our ability to identify exploration and development prospects in our existing inventory of properties and to define possible lease and acquisition prospects.

High Percentage of Operated Properties

Acquiring operating positions is a key component of our strategy. Currently, we operate approximately 85% of our properties, which accounted for approximately 80% of our production during 2001. We prefer to operate our properties in order to manage production performance while controlling operating expenses and the timing and amount of capital expenditures. We also pursue cost savings through the use of outside contractors for a portion of our offshore field operations activities. During 2001, we realigned our internal operations into two distinctive operating divisions, offshore and onshore, so that we could effectively manage specific projects and growth strategies for each area. As a result of these operating strategies combined with our close monitoring of costs and expenses, we achieved lease operating expense (excluding severance taxes of $0.12 per thousand cubic feet equivalent, or Mcfe) of $0.28 per Mcfe of production and net general and administrative expense of $0.19 per Mcfe of production for the year ended December 31, 2001.

Geographically Concentrated Operations

We currently operate in six areas of geographic concentration: the Gulf of Mexico, South Texas, the Arkoma Basin, South Louisiana, West Virginia and East Texas. We continue to evaluate additional areas with the goal of adding them in the future. By concentrating our operations into geographically focused areas, we are able to manage a large asset base with a relatively small number of employees and to add and operate production at relatively low incremental costs. Our strategy of focusing drilling activities on properties in relatively concentrated offshore and onshore areas permits us to more efficiently utilize our base of geological, engineering, exploration and production experience in these regions.

Recent Acquisition

Conoco Acquisition. On December 31, 2001, we completed the purchase of natural gas and oil properties and associated gathering pipelines and equipment, together with developed and undeveloped acreage, located in Webb and Zapata counties of South Texas, from Conoco Inc. The $69 million purchase price was paid in cash and financed by borrowings under our revolving bank credit facility. The properties purchased cover approximately 25,274 gross (16,885 net) acres located in the Alexander, Haynes, Hubbard and South Trevino Fields, which are in close proximity to our existing operations in the Charco Field, and represent interests in approximately 159 producing wells. We operate approximately 95% of the producing wells we acquired and our average working interest is 87%. With this acquisition, we have expanded and expect to improve our operations in South Texas which have been an area of strategic growth for us over the last five years. During February 2002, the properties we acquired produced approximately 19.0 MMcfe per day, net to our interests.

Keyspan Joint Venture

Effective January 1, 1999, we entered into a joint exploration agreement with KeySpan Exploration & Production, LLC, a subsidiary of our majority stockholder, KeySpan, to explore for natural gas and oil over an initial two-year term expiring on December 31, 2000. Under the terms of the joint venture, we contributed all of our then undeveloped offshore acreage to the joint venture and KeySpan was entitled to receive 45% of our working interest in all prospects drilled under the program. KeySpan paid 100% of actual intangible drilling costs for the joint venture up to a specified maximum per year and all additional intangible drilling costs incurred were paid 51.75% by KeySpan and 48.25% by Houston Exploration. Revenues are shared 55% Houston Exploration and 45% KeySpan. In addition, we received reimbursements from KeySpan for a portion of our general and administrative costs.

Effective December 31, 2000, KeySpan and Houston Exploration agreed to end the primary or exploratory term of the joint venture. As a result, KeySpan will not participate in any of our offshore exploration prospects unless the project involves the development or further exploitation of discoveries made during the initial term of the joint venture. In addition, effective with the termination of the exploratory term of the joint venture, we will not receive any reimbursement from KeySpan for general and administrative costs.

Since the beginning of our joint venture with KeySpan in January 1999, KeySpan has spent a total of $99.3 on exploration and development, with $ 17.2 million spent during 2001, $46.5 million spent during 2000 and $35.6 million spent during 1999. During the initial two-year exploratory term of the joint venture, we received from KeySpan a total of $7.3 million in general and administrative expense reimbursements, with $2.5 million paid during 2000 and $4.8 million paid during 1999. Reimbursement for general and administrative expenses terminated in 2000 with the expiration of the exploratory term of the joint venture.

During the initial two-year term of the joint drilling program, we drilled a total of 21 wells under the terms of the joint venture: 17 exploratory wells and four development wells. Five of the wells drilled were unsuccessful. During 2001, KeySpan participated in three additional wells, all of which were successful, and further developed or delineated reservoirs discovered during the initial term of the joint venture. For 2002, KeySpan has committed to a capital budget of $15 million for development projects associated with its working interests in wells drilled under the joint venture during 1999, 2000 and 2001.

Gulf of Mexico Properties

We hold interests in 101 offshore blocks, of which 33 are currently producing. We operate 24 of these producing blocks, accounting for approximately 75% of our offshore production. The following table lists our net proved reserves, average working interest and the operator for our largest offshore fields As of December 31, 2001. These properties represent over 80% of our Gulf of Mexico proved reserves and approximately 75% of our offshore production during 2001:

	Net Proved Reserves at December 31, 2001				
Offshore Fields	Gas (MMcf)	Oil (MBbls)	Total (MMcfe)	Average Working Interest	Operator
Mustang Island Blocks A-31/32	63,077	188	64,205	100%	Company
West Cameron Blocks 76/77/60/61	25,048	182	26,140	15%	Third Party
South Timbalier Blocks 314/317	4,323	3,020	22,443	55%	Company(1)
East Cameron Blocks 82/83	14,917	120	15,637	100%	Company
Mustang Island Blocks 858/868	9,743	214	11,027	83%	Company
High Island Blocks 38/39	10,737	142	11,589	100%	Company
West Cameron Block 587	10,594	—	10,594	64%	Third Party
Vermilion Block 408	2,316	1,102	8,928	31%	Company(1)
East Cameron Blocks 81/84	4,885	129	5,659	14%	Third Party
Matagorda Island Blocks 651/671/672	5,595	2	5,607	67%	Company
North Padre Island Block 883	4,859	116	5,555	17%	Third Party
All Other Gulf of Mexico (13 fields)	30,657	807	5,499		
Total Gulf of Mexico	186,751	6,022	222,883		

(1) Facility construction in progress at December 31, 2001.

Offshore Drilling and Development. During 2001, we drilled fourteen successful offshore wells: seven exploratory wells and seven development wells. Unsuccessful wells totaled six: five exploratory wells and one development well. Under the terms of our joint venture agreement with KeySpan, KeySpan opted to participate in three wells during the year, all of which were prospects designed to extend or further delineate prior discoveries. These projects consisted of a fourth development well at North Padre Island 883, a second exploratory well at South Timbalier 314/317 and a second exploratory well at East Cameron 81/84, all of which were successful. In addition to these KeySpan joint venture projects, we had exploratory success at East Cameron 83, South Marsh Island 253, Galveston Island 241, High Island 39 and Matagorda Island 682. Development projects during 2001 included the drilling of four development wells at our Mustang A-31/32 Field, one well at Galveston 252 and one well at the West Cameron 76/77 Field.

For 2002, we plan to drill approximately eight offshore exploratory wells and approximately two to three development wells. At December 31, 2001, we had one offshore well in progress: our third development well at Vermilion 408. The well was successfully completed, tied-in and put on-line in early February 2002. Facilities and pipelines were completed at Vermilion 408 during December 2001 and initial production from the two wells drilled during 2000 began in early January 2002. Production from all three wells is currently averaging 10.5 MMcfe/day, net to our interest. KeySpan has an interest in all three of these wells. We are currently drilling a fourth well at this location. This well is exploratory and will test a new fault block to the southwest of our current discoveries.

Other offshore wells currently in progress include two wells at East Cameron 81/84, both of which are exploratory and are being drilled by third parties. KeySpan is participating in both of these wells because the prospects could possibly extend previously discovered reservoirs. Facility installation and hook-up of East Cameron 81 #13 is currently in progress and initial production is expected by the end of March 2002. East Cameron 81 #13 was an exploratory well drilled by a third party during 2001 and was the second well drilled at this location. The first well, East Cameron 84 #1, was drilled and completed by a third party during 1999 and is currently producing. KeySpan also has an interest in both East Cameron 81 #13 and East Cameron 84 #1. A fourth development well, East Cameron 81 #16 is planned for the second quarter of 2002. Facility construction is currently in progress at South Timbalier 314/317. The first discovery well was drilled at South Timbalier 317 during 2000 and a second exploratory well was drilled at South Timbalier 314 during 2001. KeySpan also has an interest in these wells. A third well is planned for 2002. Initial production is expected during the first quarter of 2003.

Offshore Capital Spending. Capital spending associated with our Gulf of Mexico properties during 2001 was $201.6 million, including $67.2 million for exploratory drilling, $97.3 million for development drilling, workovers and facilities construction and $37.1 million for leasehold costs, which includes capitalized interest and capitalized general and administrative costs. We did not acquire any offshore producing properties during 2001. Of our $250 million 2002 capital expenditure budget, we currently estimate we will spend approximately $96 million, which excludes capitalized interest, capitalized general and administrative costs and property acquisition costs of our capital expenditure budget of $250 million on offshore projects. KeySpan has committed to a capital budget of $15 million in 2002 for development projects associated with its working interests in wells drilled under the joint venture during 1999, 2000 and 2001.

Onshore Properties

We own significant onshore natural gas and oil properties in South Texas, the Arkoma Basin of Oklahoma and Arkansas, South Louisiana, the Appalachian Basin in West Virginia and East Texas. These properties represent interests in 1,330 gross (1,042.7 net) producing wells, approximately 85% of which we are the operator of record, and 198,781 gross (126,448 net) acres.

The following table lists our average working interest and net proved reserves for our onshore areas of operation As of December 31, 2001, representing all of our onshore reserves:

Onshore Operating Areas	Average Working Interest	Net Proved Reserves At December 31, 2001 Gas (MMcf)	Oil (MBbls)	Total (MMcfe)
South Texas:				
Charco Field	100%	149,824	60	150,184
Alexander, Haynes, Hubberd and South Trevino Fields	87%	78,936	97	79,518
Total South Texas		228,760	157	229,702
Arkoma Basin:				
Chismville/Massard Field (Arkansas)	73%	94,099	—	94,099
Wilburton, Panola and Surrounding Fields (Oklahoma)	23%	6,812	—	6,812
Total Arkoma Basin		100,911	—	100,911
Other Onshore:				
South Louisiana	55%	21,690	269	23,304
Appalachian Basin	60%	21,984	47	22,266
East Texas	53%	8,112	11	8,772
Total Other Onshore		51,786	426	54,342
Total Onshore		381,45	583	384,95

Onshore Capital Spending. We drilled or participated in the drilling of 61 successful onshore wells during 2001: 60 successful development wells and one successful exploratory well. During this same period, we drilled or participated in the drilling of 15 unsuccessful wells: three exploratory and 12 development wells. Capital spending associated with our onshore drilling program during 2001 was approximately $164.7 million, including $79.9 million for development, $4.9 million for exploration and $79.9 million for leasehold and producing property acquisition costs, which includes $69 million spent to acquire producing properties located in South Texas from Conoco Inc. in December 2001 (see Alexander, Haynes, Hubberd and South Trevino Fields, below).

Of our $250 million 2002 capital expenditure budget, we currently estimate we will spend approximately $128 million, which excludes capitalized interest, capitalized general and administrative costs and property acquisition costs, on onshore projects. For 2002, we plan to drill approximately 86 onshore wells: 56 wells in South Texas and 30 wells in the Arkoma Basin. We believe we have identified enough additional development and exploratory projects on our existing acreage to maintain an active drilling program for four years.

The following is a description of our onshore operating areas:

South Texas

Charco Field. The Charco Field is located in Zapata County, Texas. We acquired properties in the Charco Field in July 1996. We own a 100% working interest in approximately 268 active wells in the Charco Field, all of which we operate. Since the acquisition of the Charco Field in July 1996, we have used an active drilling and workover program to increase production and reserves from the field. Production has more than doubled since July 1996, from an average of 38 MMcfe per day, net to our interest, to an average of 83 MMcfe per day, net to our interest, during 2001. We have drilled 116 successful wells, added 182 Bcfe in reserves and produced 145 Bcfe since the acquisition of the Charco Field. During 2001, we successfully drilled 29 development wells and seven unsuccessful development wells. Production during December 2001 averaged approximately 78 MMcfe/day, net to our interests. Subsequent to year end, we have successfully drilled and completed five development wells, drilled two dry holes and are currently in the process of drilling three new development wells. Our production has increased to an average of 89 MMcfe/day, net to our interests, during February 2002. We are planning to keep two to three drilling rigs operating in the Charco Field during 2002.

Alexander, Haynes, Hubberd and S. Trevino Fields. On December 31, 2001,we acquired from Conoco Inc. interests in 159 producing wells together with developed and undeveloped acreage covering approximately 25,274 gross (16,885 net) acres. The properties we purchased are located in close proximity to our existing operations in the Charco Field. The Alexander and Hubberd leases are in Webb County and the Haynes and South Trevino leases are in Zapata County in South Texas. We are operator of approximately 95% of the wells we acquired and our average working interest is 87%. A recompletion and drilling program began immediately after the closing of our acquisition and currently we have three rigs in operation. Since January 1, 2002, we have commenced drilling of six wells: four have been successfully completed, one was dry and one is currently drilling. Production from the newly acquired wells is currently averaging approximately 19.0 MMcfe/day, net to our interests.

Arkoma Basin

Chismville/Massard Field. The Chismville/Massard Field is located in Logan and Sebastian Counties, Arkansas. We own working interests in approximately 240 active wells, 150 of which we operate. Working interests in these wells range from 11% to 100% and average approximately 73%. During 2001, we successfully completed 26 gross (17.1 net) development wells. In addition, we drilled or participated in four (1.7 net) unsuccessful wells. During December 2001, production averaged 17 MMcfe per day, net to our interests. We plan to maintain at least one drilling rig in the Arkoma Basin for the remainder of 2002.

Wilburton, Panola and Surrounding Fields. The Wilburton and Panola Fields are located in Latimer County, Oklahoma. We own working interests in 58 active wells, of which we operate 18 wells. Working interests in these wells range from 1% to 63% and average approximately 23%. During 2001, we drilled or participated in the drilling of five (0.8 net) successful development wells. At December 31, 2001, we had a 1% working interest in one well in progress in the South Panola Field that was a deep test of the Spiro formation. The well was drilled to 15,800 feet and subsequently deemed uneconomical. During December 2001, production averaged 4 MMcfe per day, net to our interest.

Other Onshore Areas

South Louisiana. Our South Louisiana properties are primarily located in the South Lake Arthur and Lake Pagie Fields, which are located in Vermilion and Terrebonne Parishes, respectively. We own interests in 53 producing wells, eight of which we operate. Working interests in these wells range from 2% to 70% and average 55%. During 2001, we drilled or participated in the drilling of three South Louisiana wells: one successful exploratory well located in Acadia Parish with a working interest of 33% and two unsuccessful wells, one development well with a working interest of 53% located in South Lake Arthur and one exploratory well with a working interest of 15% located in Lake Pagie. During December 2001, production from our South Louisiana properties averaged approximately 7 MMcfe/day, net to our interests.

Appalachian Area. The Belington, Clarksburg and Seneca Upshur Fields are located in Barbour, Randolph, Upshur and Mingo Counties, West Virginia. We own working interests in 668 producing wells, substantially all of which we operate. Working interests in these wells range from 6% to 100% and average approximately 60%. During December 2001, production averaged 4 MMcfe per day, net to our interests.

East Texas. Our East Texas properties are primarily located in the Willow Springs and surrounding fields. The Willow Springs Field is located in Gregg County, Texas, with the surrounding fields located in Panola and Harrison Counties, Texas. We own working interests in 33 active wells, 28 of which we operate. Working interests in these wells range from 3% to 100% and average approximately 53%. During December 2001, production averaged 2 MMcfe per day, net to our interests.

Natural Gas and Oil Reserves

The following table summarizes the estimates of our historical net proved reserves As of December 31, 2001, 2000 and 1999, and the present values attributable to these reserves at these dates. The reserve data and present values were prepared by Netherland, Sewell & Associates, Inc. and Miller and Lents, Ltd., independent petroleum engineering consultants.

Net Proved Reserves:[(1)]	As of December 31, 2001	2000	1999
	(in thousands)		
Natural gas (MMcf)	568,208	529,518	526,185
Oil (MBbls)	6,605	5,352	2,470
Total (MMcfe)	607,838	561,630	541,005
Present value of future net revenues before income taxes[(2)]	$714,416	$2,725,913	$529,671
Standardized measure of discounted future net cash flows[(3)]	$551,525	$2,064,027	$469,225

(1) Netherland, Sewell & Associates prepared reserve data for our Gulf of Mexico properties and our South Texas properties which represent present values of approximately 79%, 78% and 76%, respectively, of our reserves at December 31, 2001, 2000 and 1999. Miller and Lents prepared reserve data for the remainder of our onshore properties which represent approximately 21%, 22% and 24%, respectively, of the present values attributable to our proved reserves at December 31, 2001, 2000 and 1999.

(2) The present value of future net revenues attributable to our reserves was prepared using prices in effect at the end of the respective periods presented, discounted at 10% per annum on a pre-tax basis. Average prices per Mcf of natural gas used in making the present value determinations As of December 31, 2001, 2000 and 1999 were $2.38, $9.55 and $2.01, respectively. Average prices per Bbl of oil used in making the present value determinations As of December 31, 2001, 2000 and 1999 were $17.78, $24.69 and $22.80, respectively. Amounts include the discounted present value of our hedges in place at December 31, 2001, 2000 and 1999 of a positive $65.8 million, a negative $70.6 million and a positive $1.6 million, respectively.

(3) The standardized measure of discounted future net cash flows represents the present value of future net revenues after income tax discounted at 10% per annum and has been calculated in accordance with SFAS No. 69, "Disclosures About Oil and Gas Producing Activities" (see Note 12 — Supplemental Information on Natural Gas and Oil Exploration, Development and Production Activities (Unaudited)) and, in accordance with current SEC guidelines, does not include estimated future cash inflows from our hedging program.

In accordance with applicable requirements of the Securities and Exchange Commission, we estimate our proved reserves and future net revenues using sales prices estimated to be in effect as of the date we make the reserve estimates. We hold the estimates constant throughout the life of the properties, except to the extent a contract specifically provides for escalation. Gas prices, which have fluctuated widely in recent years, affect estimated quantities of proved reserves and future net revenues. Any estimates of natural gas and oil reserves and their values are inherently uncertain, including many factors beyond our control. The reserve data contained in this Annual Report on Form 10-K represent only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers, including those we use, may vary. In addition, estimates of reserves may be revised based upon actual production, results of future development and exploration activities, prevailing natural gas and oil prices, operating costs and other factors, which revision may be material. Accordingly, reserve estimates may be different from the quantities of natural gas and oil that we are ultimately able to recover and are highly dependent upon the accuracy of the underlying assumptions. Our estimated proved reserves have not been filed with or included in reports to any federal agency.

Drilling Activity

The following table sets forth our drilling activity on our properties for the years ended December 31, 2001, 2000 and 1999.

	Year Ended December 31,					
	2001		2000		1999	
	Gross	Net	Gross	Net	Gross	Net
Offshore Drilling Activity:						
Exploratory:						
Productive	7	4.4	8	3.0	6	1.4
Non-Productive	5	3.9	2	0.9	2	1.0
Total	12	8.3	10	3.9	8	2.4
Development:						
Productive	7	4.9	6	3.3	8	5.5
Non-Productive	1	1.0	2	0.8	—	—
Total	8	5.9	8	4.1	8	5.5
Onshore Drilling Activity:						
Exploratory:						
Productive	1	0.3	1	0.1	2	1.2
Non-Productive	3	1.0	—	—	—	—
Total	4	1.3	1	0.1	2	1.2
Development:						
Productive	60	46.9	44	36.5	31	24.3
Non-Productive	12	9.2	4	3.5	6	3.1
Total	72	56.1	48	40.0	37	27.4

Productive Wells

The following table sets forth the number of productive wells in which we owned an interest As of December 31, 2001.

	Producing Platforms		Company Operated Wells		Non-Operated Wells		Total Productive Wells	
	Operated	Non-Op	Gross	Net	Gross	Net	Gross	Net
Offshore								
Gas	29	11	50	41.3	23	5.7	73	47.0
Oil	—	—	2	1.1	—	—	2	1.1
Total	29	11	52	42.4	23	5.7	75	48.1
Onshore								
Gas			1,274	997.4	203	39.8	1,477	1,037.2
Oil			4	2.9	—	—	4	2.9
Total			1,278	1,000.3	203	39.8	1,481	1,040.1

Productive wells consist of producing wells capable of production, including gas wells awaiting connections. Wells that are completed in more than one producing horizon are counted as one well.

Acreage Data

The following table sets forth the approximate developed and undeveloped acreage in which we held a leasehold mineral or other interest As of December 31, 2001. Undeveloped acreage includes leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas or oil, regardless of whether or not the acreage contains proved reserves:

	Total Acres		Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net	Gross	Net
Offshore(1)	496,995	391,737	208,359	125,659	288,636	266,078
Onshore	198,781	126,448	184,060	119,759	14,721	6,689
Total	695,776	518,185	392,419	245,418	303,357	272,767

(1) Offshore includes acreage in federal and state waters.

Marketing and Customers

We sell substantially all of our production at market prices. We normally sell production to a relatively small number of customers, as is customary in the exploration, development and production business. However, based on the current demand for natural gas and oil, we believe that the loss of any of our major purchasers would not have a material adverse effect on our financial condition and results of operations. During the last three fiscal years, we sold natural gas and oil production representing 10% or more of our natural gas and oil revenues as follows:

	For the Year Ended December 31,		
Major Purchaser	2001	2000	1999
Dynegy Inc.	16.4%	22.5%	18.0%
Adams Resources and Energy, Inc	12.5%	14.9%	22.5%
El Paso Corporation(1)	9.5%	9.1%	7.7%

(1) Amount purchased was less than 10% of our natural gas and oil sales revenues and is included for information purposes only.

We enter into commodity swaps with unaffiliated third parties for portions of our natural gas production to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in gas prices. Please read Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — General" and Item 7A. "Quantitative and Qualitative Disclosures About Market Risk."

We transport most of our natural gas through third party gas gathering systems and gas pipelines. Transportation space on these gathering systems and pipelines is occasionally limited and at times unavailable because of repairs or improvements as a result of priority transportation agreements with gas shippers other than us. While our ability to market our natural gas has only been infrequently limited or delayed, if transportation space is restricted or is unavailable, our cash flow from the affected properties could be adversely affected. Please read the section entitled "Regulation" and "Risk Factors — Hazard Losses May Not Be Insured."

Abandonment Costs

We are responsible for our working interest share of costs to abandon natural gas and oil properties and facilities. We provide for our expected future abandonment liabilities by accruing for abandonment costs as a component of depletion, depreciation and amortization as the properties are produced. As of December 31, 2001, total undiscounted abandonment costs estimated to be incurred through the year 2013 were approximately $21 million for properties in the federal and state waters and we do not consider them significant for our onshore properties. Our estimates of abandonment costs and their timing may change as a result of many factors including, actual drilling and production results, inflation rates, and changes in environmental laws and regulations. See Note 1 — Summary of Organization and Significant Accounting Policies — New Accounting Pronouncements, for a discussion of prospective changes for accounting for abandonment costs under Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations".

The Minerals Management Service requires lessees of outer continental shelf properties to post bonds in connection with the plugging and abandonment of wells located offshore and the removal of all production facilities. Operators in the outer continental shelf waters of the Gulf of Mexico are currently required to post an area-wide bond of $3 million or $500,000 per producing lease. We are presently exempt from any requirement by the Minerals Management Service to provide supplemental bonding on our offshore leases, although we may not be able to continue to satisfy the requirements for this exemption in the future. We believe that even if we did not qualify for this exemption, the cost of any bonding requirements would not materially affect our financial condition or results of operations. The Minerals Management Service has the authority to suspend or terminate operations on federal leases for failure to comply with applicable bonding requirements or other regulations applicable to plugging and abandonment. Any suspensions or terminations of our operations could have a material adverse effect on our financial condition and results of operations.

Title to Properties

As is customary in the oil and gas industry, we conduct only a cursory review of title to farm-out acreage and to undeveloped natural gas and oil leases upon execution of the asset purchase contracts. Prior to the commencement of drilling operations, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects, we, rather than the seller of the undeveloped property, are typically responsible for curing any title defects at our expense. If we were unable to remedy or cure any title defect of a nature such that it would not be prudent to commence drilling operations on the property, we could suffer a loss of our entire investment in the property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to these properties in accordance with standards generally accepted in the oil and gas industry. Prior to completing an acquisition of producing natural gas and oil leases, we obtain title opinions on the most significant leases. Our natural gas and oil properties are subject to customary royalty interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect the value of the properties.

Third Party Contractors

In an effort to control offshore operating costs, we entered into a contract with Grasso Production Management, Inc. pursuant to which Grasso provides us with professional services relating to the supervision of the daily production operations and field personnel to operate and maintain production facilities. Our contract with Grasso was effective December 2001. From 1989 to December 2001, we maintained a similar contractual arrangement for offshore services with Operators & Consulting Services. In addition to assisting us with daily production operations, Operators & Consulting Services provided engineering and field supervision for well design, drilling, completion and workover operations and coordination and review of third party engineering and fabrication work, and installation supervision of platforms, production facilities and pipelines. These functions are now performed by our own offshore engineering department.

Competition

We encounter intense competition from other oil and gas companies in all areas of our operations, including the acquisition of producing properties and proved undeveloped acreage. Our competitors include major integrated oil and gas companies and numerous independent oil and gas companies, individuals and drilling and income programs. Many of our competitors are large, well-established companies with substantially larger operating staffs and greater capital resources than our own and which, in many instances, have been engaged in the oil and gas business for a much longer time than we have. These companies may be able to pay more for productive natural gas and oil properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.

Operating Hazards and Uninsured Risks

In our operations we may experience hazards and risks inherent in drilling for, producing and transporting of natural gas and oil. These hazards and risks may result in loss of hydrocarbons, environmental pollution, personal injury claims, and other damage to our properties and third parties and include:

- fires,
- natural disasters,
- explosions,
- encountering formations with abnormal pressures,
- blowouts,
- cratering,
- pipeline ruptures, and
- spills.

Additionally, our natural gas and oil operations located in the Gulf of Mexico may experience tropical weather disturbances, some of which can be severe enough to cause substantial damage to facilities and possibly interrupt production. As protection against operating hazards, we maintain insurance coverage against some, but not all, potential losses. Our coverage includes, but is not limited to, the operator's extra expense to include loss of well, blowouts and costs of pollution control, physical damage on assets, employer's liability, comprehensive general liability, automobile liability and worker's compensation. We believe that our insurance is adequate and customary for companies of a similar size engaged in operations similar to ours, but losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our financial condition and results of operations.

Regulation

The oil and gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and gas industry increases our cost of doing business and, consequently, affects our profitability, generally, these burdens do not appear to affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Drilling and Production. Our operations are subject to various types of regulation at federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states in which we operate also regulate:

- the location of wells,
- the method of drilling and casing wells,
- the surface use and restoration of properties upon which wells are drilled, and
- the plugging and abandoning of wells.

State laws regulate the size and shape of drilling and spacing units or proration pooling of oil and gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These regulations may limit the amount of oil and gas we can produce from our wells or limit the number of wells or the locations at which we can drill.

We conduct our operations in the Gulf of Mexico on oil and natural gas leases which are granted by the U.S. federal government and are administered by the Minerals Management Service. The Minerals Management Service issues leases through competitive bidding. The lease contracts contain relatively standardized terms and require compliance with detailed regulations of the Minerals Management Service. For offshore operations, lessees must obtain Minerals Management Service approval for exploration plans and development and production plans prior to the commencement of the 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 Minerals Management Service prior to the commencement of drilling.

The Minerals Management Service has promulgated regulations requiring offshore production facilities located on the outer continental shelf to meet stringent engineering and construction specifications, and has recently proposed additional safety-related regulations concerning the design and the operating procedures for outer continental shelf production platforms and pipelines. The Minerals Management Service also has issued regulations restricting the flaring or venting of natural gas, and has recently proposed to amend these regulations to prohibit the flaring of liquid hydrocarbons and oil without prior authorization. Similarly, the Minerals Management Service has promulgated other regulations governing the plugging and abandonment of wells located offshore and the removal of all production facilities. To cover the various obligations of lessees on the outer continental shelf, the Minerals Management Service generally requires that lessees post substantial bonds or other acceptable assurances that these obligations will be met. The Outer Continental Shelf Lands Act may generally impose liabilities on us for our offshore operations conducted on federal leases for clean-up costs and damages caused by pollution resulting from our operations. Under circumstances such as conditions deemed to be a threat or harm to the environment, the Minerals Management Service may suspend or terminate any of our operations in the affected area.

Environmental Matters and Regulation.

General. Our operations must comply with federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may:

- require the acquisition of a permit before drilling commences,
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities,
- limit or prohibit drilling activities on lands lying within wilderness, wetlands and other protected areas,
- require remedial measures to prevent pollution from former operations, such as pit closure and plugging of abandoned wells, and
- impose substantial liabilities for pollution resulting from our operations.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and the federal and state agencies frequently revise the environmental laws and regulations. Any changes that result in more stringent and costly waste handling, disposal and clean-up requirements could have a significant impact on the oil and gas industry's operating costs, including ours. We believe that we substantially comply with all current applicable environmental laws and regulations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. However, we cannot predict the passage of or quantify the potential impact of more stringent future laws and regulations at this time.

Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act affects oil and gas production activities by imposing regulations on the generation, transportation, treatment, storage, disposal and cleanup of "hazardous wastes" and on the disposal of non-hazardous wastes. Under the auspices of the Environmental Protection Agency, or the EPA, the individual states administer some or all of the provisions of the Resource Conservation and Recovery Act, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of crude oil, natural gas, or geothermal energy constitute "solid wastes," which are regulated under the less stringent non-hazardous waste provisions, but there is no guarantee that the EPA or the individual states will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation.

We believe that we are currently in substantial compliance with the requirements of the Resource Conservation and Recovery Act and related state and local laws and regulations and that we hold all necessary and up-to-date permits to the extent that our operations require them under the Resource Conservation and Recovery Act.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as the "superfund" law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substance. CERCLA also authorizes the EPA and affected parties to respond to threats to the public health or the environment and to seek recovery from responsible classes of persons for the costs of the response actions.

In the course of our operations, we generate wastes that may fall within CERCLA's definition of "hazardous substances." Therefore, we may be responsible under CERCLA for all or part of the costs to clean up sites at which such "hazardous substances" have been deposited. At this time, however, we have not been named by the EPA or alleged by any third party as being responsible for costs and liability associated with alleged releases of any "hazardous substance" at any "superfund" site.

Oil Pollution Act. The Oil Pollution Act imposes on responsible parties strict, joint and several, and potentially unlimited liability for removal costs and other damages caused by an oil spill covered by the Oil Pollution Act. The Oil Pollution Act also requires the lessee of an offshore area or a permittee whose operations take place within a covered offshore facility to establish and maintain financial responsibility of at least $35 million, which may be increased to $150 million for facilities with large worst-case spill potentials and under other circumstances, to cover liabilities related to an oil spill for which the lessee or permitttee of the offshore area is statutorily responsible. Owners of multiple facilities are required to maintain financial responsibility for only the facility with the largest potential worst-case spill. We are in compliance with the financial responsibility provisions of the Oil Pollution Act.

Federal Water Pollution Control Act. The Federal Water Pollution Control Act and related state laws provide varying civil and criminal penalties and liabilities for the unauthorized discharge of petroleum products and other pollutants to surface waters. The federal discharge permitting program also prohibits the discharge of produced water, sand and other substances related to the oil and gas industry to coastal waters. We believe that we are in substantial compliance with all pollutant, wastewater, and stormwater discharge regulations and that we hold all necessary and valid permits for the discharge of such materials from our operations.

Federal Clean Air Act. The Federal Clean Air Act restricts the emission of air pollutants and affects both onshore and offshore oil and gas operations. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to incur capital costs in order to remain in compliance. In addition, more stringent regulations governing emissions of toxic air pollutants are being developed by the EPA, and may increase the costs of compliance for some facilities. We believe that we are in substantial compliance with all air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations.

Natural Gas Sales Transportation. Historically, federal legislation and regulatory controls affect the price of the natural gas we produce and the manner in which we market our production. The Federal Energy Regulatory Commission, or FERC, has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Since 1978, various federal laws have been enacted which have resulted in the complete removal on January 1, 1993 of all price and non-price controls for sales of domestic natural gas sold in "first sales," which include all of our sales of our own production.

FERC also regulates interstate natural gas transportation rates and service conditions, which affect the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Commencing in 1985, FERC promulgated a series of orders and regulations that significantly fostered competition in the business of transporting and marketing gas. These orders and regulations induced, and ultimately required, interstate pipeline companies to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether shippers were affiliated with an interstate pipeline company. FERC's initiatives have led to the development of a competitive, unregulated, open access market for gas purchases and sales that permits all purchasers of gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach recently pursued by FERC and Congress will continue indefinitely into the future.

Under FERC's current regulatory regime, transmission services must be provided on an open-access, non-discriminatory basis at cost-based rates. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. In offshore Federal waters, gathering is regulated by FERC under the Outer Continental Shelf Lands Act. The Outer Continental Shelf Lands Act requires open access and non-discriminatory rates, but does not provide for cost-based rates. Although its policy is still in flux, FERC has recently reclassified jurisdictional transmission Facilities as nonjurisdictional gathering Facilities, which has the tendency to increase our costs of getting gas to point-of-sale locations.

Risk Factors Affecting Our Business

The Volatility of Natural Gas and Oil Prices May Affect Our Financial Results.

As an independent natural gas and oil producer, the revenues we generate from our operations are highly dependent on the price of, and demand for, natural gas and oil. Even relatively modest changes in oil and natural gas prices may significantly change our revenues, results of operations, cash flows and proved reserves. Historically, the markets for natural gas and oil have been volatile and are likely to continue to be volatile in the future. Prices for natural gas and oil may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of natural gas and oil;
- the price of foreign imports;
- overall domestic and global economic conditions;
- political and economic conditions in oil producing countries;
- the level of consumer product demand;
- weather conditions;
- domestic and foreign governmental regulations; and
- the price and availability of alternative fuels.

We cannot predict future natural gas and oil price movements. If natural gas and oil prices decline, the amount of natural gas and oil we can economically produce may be reduced, which may result in a material decline in our revenues.

We May Be Required to Take Additional Writedowns if Natural Gas and Oil Prices Decline.

We may be required under full cost accounting rules to write down the carrying value of our natural gas and oil properties when natural gas and oil prices are low or if we have substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs or deterioration in our exploration results.

For the quarter ended December 31, 2001, we were required under SEC accounting rules to take a non-cash charge to impair or reduce the carrying value of our oil and gas properties by $6.2 million ($4.0 million net of tax). The charge was primarily a result of low natural gas prices. We may be required to take additional write downs in future periods should prices not significantly improve from current levels or if we have unsuccessful drilling results.

We May Not Be Able to Meet Our Substantial Capital Requirements.

Our business is capital intensive. To maintain or increase our base of proved oil and gas reserves, we must invest a significant amount of cash flow from operations in property acquisitions, development and exploration activities. We are currently making and will continue to make substantial capital expenditures to find, develop, acquire and produce natural gas and oil reserves. Our capital expenditure budget for exploration, development and leasehold acquisitions for 2002 is estimated at approximately $250 million. This budget excludes potential property acquisitions. We believe that we will have sufficient cash provided by operating activities and available borrowing capacity under our bank credit facility to fund planned capital expenditures in 2002. If our revenues or borrowing base under the bank credit facility decrease as a result of lower natural gas and oil prices, operating difficulties or declines in reserves, we may not be able to expend the capital necessary to undertake or complete future drilling programs or acquisition opportunities unless we raise additional funds through debt or equity financings. Without continued employment of capital, our oil and gas reserves will decline. We may not be able to obtain debt or equity financing, and cash generated by operations or available under our revolving bank credit facility may not be sufficient to meet our capital requirements.

The Amount of Our Outstanding Indebtedness is Substantial and Could Have Adverse Consequences.

Our outstanding indebtedness at December 31, 2001 was \$244 million, and as of March 14, 2002 was \$251 million.

Our level of indebtedness affects our operations in a number of ways. Our bank credit facility and the indenture governing our senior subordinated notes contain covenants that require a substantial portion of our cash flow from operations to be dedicated to the payment of interest on our indebtedness. Accordingly, these funds will not be available for other purposes. Other covenants in these agreements require us to meet the financial tests specified in these agreements and establish other restrictions that limit our ability to borrow additional funds or dispose of assets. They may also affect our flexibility in planning for, and reacting to, changes in business conditions. Moreover, future acquisition and development activities may require us to significantly alter our capitalization structure, which may alter our indebtedness. Our ability to meet our debt service obligations and reduce our total indebtedness will depend upon our future performance. Our future performance, in turn, is dependent upon many factors that are beyond our control such as general economic, financial and business conditions. Our future performance may be adversely affected by these economic, financial and business conditions.

Estimates of Proved Reserves and Future Net Revenue May Change.

The estimates of proved reserves of natural gas and oil included in this document are based on various assumptions. The accuracy of any reserve estimate is a function of the quality of available data, engineering, geological interpretation and judgment and the assumptions used regarding quantities of recoverable natural gas and oil reserves and prices for crude oil, natural gas liquids and natural gas. Actual prices, production, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from those assumed in our estimates, and these variances may be significant. Any significant variance from the assumptions used could result in the actual quantity of our reserves and future net cash flow being materially different from the estimates in our reserve reports. In addition, results of drilling, testing and production and changes in crude oil, natural gas liquids and natural gas prices after the date of the estimate may result in substantial upward or downward revisions.

We May Not Be Able to Replace Reserves.

Our future success depends on our ability to find, develop and acquire natural gas and oil reserves. Without successful exploration, development or acquisition activities, our reserves and revenues will decline over time. The continuing development of reserves and acquisition activities require significant expenditures. Our cash flow from operations may not be sufficient for this purpose, and we may not be able to obtain the necessary funds from other sources. If we are not able to replace reserves at sufficient levels, the amount of credit available to us may decrease since the maximum amount of borrowing capacity available under our bank credit facility is based, at least in part, on the estimated quantities of our proved reserves.

Hazard Losses May Not Be Insured.

The natural gas and oil business involves many types of operating and environmental hazards and risks. We are insured against some, but not all, of the hazards associated with our business. We believe this is standard practice in our industry. Because of this practice, however, we may be liable or sustain losses that could be substantial due to events that are not insured.

Our Acquisition and Investment Activities May Not Be Successful.

The successful acquisition of producing properties requires assessment of reserves, future commodity prices, operating costs, potential environmental and other liabilities. These assessments may not be accurate. We review the properties we intend to acquire in a fashion that we believe is generally consistent with industry practice. This review typically includes on-site inspections and the review of environmental compliance reports filed with the Minerals Management Service. This review, however, will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We may not always perform inspections on every platform or well, and structural or environmental problems may not be observable even when an inspection is undertaken. Accordingly, we may suffer the loss of one or more acquired properties due to title deficiencies or may be required to make significant expenditures to cure environmental contamination with respect to acquired properties. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We are generally not entitled to contractual indemnification for environmental liabilities and we typically acquire structures on a property on an "as is" basis.

Our Hedging Activities May Limit the Benefit of Increased Prices.

Almost all our revenues are generated from the sale of the natural gas we produce. Periodically, we enter into hedging arrangements relating to a portion of our natural gas production to achieve a more predicable cash flow, as well as to reduce our exposure to adverse price fluctuations of natural gas. The hedging instruments we use are fixed price swaps, collars and options. While using these types of hedging instruments limits the downside risk of adverse price movements, a number of risks exist, including instances in which the benefit to revenues is limited when natural gas prices increase. For example, as a result of hedges, during the first quarter 2001 our average realized natural gas price was $5.48 per Mcf which was 80% of the average unhedged natural gas price of $6.86 per Mcf that otherwise would have been received, resulting in natural gas and oil revenues that were $30.5 million lower that the revenues we would have achieved if we had not hedged approximately 70% of our production. In addition, counter parties to our futures contract may not be able to meet the financial terms of the hedging transactions with us.

We May Incur Substantial Costs to Comply With Environmental and Other Governmental Regulations.

Environmental and other governmental regulations have increased the costs to plan, design, drill, install, operate and abandon oil and natural gas wells, offshore platforms and other facilities. We have expended and continue to expend significant resources, both financial and managerial, to comply with environmental regulations and permitting requirements. Increasingly strict environmental laws, regulations and enforcement policies and claims for damages to property, employees, other persons and the environment resulting from our operations, could result in substantial costs and liabilities in the future.

We Face Strong Competition.

As an independent natural gas and oil producer, we face strong competition in all aspects of our business. Many of our competitors are large, well-established companies that have substantially larger operating staffs and greater capital resources than we do. These companies may be able to pay more for productive natural gas and oil properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial and human resources permit.

Potential Conflicts of Interest With Our Majority Stockholder.

A variety of conflicts of interest between KeySpan and our public stockholders may arise as a result of KeySpan's ownership of approximately 67% of our common stock. KeySpan does not consider our company a core asset and may decide to sell all or part of its ownership interest in us in a transaction that does not provide our public stockholders the opportunity to sell their shares to the purchaser for a price reflecting a change-of-control premium. Further, KeySpan is in a position to control:

- the election of the entire Board of Directors;
- the outcome of the vote on all matters requiring the vote of our stockholders;
- all matters relating to our management;
- the acquisition or disposition of our assets, including the sale of our business as a whole;
- payment of dividends on our common stock;
- the future issuance of our common stock or other securities; and
- hedging, drilling, operating and acquisition expenditure plans.

The Chairman of our Board of Directors, Robert B. Catell, is also the Chairman of the Board of Directors and Chief Executive Officer of KeySpan. In addition to Mr. Catell, four of our nine other directors are currently or were previously affiliated with KeySpan: Craig G. Matthews is former Vice Chairman, President and Chief Operating Officer of KeySpan, retired March 1, 2002; Gerald Luterman is Executive Vice President and Chief Financial Officer of KeySpan; H. Neil Nichols is Senior Vice President of Corporate Development and Asset Management of KeySpan; and James Q. Riordan is currently a director of KeySpan who intends to retire from KeySpan's Board in May 2002.

Employees

As of December 31, 2001, we had 128 full time employees, 78 of whom are located at our headquarters in Houston, Texas and the remainder of whom are located at field offices. None of our employees are represented by a labor union. During 2001 and 2000, we contracted with Operators & Consulting Services to conduct all of the day to day operations of our offshore properties. In December 2001, we contracted with Grasso Production Management, Inc. to conduct these same offshore operations. Please read the section entitled "Third Party Contractors."

Offices

We currently lease approximately 69,000 square feet of office space in Houston, Texas, where our principal offices are located. In addition, we maintain field operations offices in the areas where we operate onshore properties.

Item 3. *Legal Proceedings*

We are not a party to any material pending legal proceedings, other than ordinary routine litigation incidental to our business that management believes will not have a material adverse effect on our financial condition or results of operations.

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

No matters were submitted to a vote of our security holders during the last quarter of the fiscal year ended December 31, 2001.

Part II.

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

Our common stock is traded on the New York Stock Exchange under the symbol "THX." The following table sets forth the range of high and low sales prices for each calendar quarterly period from January 1, 2000 through December 31, 2001 as reported on the New York Stock Exchange:

Year Ended December 31, 2001	High	Low
First Quarter	\$39.21	\$27.45
Second Quarter	\$38.00	\$24.90
Third Quarter	\$34.26	\$22.20
Fourth Quarter	\$35.00	\$23.10

Year Ended December 31, 2000	High	Low
First Quarter	\$20.94	\$14.50
Second Quarter	\$25.75	\$17.38
Third Quarter	\$28.31	\$21.19
Fourth Quarter	\$39.75	\$21.88

As of March 13, 2002, 30,490,680 shares of common stock were outstanding and we had approximately 44 stockholders of record and approximately 3,300 beneficial owners.

Dividends

We have not paid any cash dividends during the two most recent fiscal years and do not anticipate declaring any dividends in the foreseeable future. We expect that we will retain our cash for the operation and expansion of our business, including exploration, development and acquisition activities. Our bank credit facility and the indenture governing our $8^5/_8$% senior subordinated notes contain restrictions on the payment of dividends to holders of common stock. Accordingly, our ability to pay dividends will depend upon these restrictions and our results of operations, financial condition, capital requirements and other factors deemed relevant by the Board of Directors. Please read "Item 7. — Management's Discussion and Analysis of Financial Condition and Results of Operations."

Item 6. *Selected Financial Data*

The following table shows selected financial data derived from our consolidated financial statements for each of the five years in the period ended December 31, 2001. You should read these financial data in conjunction with Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our Consolidated Financial Statements and the related Notes.

	Years Ended December 31,				
	2001	2000	1999	1998	1997
	(in thousands, except per share data)				
Consolidated Statement of Operations Data:					
Revenues:					
Natural gas and oil revenues	$ 379,504	$ 270,595	$ 150,580	$ 127,124	$ 116,349
Other	1,353	1,738	1,147	1,123	1,297
Total revenues	380,857	272,333	151,727	128,247	117,646
Expenses:					
Lease operating	25,291	23,553	18,406	16,199	14,146
Severance tax	11,035	9,757	5,444	4,967	4,233
Depreciation, depletion and amortization	128,736	89,239	74,051	79,838	59,081
Writedown in carrying value	6,170	—	—	130,000	—
General and administrative, net	17,110	8,928	4,150	6,086	5,825
Total operating expenses	188,342	131,477	102,051	237,090	83,285
Income (loss) from operations	192,515	140,856	49,676	(108,843)	34,361
Strategic review expenses[1]	119	1,752	—	—	—
Interest expense, net	2,992	11,361	13,307	4,597	938
Income (loss) before income taxes	189,404	127,743	36,369	(113,440)	33,423
Income tax provision (benefit)	66,803	42,485	11,748	(40,754)	10,173
Net income (loss)	$ 122,601	$ 85,258	$ 24,621	$ (72,686)	$ 23,250
Net income (loss) per share	$ 4.06	$ 3.06	$ 1.03	$ (3.05)	$ 1.00
Net income (loss) per share—diluted	$ 4.00	$ 3.02	$ 0.95	$ (3.05)	$ 0.97
Weighted average shares	30,228	27,860	23,906	23,768	23,337
Weighted average shares—diluted	30,645	28,213	28,310	23,768	24,028
Ratio of earnings to fixed charges[2]	12.8x	5.5x	2.0x	N/M	5.0x

	At Year End December 31,				
	2001	2000	1999	1998	1997
	(in thousands)				
Consolidated Balance Sheet Data:					
Property, plant and equipment, net	$ 938,761	$ 705,390	$ 610,116	$ 536,582	$ 443,738
Total assets	1,059,092	837,384	678,483	569,452	491,391
Long-term debt and notes	244,000	245,000	281,000	313,000	113,000
Stockholders' equity	565,881	396,742	217,590	192,530	256,187

(1) Represents nonrecurring expenses incurred in connection with the decision to review strategic alternatives for Houston Exploration and KeySpan's investment in our Company, including the possible sale of all or a portion of Houston Exploration. Please read Note 6 — Related Party Transactions.

(2) For purposes of determining the ratio of earnings to fixed charges, earnings are defined as income (loss) before tax plus fixed charges, adjusted to exclude capitalized interest. Fixed charges consist of interest expense, whether expensed or capitalized, and an imputed or estimated interest component of rent expense. (See Exhibit 12.1)

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

General

We are an independent natural gas and oil company engaged in the exploration, development, exploitation and acquisition of domestic natural gas and oil properties. Our operations are currently focused offshore in the Gulf of Mexico and onshore in South Texas, the Arkoma Basin of Oklahoma and Arkansas, South Louisiana, the Appalachian Basin in West Virginia and East Texas. Our strategy is to utilize our technical expertise to continue to increase reserves, production and cash flows through the application of a three-pronged approach that combines an effective mix of:

- high potential offshore exploration and exploitation;
- lower risk, high impact exploitation and development drilling onshore; and
- selective opportunistic acquisitions both offshore and onshore

At December 31, 2001, our net proved reserves were 608 Bcfe, with a discounted present value of cash flows before income taxes of $714 million. Our focus is natural gas. Approximately 93% of our net proved reserves at December 31, 2001 were natural gas of which approximately 74% of our net proved reserves were classified as proved developed. We operate approximately 85% of our properties.

We began exploring for natural gas and oil in December 1985 on behalf of The Brooklyn Union Gas Company. Brooklyn Union is an indirect wholly owned subsidiary of KeySpan Corporation. KeySpan, a member of the Standard & Poor's 500 Index, is a diversified energy provider whose principal natural gas distribution and electric generation operations are located in the Northeastern United States. In September 1996 we completed our initial public offering. As of December 31, 2001, THEC Holdings Corp., an indirect wholly owned subsidiary of KeySpan, owned approximately 67% of the outstanding shares of our common stock.

As an independent oil and gas producer, our revenue, profitability and future rate of growth are substantially dependent upon prevailing prices for natural gas and oil, our ability to find and produce hydrocarbons and our ability to control and reduce costs, all of which are dependent upon numerous factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. The energy markets have historically been very volatile, as evidenced by the recent volatility of natural gas and oil prices, and there can be no assurance that commodity prices will not widely fluctuate in the future. A substantial or extended decline in natural gas and oil prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of natural gas and oil reserves that may be economically produced and access to capital.

Critical Accounting Policies and Use of Estimates

Full Cost Accounting. We use the full cost method to account for our natural gas and oil properties. Under full cost accounting, all costs incurred in the acquisition, exploration and development of natural gas and oil reserves are capitalized into a "full cost pool". Capitalized costs include costs of all unproved properties, internal costs directly related to our natural gas and oil activities and capitalized interest. We amortize these costs using a unit-of-production method. We compute the provision for depreciation, depletion and amortization quarterly by multiplying production for the quarter by a depletion rate. The depletion rate is determined by dividing our total unamortized cost base by net equivalent proved reserves at the beginning of the quarter. Unevaluated properties and related costs are excluded from our amortization base until we have made a determination as to the existence of proved reserves. Our amortization base includes estimates for future development costs as well as future abandonment and dismantlement costs.

Under full cost accounting rules, total capitalized costs are limited to a ceiling of the present value of future net revenues, discounted at 10%, 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 evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. If capitalized costs (net of accumulated depreciation, depletion and amortization) less deferred taxes are greater than the discounted future net revenues or ceiling limitation, a writedown or impairment of the full cost pool is required. A writedown of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders' equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a writedown is not reversible at a later date.

The ceiling test is calculated using natural gas and oil prices in effect as of the balance sheet date, held constant over the life of the reserves. We use derivative financial instruments that qualify for hedge accounting under Statement of Financial Accounting Standards ("SFAS") No. 133 to hedge against the volatility of natural gas prices, and in accordance with current Securities and Exchange Commission guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. In calculating the ceiling test at December 31, 2001, we estimated, using a wellhead price of $2.38 per Mcf, that our capitalized costs exceeded the ceiling limitation by $6.2 million ($4.0 million after tax). As a result, we reduced or "wrote down" the carrying value of our full cost pool and incurred a charge to earnings of $6.2 million ($4.0 million, after tax). Natural gas prices continue to be volatile and the risk that we will be required to write down our full cost pool increases when natural gas prices are depressed or if we have significant downward revisions in our estimated proved reserves.

In calculating our ceiling test at December 31, 2000 and 1999, we estimated, using a wellhead price of $9.55 per Mcf and $2.01 per Mcf, respectively, that we had a full cost ceiling "cushion" at each of the respective balance sheet dates, whereby the carrying value of our full cost pool was less that the ceiling limitation by $1.4 billion (after tax) for 2000 and $99.2 million (after tax) for 1999. No writedown is required when a cushion exists.

Estimates of proved reserves are key components of our depletion rate for natural gas and oil properties and our full cost ceiling test limitation. See Note 12 — Supplemental Information on Natural Gas and Oil Exploration, Development and Production Activities. Because there are numerous uncertainties inherent in the estimation process, actual results could differ from the estimates.

Use of Estimates. The preparation of the consolidated financial statements in conformity with generally accepted accounting principles requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Our most significant financial estimates are based on remaining proved natural gas and oil reserves.

Natural gas and oil reserve quantities represent estimates only. Under full cost accounting, we use reserve estimates to determine our full cost ceiling limitation as well as our depletion rate. We estimate our proved reserves and future net revenues using sales prices estimated to be in effect as of the date we make the reserve estimates. We hold the estimates constant throughout the life of the properties, except to the extent a contract specifically provides for escalation. Gas prices, which have fluctuated widely in recent years, affect estimated quantities of proved reserves and future net revenues. Any estimates of natural gas and oil reserves and their values are inherently uncertain, including many factors beyond our control. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based upon actual production, results of future development and exploration activities, prevailing natural gas and oil prices, operating costs and other factors, which revision may be material. Reserve estimates are highly dependent upon the accuracy of the underlying assumptions. Actual future production may be materially different from estimated reserve quantities and the differences could materially affect future amortization of natural gas and oil properties.

New Accounting Pronouncements.

SFAS No. 133. We adopted the Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" on January 1, 2001. The statement, as amended, requires companies to report the fair market value of derivatives on the balance sheet and record in income or in accumulated other comprehensive income, as appropriate, any changes in the fair market value of the derivative. We utilize cash flow hedges to reduce the risk of price volatility for our future natural gas production. Our hedges qualify for hedge accounting under SFAS 133 because they are highly effective as they are tied to the same indexes at which our natural gas production is sold. As a result, when we mark-to-market our derivative instruments at the end of each quarter, we are able to defer the gain or loss on the change in fair value in accumulated other comprehensive income, a component of stockholders' equity. At December 31, 2001, we estimated, using the New York Mercantile Exchange, or NYMEX, index price strip as of that date, that the fair market value of our hedges was $53.8 million. As a result, our balance sheet at December 31, 2001 reflects an asset of $53.8 million with a corresponding credit of $34.9 million (net of related deferred taxes of $18.9 million) in accumulated other comprehensive income, representing the fair market value of our deferred hedge gain. See Note 8 — Hedging Contracts.

The FASB has recently issued SFAS No. 141, "Business Combinations," SFAS No. 142, "Goodwill and Other Intangible Assets," SFAS No. 143, "Accounting for Asset Retirement Obligations" and SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets."

SFAS No. 141, "Business Combinations," requires the use of the purchase method of accounting for all business combinations initiated after June 30, 2001. SFAS No. 142, "Goodwill and Other Intangible Assets", addresses accounting for the acquisition of intangible assets and accounting for goodwill and other intangible assets after they have been initially recognized in the financial statements. We do not currently have goodwill or other similar intangible assets; therefore, the adoption of the new standard on January 1, 2002, has not had a material effect on our financial statements.

SFAS No. 143, "Accounting for Asset Retirement Obligations," addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 will be effective for us January 1, 2003 and early adoption is encouraged. SFAS No. 143 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. Currently, we include estimated future costs of abandonment and dismantlement in our full cost amortization base and amortize these costs as a component of our depletion expense. We are evaluating the impact the new standard will have on our financial statements.

SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," is effective for us January 1, 2002, and addresses accounting and reporting for the impairment or disposal of long-lived assets. SFAS No. 144 supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of" and APB Opinion No. 30, "Reporting the Results of Operations-Reporting the Effects of Disposal of a Segment of a Business." SFAS No. 144 retains the fundamental provisions of SFAS No. 121 and expands the reporting of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. We believe that the new standard will not have a material impact on our financial statements.

Recent Developments

Conoco Acquisition. On December 31, 2001, we completed the purchase from Conoco Inc. of natural gas and oil properties and associated gathering pipelines and equipment, together with developed and undeveloped acreage, located in Webb and Zapata counties of South Texas. The $69 million purchase price was paid in cash and financed by borrowings under our revolving bank credit facility. The properties purchased cover approximately 25,274 gross (16,885 net) acres located in the Alexander, Haynes, Hubbard and South Trevino Fields, which are in close proximity to our existing operations in the Charco Field, and represent interests in approximately 159 producing wells. We operate approximately 95% of the producing wells we acquired. Our average working interest is 87%. With this acquisition, we have expanded and expect to improve our operations in South Texas which have been an area of strategic growth for us over the past five years. Current production (for the month of February 2002) is averaging 19.0 MMcfe/day, net to our interest.

Appointment of New Executive Officer. Effective March 1, 2002, Roger B. Rice was appointed to the newly created position of Senior Vice President Human Resources and Administration. Mr. Rice has worked at Houston Exploration as a paid consultant since June 2001. Prior to joining Houston Exploration, Mr. Rice was Vice President and General Manager for Santa Fe Snyder Corporation from 1999 to 2001 where he was responsible for all onshore exploration and production activities in Texas and New Mexico. Mr. Rice had been Vice President — Human Resources with Snyder Oil Corporation from 1997 until its merger with Santa Fe Resources in 1999. From 1992 to 1997, Mr. Rice was Vice President Human Resources and Administration with Apache Corporation. From 1989 to 1992, he was Managing Consultant with Barton Raben, Inc., an executive search and consulting firm specializing in the energy industry. Previously, Mr. Rice was Vice President Administration for The Superior Oil Company and held various management positions with Shell Oil Company. He earned his Bachelor of Arts degree and Masters degree in Business Administration from Texas Technological University.

Results of Operations

The following table sets forth our historical natural gas and oil production data during the periods indicated:

	Years Ended December 31,		
	2001	2000	1999
Production:			
Natural gas (MMcf)	87,095	77,861	69,679
Oil (MBbls)	459	311	258
Total (MMcfe)	89,849	79,727	71,227
Average Sales Prices:			
Natural gas (per Mcf) realized[1]	$ 4.24	$ 3.37	$ 2.10
Natural Gas (per Mcf) unhedged	4.09	3.96	2.14
Oil (per Bbl)	22.83	27.22	16.41
Expenses (per Mcfe):			
Lease operating	$ 0.28	$ 0.30	$ 0.26
Severance tax	0.12	0.12	0.08
Depreciation, depletion and amortization	1.43	1.12	1.04
Writedown in carrying value of natural gas and oil properties	0.07	—	—
General and administrative, net	0.19	0.11	0.06

(1) Reflects the effects of hedging.

Recent Financial and Operating Results

Comparison of the Years Ended December 31, 2001 and 2000

Production. Our production increased 13% from 79,727 MMcfe for the year ended December 31, 2000 to 89,849 MMcfe for the year ended December 31, 2001. The increase in production was primarily attributable to newly developed offshore production brought on-line since the end of the second quarter of 2000.

Offshore, our production increased 30% from an average of 99 MMcfe/day during 2000 to an average of 129 MMcfe/day during 2001. This increase is primarily attributable to a full year of production at West Cameron 587, North Padre Island 883, Matagorda 704 and High Island 133/115 combined with newly developed production at Galveston Island 144, 190, 241 and 389, High Island 39 and East Cameron 83.

Onshore, our daily production rates decreased slightly by 2% from an average of 119 MMcfe/day during 2000 to an average of 117 MMcfe/day during 2001. The onshore production decrease is primarily attributable to a decline in production from our South Louisiana properties from an average of 11 MMcfe/day during 2000 to an average of 8 MMcfe/day during 2001. Average daily production from our Charco Field together with production from our Arkoma, East Texas and West Virginia properties remained unchanged at an average of 83 MMcfe/day and 26 MMcfe/day, respectively.

Natural Gas and Oil Revenues. Natural gas and oil revenues increased 40% from $270.6 million for the year ended December 31, 2000 to $379.5 million for the year ended December 31, 2001 as a result of a 26% increase in average realized natural gas prices, from $3.37 per Mcf in 2000 to $4.24 per Mcf in 2001, combined with a 13% increase in production for the same period.

Natural Gas Prices. As a result of hedging activities, we realized an average gas price of $4.24 per Mcf for the year ended December 31, 2001, which was 104% of the average unhedged natural gas price of $4.09 that otherwise would have been received, resulting in natural gas and oil revenues for the year ended December 31, 2001 that were $12.9 million higher than the revenues we would have achieved if hedges had not been in place during the period. For the corresponding period during 2000, we realized an average gas price of $3.37 per Mcf, which was 85% of the average unhedged natural gas price of $3.96 that otherwise would have been received, resulting in natural gas and oil revenues that were $46.3 million lower than the revenues we would have achieved if hedges had not been in place during the period.

Lease Operating Expenses and Severance Tax. Lease operating expenses increased 7% from $23.6 million for the year ended December 31, 2000 to $25.3 million for the year ended December 31, 2001. On an Mcfe basis, lease operating expenses decreased from $0.30 per Mcfe during 2000 to $0.28 per Mcfe during 2001. The increase in lease operating expenses for 2001 is attributable to the continued expansion of our operations, primarily from the addition of four new offshore producing blocks during 2001 combined with a full year of operations from another four blocks brought on-line during the second half of 2000. We saw service costs increase during the first half 2001 and stabilize during the later half of the year which corresponded directly with the weakening of commodity prices and a slowdown in drilling activity across the industry. The decrease in lease operating expenses per Mcfe reflects the 13% increase in production volume during 2001. Severance tax, which is a function of volume and revenues generated from onshore production, increased from $9.8 million for the year ended December 31, 2000 to $11.0 million for the year ended December 31, 2001. On an Mcfe basis, severance tax remained unchanged at $0.12 per Mcfe for each of the years ended December 31, 2000 and 2001. The increase in severance tax expense reflects higher natural gas prices received during 2001 combined with newly developed offshore production located in state waters brought on-line during the year.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased 44% from $89.2 million for the year ended December 31, 2000 to $128.7 million for the year ended December 31, 2001. Depreciation, depletion and amortization expense per Mcfe increased 28% from $1.12 during 2000 to $1.43 during 2001. The increase in depreciation, depletion and amortization expense was a result of higher production volumes combined with a higher depletion rate. The higher depletion rate is primarily a result of a higher level of capital spending during 2001 as compared to 2000 combined with the addition of fewer new reserves in 2001 from exploration and developmental drilling.

Writedown in Carrying Value of Natural Gas and Oil Properties. At December 31, 2001, we were required under full cost accounting rules to write down the carrying value of our full cost pool primarily as a result of weak natural gas prices. In calculating the ceiling test, we estimated, using a December 31, 2001 wellhead price of $2.38 per Mcf, that our capitalized costs exceeded the ceiling limitation by $6.2 million and accordingly we recorded a writedown of our full cost pool and a charge to earnings during the fourth quarter of $4.0 million, net of tax.

General and Administrative Expenses. General and administrative expenses, net of overhead reimbursements received from other working interest owners, of $3.6 million and $1.2 million for the years ended December 31, 2000 and 2001, respectively, increased 92% from $8.9 million for the year ended December 31, 2000 to $17.1 million for the year ended December 31, 2001. Included in reimbursements received from working interest owners were reimbursements totaling $2.5 million during 2000 received from KeySpan pursuant to our joint drilling venture with KeySpan (see Note 6 — Related Party Transactions). Overhead reimbursements were terminated December 31, 2000 with the expiration of the initial exploratory term of our joint drilling venture with KeySpan, and as a result we no longer receive reimbursement of general and administrative expenses from KeySpan. We capitalized general and administrative expenses directly related to oil and gas exploration and development activities of $9.6 million and $12.8 million, respectively, for the years ended December 31, 2000 and 2001. The increase in capitalized general and administrative expenses is a result of higher aggregate general and administrative expenses during 2001. Aggregate general and administrative expenses were higher during 2001 as a result of: (i) one-time payments totaling $5.2 million in connection with the termination of former executive officers' employment contracts; (ii) expansion of our workforce; and (iii) an increase in incentive compensation and benefit related expenses.

On an Mcfe basis, general and administrative expenses increased 73% from $0.11 during 2000 to $0.19 during 2001. Excluding the one-time charges taken for the termination of employment contracts totaling $5.2 million, general and administrative expenses on a per Mcfe basis would have increased 18% from $0.11 for 2000 to $0.13 for 2001. The higher rate per Mcfe during 2001 reflects the increase in aggregate general and administrative expenses caused by the effects of the termination of reimbursements received pursuant to our joint drilling venture with KeySpan which totaled $2.5 million during 2000 combined with the expansion of the Company's workforce and higher incentive compensation and benefit related expenses.

Interest Expense, Net. Interest expense, net of capitalized interest, decreased 74% from $11.4 million for the year ended December 31, 2000 to $3.0 million for the year ended December 31, 2001. Aggregate interest expense decreased 40% from $25.1 during 2000 to $15.0 million during 2001. The decrease in aggregate interest is due to a decrease in interest rates combined with (i) the paydown of $85 million in borrowings under the revolving bank credit facility during the first nine months of 2001; and (ii) the March 31, 2000 conversion of $80 million in outstanding borrowings under a revolving credit facility with KeySpan into shares of our common stock (see Note 6 — Related Party Transactions — KeySpan Credit Facility and Conversion). Capitalized interest decreased 12% from $13.7 million during 2000 to $12.0 million during 2001 and reflects the decrease in aggregate interest expense offset in part by a higher level of exploratory drilling during 2001 (our capitalized interest is a function of exploratory drilling and unevaluated properties). Interest rates on our total outstanding borrowings averaged 7.43% during 2001 compared to 8.07% in 2000.

Income Tax Provision. The provision for income taxes increased from $42.5 million for the year ended December 31, 2000 to $66.8 million for the year ended December 31, 2001 due to the 48% increase in pre-tax income during 2001 from $127.7 million during 2000 to $189.4 million during 2001 as a result of the combination of higher natural gas prices, an increase in production, a decrease in interest expense offset in part by an increase in operating expenses.

Operating Income and Net Income. For the year ended December 31, 2001, the 26% increase in natural gas prices combined with the 13% increase in production, offset in part by a 43% increase in operating expenses, caused operating income to increase 37% from $140.9 million during 2000 to $192.5 million during 2001. Correspondingly, net income increased 44% from $85.3 million for 2000 to $122.6 million for 2001 and reflects lower interest expense and higher taxes.

Comparison of the Years Ended December 31, 2000 and 1999

Production. Our production increased 12% from 71,227 MMcfe for the year ended December 31, 1999 to 79,727 MMcfe for the year ended December 31, 2000. The increase in production resulted from newly developed offshore production brought on-line since the end of the second quarter of 1999.

Offshore production increased 30% from an average of 76 MMcfe per day during 1999 to an average of 99 MMcfe per day during 2000. The increase is attributable to a full year of production from new wells drilled during 1999 at Mustang Island A-31 and West Cameron 76 and new wells drilled and completed during the second half of 2000 at West Cameron 587, North Padre Island 883, Matagorda Island 704 and High Island 133. In addition, in May 2000, we acquired incremental working interests in existing production at Vermilion 203, Mustang Island 858 and West Cameron 76.

Onshore production remained unchanged at 119 MMcfe per day during 2000 as compared to 1999. During the third quarter of 2000, we experienced delays in bringing new wells on-line at the Charco Field due to a shortage of completion equipment and crews. By the middle of the fourth quarter of 2000, crews and equipment became more readily available and we added a third drilling rig to expedite our drilling program.

Natural Gas and Oil Revenues. Natural gas and oil revenues increased 80% from $150.6 million for the year ended December 31, 1999 to $270.6 million for the year ended December 31, 2000 as a result of a 60% increase in average realized natural gas prices, from $2.10 per Mcf in 1999 to $3.37 per Mcf in 2000, combined with a 12% increase in production for the same period.

Natural Gas Prices. As a result of hedging activities, we realized an average gas price of $3.37 per Mcf for the year ended December 31, 2000, which was 85% of the average unhedged natural gas price of $3.96 that otherwise would have been received, resulting in natural gas and oil revenues for the year ended December 31, 2000 that were $46.3 million lower than the revenues we would have achieved if hedges had not been in place during the period. For the corresponding period during 1999, we realized an average gas price of $2.10 per Mcf, which was 98% of the average unhedged natural gas price of $2.14 that otherwise would have been received, resulting in natural gas and oil revenues that were $2.6 million lower than the revenues we would have achieved if hedges had not been in place during the period.

Lease Operating Expenses and Severance Tax. Lease operating expenses increased 28% from $18.4 million for the year ended December 31, 1999 to $23.6 million for the year ended December 31, 2000. On an Mcfe basis, lease operating expenses increased from $0.26 per Mcfe during 1999 to $0.30 per Mcfe during 2000. The increase in lease operating expenses and lease operating expenses on a per unit basis for the year ended December 31, 2000 is attributable to the continued expansion of our operations, particularly offshore, combined with an increase in service costs across the industry. Severance tax, which is a function of volume and revenues generated from onshore production, increased from $5.4 million for the year ended December 31, 1999 to $9.8 million for the year ended December 31, 2000. On an Mcfe basis, severance tax increased from $0.08 per Mcfe for the year ended December 31, 1999 to $0.12 per Mcfe for the corresponding twelve month period of 2000. The increase in severance tax expense and the rate per Mcfe reflects the higher natural gas prices received during 2000 as compared to 1999.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased 20% from $74.1 million for the year ended December 31, 1999 to $89.2 million for the year ended December 31, 2000. Depreciation, depletion and amortization expense per Mcfe increased 8% from $1.04 during 1999 to $1.12 during 2000. The increase in depreciation, depletion and amortization expense was a result of higher production volumes combined with a higher depletion rate. The higher depletion rate is primarily a result of a higher level of capital spending during 2000 as compared to the corresponding period of 1999 combined with the addition of fewer new reserves in 2000.

General and Administrative Expenses. General and administrative expenses, net of overhead reimbursements received from other working interest owners, of $5.7 million and $3.6 million for the years ended December 31, 1999 and 2000, respectively, increased 119% from $4.2 million for the year ended December 31, 1999 to $8.9 million for the year ended December 31, 2000. Included in reimbursements received from working interest owners were reimbursements totaling $2.5 million during 2000 and $4.8 million during 1999 received from KeySpan pursuant to the joint venture with KeySpan (please read Note 6 — Related Party Transactions). We capitalized general and administrative expenses directly related to oil and gas exploration and development activities of $5.5 million and $9.6 million, respectively, for the years ended December 31, 1999 and 2000. The increase in capitalized general and administrative expenses is a result of higher aggregate general and administrative expenses during 2000 as compared to 1999. Aggregate general and administrative expenses are higher during 2000 due to expansion of our workforce combined with an increase in incentive compensation and benefit related expenses. On an Mcfe basis, general and administrative expenses increased 83% from $0.06 for the year ended December 31, 1999 to $0.11 for the year ended December 31, 2000. The higher rate per Mcfe during 2000 reflects an increase in aggregate general and administrative expenses and the effect of the reduction in the KeySpan joint venture reimbursements offset in part by an increase in capitalized expenses. Effective December 31, 2000, pursuant to the termination of the primary term of the joint venture, we will no longer receive general and administrative reimbursements from KeySpan.

Strategic Review Expenses. During the first quarter of 2000, we recorded $1.8 million for expenses incurred in the review of strategic alternatives. In September 1999, we, along with KeySpan, our majority stockholder, announced our intention to review strategic alternatives for Houston Exploration and for KeySpan's investment in Houston Exploration. KeySpan was assessing our role within its future strategic plan, and was considering a full range of strategic transactions including the possible sale of all or a portion of its interest in us. In February 2000, we jointly announced that the review of strategic alternatives had been completed. KeySpan also announced that it planned to retain its equity position in us for the foreseeable future, however, they do not consider their investment in our company a core asset.

Interest Expense, Net. Interest expense, net of capitalized interest, decreased 14% from $13.3 million for the year ended December 31, 1999 to $11.4 million for the year ended December 31, 2000. As a result of an increase in exploratory drilling during the year ended December 31, 2000, capitalized interest increased 15% from $11.9 million during 1999 to $13.7 million during 2000. For the year ended December 31, 2000, aggregate interest expense remained unchanged at $25 million. Despite a decrease in average borrowings during 2000 due to a net pay down on our revolving bank line of credit totaling $36 million and the March 31, 2000 conversion of $80 million in outstanding borrowings under the KeySpan credit facility into shares of our common stock (please read Note 3 — Stockholders' Equity), interest expense remained unchanged due to higher interest rates during 2000 as compared to 1999. Interest rates on our total outstanding borrowings averaged 8.07% during 2000 compared to 7.23% in 1999.

Income Tax Provision. The provision for income taxes increased from $11.7 million for the year ended December 31, 1999 to $42.5 million for the year ended December 31, 2000 due to the 251% increase in pre-tax income during 2000 from $36.4 million during 1999 to $127.7 million during 2000 as a result of the combination of higher natural gas prices and increased production offset in part by the increase in operating expenses.

Operating Income and Net Income. Despite the 29% increase in operating expenses, the 12% increase in production and the 60% increase in realized natural gas prices were significant enough to cause operating income to increase 184% from $49.7 million for the year ended December 31, 1999 to $140.9 million for the year ended December 31, 2000. Correspondingly, net income increased 247% from $24.6 million for the year ended December 31, 1999 to $85.3 million for the year ended 2000.

Liquidity and Capital Resources

We have historically funded our operations, acquisitions, capital expenditures and working capital requirements from cash flows from operations, equity capital from KeySpan as well as public sources, public debt and bank borrowings. On March 31, 2000, we converted $80 million in outstanding borrowings under a revolving credit facility established in November 1998 with KeySpan into 5,085,177 shares of our common stock at a conversion price of $15.732 per share. The credit facility with KeySpan was terminated at conversion and resulted in an increase in their ownership percentage. As of December 31, 2001, KeySpan owned 67% of our outstanding common stock.

Cash Flows From Operations. As of December 31, 2001, we had working capital of $34.3 million and $105.6 million of borrowing capacity available under our revolving bank credit facility. Net cash provided by operating activities for the year ended December 31, 2001 was $358.0 million compared to $200.8 million during the corresponding twelve month period of 2000. The increase in net cash provided by operating activities was due to an increase in net income combined with a decrease in working capital, excluding the non-cash impact of the fair value of our derivative instruments. The decrease in working capital is related to the timing of cash receipts and payments and is primarily a result of the decrease in receivables, offset in part by a decrease in payables. Receivables for natural gas and oil revenues are down at year end 2001 due to lower average commodity prices during the fourth quarter of 2001 as compared to the corresponding period of 2000. Payables are lower at December 2001 due to a lower level of drilling activity and associated capital spending during the fourth quarter of 2001 as compared to the fourth quarter of 2000. Our cash position decreased during 2001 as a result of repayment of borrowings under our revolving bank credit facility of $1 million. Cash increased by $10.2 million during 2001 due to proceeds received from the issuance of common stock from the exercise of stock options. Funds used in investing activities consisted of $368.3 million for investments in property and equipment, which includes $69 million for the acquisition of producing properties in South Texas from Conoco Inc. in December 2001. As a result of these activities, cash and cash equivalents decreased $1.1 million from $9.7 million at December 31, 2000 to $8.6 million at December 31, 2001.

Our primary sources of funds for each of the past three years are reflected in the following table:

	Years Ended December 31,		
	2001	2000	1999
		(in thousands)	
Net cash provided by operating activities	$ 358,032	$ 200,791	$ 110,072
Net long-term (repayments) borrowings	(1,000)	(36,000)	48,000
Proceeds from sale of common stock, net	10,189	13,894	439

Natural Gas and Oil Capital Expenditures. Over the past three years, we have spent $698 million, which includes acquisition costs of: (i) $69 million in 2001 for the acquisition of additional producing properties in South Texas from Conoco Inc. in December 2001; (ii) $13.9 million in 2000 for the purchase of incremental working interests in various offshore producing properties; and (iii) $21 million in 1999 for an interest in West Cameron Block 587, to add 372 Bcfe of net proved reserves, representing a three-year average finding and development cost of $1.87 per Mcfe. During 2001, we spent a total of $366.4 million on the acquisition, development and exploration of natural gas and oil properties and added 136 Bcfe of net proved reserves, representing a one year average finding cost of $2.69 per Mcfe.

Our natural gas and oil capital expenditures for each of the past three years are reflected in the following table:

	Years Ended December 31,		
	2001	2000	1999
		(in thousands)	
Offshore:			
Acquisitions and leasehold	$ 37,133	$ 41,164	$ 42,246
Development	97,341	48,836	53,941
Exploration	67,172	31,164	8,450
	201,646	121,164	104,637
Onshore:			
Acquisitions and leasehold	$ 79,945	$ 5,370	$ 5,196
Development	79,915	54,499	34,024
Exploration	4,884	2,996	3,807
	164,744	62,865	43,027
Total	$ 366,390	$ 184,029	$ 147,664

Future Capital Requirements. Our capital expenditure budget for 2002 has been set at $250 million including an estimated $80 million for exploration, $145 million for development and facility construction and $25 million for leasehold acquisition costs, which includes seismic, capitalized interest and general and administrative expenses. We do not include property acquisition costs in our capital expenditure budget because the size and timing of capital requirements for acquisitions are inherently unpredictable. The capital expenditure budget includes exploration and development costs associated with projects in progress or planned for the upcoming year and amounts are contingent upon drilling success. No significant abandonment or dismantlement costs are anticipated in 2002. We will continue to evaluate our capital spending plans throughout the year. Actual levels of capital expenditures may vary significantly due to a variety of factors, including drilling results, natural gas prices, industry conditions and outlook and future acquisitions of properties. We believe cash flows from operations and borrowings under our credit facility will be sufficient to fund these expenditures. We intend to continue to selectively seek acquisition opportunities for proved reserves with substantial exploration and development potential both offshore and onshore although we may not be able to identify and make acquisitions of proved reserves on terms we consider favorable.

Shelf Registration. On May 20, 1999, we filed a "shelf" registration with the Securities and Exchange Commission to offer and sell in one or more offerings up to a total offering amount of $250 million in securities which could include shares of our common stock, shares of preferred stock or unsecured debt securities or a combination thereof. Depending on market conditions and our capital needs, we may utilize the shelf registration in order to raise capital. We would use the net proceeds received from the sale of any securities for the repayment of debt and/or to fund an acquisition. We may not be able to consummate any offerings under the shelf registration statement on acceptable terms.

Capital Structure

Revolving Bank Credit Facility. We maintain a revolving bank credit facility with a syndicate of lenders led by JP Morgan Chase, National Association. The credit facility provides a maximum commitment of $250 million, which may be limited by the amount of the borrowing base. At December 31, 2001, the borrowing base was $250 million. Up to $2.0 million of the borrowing base is available for the issuance of letters of credit to support performance guarantees. The credit facility matures on March 1, 2003 and is unsecured. At December 31, 2001, $144 million was outstanding under the credit facility and $0.4 million was outstanding in letter of credit obligations. Subsequent to December 31, 2001, we have borrowed an additional $7 million, bringing total borrowings and letters of credit to $151.4 million as of March 14, 2002.

Interest is payable on borrowings under the credit facility, at our option, at:

- a fluctuating rate, or base rate, equal to the greater of the Federal Funds rate plus 0.5% or JP Morgan Chase's prime rate, or
- a fixed rate equal to a quoted LIBOR rate plus a variable margin of 0.875% to 1.625%, depending on the amount outstanding under the credit facility.

Interest is payable at calendar quarters for base rate loans and at the earlier of maturity or three months from the date of the loan for fixed rate loans. In addition, the credit facility requires a commitment fee of:

- between 0.25% and 0.375% per annum on the unused portion of the designated borrowing base, and
- an additional fee equal to 33% of the commitment fee on the daily average amount by which the total amount of commitments exceeds the designated borrowing base.

The weighted average interest rate was 6.22%, 7.9% and 6.59%, respectively, for the years ended December 31, 2001, 2000 and 1999.

The credit facility contains covenants, including restrictions on liens and financial covenants which require us to, among other things, maintain:

- an interest coverage ratio of 2.5 to 1.0 of earnings before interest, taxes and depreciation to cash interest;
- a total debt to capitalization ratio of less than 60%, exclusive of non-cash charges; and
- sets a maximum limit of 70% on the amount of natural gas production we may hedge during any 12 month period.

In addition to maintenance of financial ratios, the credit facility restricts cash dividends and/or purchase or redemption of our stock. The credit facility also restricts the encumbering of our oil and gas assets or the pledging of those assets as collateral. As of December 31, 2001, we were in compliance with all covenants.

Senior Subordinated Notes. On March 2, 1998, we issued $100 million of $8^5/_8$% Senior Subordinated Notes due January 1, 2008. The notes bear interest at a rate of $8^5/_8$% per annum with interest payable semi-annually on January 1 and July 1. We may redeem the notes at our option, in whole or in part, at any time on or after January 1, 2003 at a price equal to 100% of the principal amount plus accrued and unpaid interest, if any, plus a specified premium which decreases yearly from 4.313% in 2003 to 0% after January 1, 2006 if the notes are redeemed prior to January 1, 2006. Upon the occurrence of a change of control, we will be required to offer to purchase the notes at a purchase price equal to 101% of the aggregate principal amount, plus accrued and unpaid interest, if any. A "change of control" is:

- the direct or indirect acquisition by any person, other than KeySpan or its affiliates, of beneficial ownership of 35% or more of total voting power as long as KeySpan and its affiliates own less than the acquiring person;
- the sale, lease, transfer, conveyance or other disposition, other than by way of merger or consolidation, in one or a series of related transactions, of all or substantially all of our assets to a third party other than KeySpan or its affiliates;
- the adoption of a plan relating to our liquidation or dissolution; or
- if, during any period of two consecutive years, individuals who at the beginning of this period constituted our board of directors, including any new directors who were approved by a majority vote of the stockholders, cease for any reason to constitute a majority of the members then in office.

The notes are general unsecured obligations and rank subordinate in right of payment to all existing and future senior debt, including the credit facility, and will rank senior or equal in right of payment to all existing and future subordinated indebtedness.

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

Natural Gas Hedging. We utilize derivative commodity instruments to hedge future sales prices on a portion of our natural gas production to achieve a more predictable cash flow, as well as to reduce our exposure to adverse price fluctuations of natural gas. Our derivatives are not held for trading purposes. While the use of hedging arrangements limits the downside risk of adverse price movements, it also limits increases in future revenues as a result of favorable price movements. The use of hedging transactions also involves the risk that the counterparties are unable to meet the financial terms of such transactions. Hedging instruments that we use are swaps, collars and options, which we generally place with major financial institutions that we believe are minimal credit risks. Our hedges are cash flow hedges and qualify for hedge accounting under SFAS 133 and, accordingly, we carry the fair market value of our derivative instruments on the balance sheet as either an asset or liability and defer gains or losses in Accumulated Other Comprehensive Income. Gains and losses are reclassified from Accumulated Other Comprehensive Income to the income statement as a component of natural gas and oil revenues in the period the hedged production occurs. If any ineffectiveness occurs, amounts are recorded directly to other income or expense. At December 31, 2001 we estimated, using a New York Mercantile Exchange (NYMEX) index price strip as of that date, that the fair market value of our hedges represented an asset of $53.8 million or $34.9 million net of deferred taxes.

The following table summarizes the change in the fair value of our derivative instruments from our adoption of SFAS 133 on January 1, 2001 to year end December 31, 2001.

Change in Fair Value of Derivatives Instruments	2001
Fair value of contracts at January 1 and adoption of SFAS 133	$ (75,069)
Gain on contracts realized	12,926
Fair value of new contracts when entered	5,931
Changes in fair values due to changes in valuation assumptions	—
Other changes in fair values	109,983
Fair value of contracts outstanding at December 31	$ 53,771

The following table summerizes on a monthly basis our hedges for 2002 and 2003. All amounts are in thousands, except for prices. For 2002, we have hedged approximately 60% of our estimated production or a total of 170,000 MMBtu/day at an effective floor of $3.436 and an effective ceiling of $4.942 for the months January through March. For the months April through December 2002, we have hedged approximately 70% of our estimated production or a total of 190,000 MMBtu/day at an effective floor of $3.389 and an effective ceiling of $4.801. Our effective floor for 2002 includes premiums paid for derivative instruments totaling $5.9 million. We will amortize the premiums to expense during 2002 at a rate of approximately $0.5 million per month. For the year 2003, we have 60,000 MMBtu/day hedged at an effective floor of $3.229 and an effective ceiling of $3.486.

Period	Fixed Price Swaps Volume (MMbtu)	Fixed Price Swaps NYMEX Contract Price	Collars Volume (MMbtu)	Collars NYMEX Contract Price Avg Floor	Collars NYMEX Contract Price Avg Ceiling
January 2002	930	$ 3.010	4,340	$ 3.643	$ 5.356
February 2002	840	3.010	3,920	3.643	5.356
March 2002	930	3.010	4,340	3.643	5.356
April 2002	900	3.010	4,800	3.561	5.137
May 2002	930	3.010	4,960	3.561	5.137
June 2002	900	3.010	4,800	3.561	5.137
July 2002	930	3.010	4,960	3.561	5.137
August 2002	930	3.010	4,960	3.561	5.137
September 2002	900	3.010	4,800	3.561	5.137
October 2002	930	3.010	4,960	3.561	5.137
November 2002	900	3.010	4,800	3.561	5.137
December 2002	930	3.010	4,960	3.561	5.137
January 2003	1,240	$3.194	620	$ 3.300	$ 4.070
February 2003	1,120	3.194	580	3.300	4.070
March 2003	1,240	3.194	620	3.300	4.070
April 2003	1,200	3.194	600	3.300	4.070
May 2003	1,240	3.194	620	3.300	4.070
June 2003	1,200	3.194	600	3.300	4.070
July 2003	1,240	3.194	620	3.300	4.070
August 2003	1,240	3.194	620	3.300	4.070
September 2003	1,200	3.194	600	3.300	4.070
October 2003	1,240	3.194	620	3.300	4.070
November 2003	1,200	3.194	600	3.300	4.070
December 2003	1,240	3.194	620	3.300	4.070

These hedging transactions are settled based upon the NYMEX price on the final trading day of the month. In order to determine fair market value of our derivative instruments, we obtain market to market quotes from external counterparties.

With respect to any particular swap transaction, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price for the transaction, and we are required to make payment to the counterparty if the settlement price for any settlement period is greater than the swap price for the transaction. For any particular collar transaction, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price for the transaction, and we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price for the transaction. We are not required to make or receive any payment in connection with a collar transaction if the settlement price is between the floor and the ceiling. For option contracts, we have the option, but not the obligation, to buy contracts at the strike price up to the day before the last trading day for that NYMEX contract.

For a description of some of the bonding requirements related to offshore production proposed by the Minerals Management Service, please read "Items 1 and 2. Business and Properties — Environmental Matters and Regulation."

Item 8. *Financial Statements*

The financial statements required by this item are incorporated under Item 14 in part IV of this report.

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

None.

Part III.

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

The information required by this Item 10 that relates to our directors and executive officers is incorporated by reference from the information appearing under the captions "Election of Directors" and "Executive Officers" in our definitive proxy statement which involves the election of directors and is to be filed with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934 within 120 days of the end of our fiscal year on December 31, 2001.

Item 11. *Executive Compensation*

The information required by this Item 11 that relates to the management is incorporated by reference from the information appearing under the captions "Executive Compensation" and "Election of Directors - Director's Meetings and Compensation" in our definitive proxy statement which involves the election of directors and is to be filed with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934 within 120 days of the end of our fiscal year on December 31, 2001. Notwithstanding the foregoing, in accordance with the instructions to Item 402 of Regulation S-K, the information contained in our proxy statement under the subheading "Report of the Compensation Committee of the Board of Directors" and "Performance Graph" shall not be deemed to be filed as part of or incorporated by reference into this Form 10-K.

Item 12. *Security Ownership of Beneficial Owners and Management*

The information required by this Item 12 that relates to the ownership by management and others of securities is incorporated by reference from the information appearing under the caption "Security Ownership of Certain Beneficial Owners and Management" in our definitive proxy statement which involves the election of directors and is to be filed with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934 within 120 days of the end of our fiscal year on December 31, 2001.

Item 13. *Certain Relationships and Related Transactions*

The information required by this Item 13 that relates to business relationships and transactions with management and other related parties is incorporated by reference from the information appearing under the captions "Certain Transactions" and "Executive Compensation — Compensation Committee Interlocks and Insider Participation" in our definitive proxy statement which involves the election of directors and is to be filed with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934 within 120 days of the end of our fiscal year on December 31, 2001.

Part IV.

Item 14. *Exhibits, Financial Statement Schedules and Reports on Form 8-K*

(a) Documents Filed as a Part of this Report

1. Financial Statements:

All other schedules are omitted because they are not applicable, not required, or because the required information is included in the financial statements or related notes.

2. Exhibits:

See Index of Exhibits on page F-29 for a description of the exhibits filed as a part of this report.

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.

THE HOUSTON EXPLORATION COMPANY

By: /s/ William G. Hargett
William G. Hargett
President and Chief Executive Officer

Date: March 12, 2002

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/ William G. Hargett William G. Hargett	President, Chief Executive Officer and Director (Principal Executive Officer)	March 12, 2002
/s/ James F. Westmoreland James F. Westmoreland	Vice President, Chief Accounting Officer and Secretary (Principal Financial Officer and Principal Accounting Officer)	March 11, 2002
/s/ Robert B. Catell Robert B. Catell	Chairman of the Board of Directors	March 11, 2002
/s/ Gordon F. Ahalt Gordon F. Ahalt	Director	March 13, 2002
/s/ David G. Elkins David G. Elkins	Director	March 11, 2002
/s/ Russell D. Gordy Russell D. Gordy	Director	March 13, 2002
/s/ Gerald Luterman Gerald Luterman	Director	March 13, 2002
/s/ Craig G. Matthews Craig G. Matthews	Director	March 13, 2002
/s/ H. Neil Nichols H. Neil Nichols	Director	March 13, 2002
/s/ James Q. Riordan James Q. Riordan	Director	March 13, 2002
/s/ Donald C. Vaughn Donald C. Vaughn	Director	March 11, 2002

Glossary of Oil and Gas Terms

The definitions set forth below apply to the indicated terms as used in this Annual Report on Form 10-K. All volumes of natural gas referred to are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to crude oil or other liquid hydrocarbons.

Bbl/d. One barrel per day.

Bcf. Billion cubic feet.

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.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

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

Developed acreage. The number of acres allocated or assignable to producing wells or wells capable of production.

Developed well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the 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 where the owner of a working interest in an natural gas and oil lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farm-in" while the interest transferred by the assignor is a "farm-out."

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature 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.

Intangible Drilling and Development Costs. Expenditures made by an operator for wages, fuel, repairs, hauling, supplies, surveying, geological works etc., incident to and necessary for the preparing for and drilling of wells and the construction of production facilities and pipelines.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

MBbls/d. One thousand barrels of crude oil or other liquid hydrocarbons per day.

Mcf. One thousand cubic feet.

Mcf/d. One thousand cubic feet per day.

Mcfe. One 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.

Mcfe/d. One 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 per day.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMbtu. One million Btus.

MMMbtu. One billion Btus.

MMcf. One million cubic feet.

MMcf/d. One million cubic feet per day.

MMcfe. One 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 gross wells.

Oil. Crude oil and condensate.

Present value. When used with respect to natural gas and oil reserves, the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date indicated, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

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

Proved developed nonproducing 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 able to produce to market.

Proved reserves. The estimated quantities of crude oil, natural gas and natural gas liquids which 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 location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

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 from recompletion.

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

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

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

Tangible Drilling and Development Costs. Cost of physical lease and well equipment and structures. The costs of assets that themselves have a salvage value.

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

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

Workover. Operations on a producing well to restore or increase production.

Index to Financial Statements

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

We have audited the accompanying consolidated balance sheets of The Houston Exploration Company (a Delaware corporation and an indirect 67%-owned subsidiary of KeySpan Corporation) and subsidiary, As of December 31, 2001 and 2000, and the related consolidated statements of operations, stockholders' equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of The Houston Exploration Company and subsidiary, As of December 31, 2001 and 2000, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As discussed in the Note 1 to the Consolidated Financial Statements, the Company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities, as amended", on January 1, 2001.

ARTHUR ANDERSEN LLP

New York, New York
February 4, 2002

THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31, 2001	December 31, 2000
	(in thousands, except share data)	
Assets:		
Cash and cash equivalents	$ 8,619	$ 9,675
Accounts receivable	43,847	100,966
Accounts receivable — Affiliate	635	13,635
Derivative financial instruments	53,771	—
Inventories	1,149	1,923
Prepayments and other	2,959	1,913
Total current assets	110,980	128,112
Natural gas and oil properties, full cost method		
Unevaluated properties	177,987	142,890
Properties subject to amortization	1,493,293	1,162,000
Other property and equipment	8,265	9,852
	1,679,545	1,314,742
Less: Accumulated depreciation, depletion and amortization	(740,784)	(609,352)
	938,761	705,390
Other assets	9,351	3,882
Total Assets	$1,059,092	$ 837,384
Liabilities:		
Accounts payable and accrued expenses	$ 76,666	$ 108,366
Total current liabilities	76,666	108,366
Long-term debt and notes	244,000	245,000
Deferred federal income taxes	172,169	87,040
Other deferred liabilities	376	236
Total Liabilities	493,211	440,642
Commitments and Contingencies (See Note 10)		
Stockholders' Equity:		
Common Stock, $.01 par value, 50,000,000 shares authorized and 30,463,230 shares issued and outstanding at December 31, 2001 and 29,829,050 shares issued and outstanding at December 31, 2000	305	298
Additional paid-in capital	336,977	325,205
Unearned compensation	(192)	—
Retained earnings	193,840	71,239
Accumulated other comprehensive income	34,951	—
Total Stockholders' Equity	565,881	396,742
Total Liabilities and Stockholders' Equity	$1,059,092	$ 837,384

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

THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2001	2000	1999
	(in thousands, except per share data)		
Revenues:			
Natural gas and oil revenues	$ 379,504	$ 270,595	$ 150,580
Other	1,353	1,738	1,147
Total revenues	380,857	272,333	151,727
Operating expenses:			
Lease operating	25,291	23,553	18,406
Severance tax	11,035	9,757	5,444
Depreciation, depletion and amortization	128,736	89,239	74,051
Writedown in carrying value of natural gas and oil	6,170	—	—
General and administrative, net	17,110	8,928	4,150
Total operating expenses	188,342	131,477	102,051
Income from operations	192,515	140,856	49,676
Strategic review expenses	119	1,752	—
Interest expense, net	2,992	11,361	13,307
Income before income taxes	189,404	127,743	36,369
Provision for federal income taxes	66,803	42,485	11,748
Net income	$ 122,601	$ 85,258	$ 24,621
Net income per share	$ 4.06	$ 3.06	$ 1.03
Net income per share— assuming dilution	$ 4.00	$ 3.02	$ 0.95
Weighted average shares outstanding	30,228	27,860	23,906
Weighted average shares outstanding — assuming dilution	30,645	28,213	28,310

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

THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(in thousands)

Stockholders' Equity	Common Stock	Additional Paid-In-Capital	Retained Earnings (Deficit)	Unearned Compensation	Other Accumulated Comprehensive Income	Total Stockholders' Equity
Balance December 31, 1998	$ 239	$ 230,931	$(38,640)	$ —	$ —	$ 192,530
Common stock[1]	—	439	—	—	—	439
Net income	—	—	24,621	—	—	24,621
Balance at December 31, 1999	$ 239	$ 231,370	$(14,019)	$ —	$ —	$ 217,590
Common stock[1][2]	59	93,835	—	—	—	93,894
Net income	—	—	85,258	—	—	85,258
Balance December 31, 2000	$ 298	$ 325,205	$ 71,239	$ —	$ —	$ 396,742
Common stock[1][3]	7	10,438	—	—	—	10,445
Unamortized value of restricted stock	—	—	—	(192)	—	(192)
Tax benefit from non-qualified stock options	—	1,334	—	—	—	1,334
Unrealized gains on derivative instruments, net of taxes	—	—	—	—	34,951	34,951
Net income	—	—	122,601	—	—	122,601
Balance December 31, 2001	$ 305	$ 336,977	$ 193,840	$ (192)	$ 34,951	$ 565,881

(1) Common stock issued through the exercise of stock options. See Note 4 — Stock Option Plans.

(2) Includes 5,085,177 shares issued on March 31, 2000 to our majority stockholder, KeySpan Corporation, pursuant to the conversion of $80 million in outstanding borrowings under a revolving credit facility with KeySpan. See Note 3 — Stockholders' Equity.

(3) Includes 10,000 shares of restricted stock issued to our President and Chief Executive Officer in April 2001 at $25.58 per share. See Note 6 — Related Party Transactions.

Comprehensive Income	Years Ended December 31, 2001	2000	1999
Net income	$ 122,601	$ 85,258	$ 24,621
Other comprehensive income, net of taxes			
Unrealized gain on derivative instruments, net of taxes[1]	34,951	—	—
Comprehensive income	$ 157,552	$ 85,258	$ 24,621

(1) Unrealized gain on derivative instruments net of $18.8 million in tax expense.

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

THE HOUSTON EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2001	2000	1999
	(in thousands)		
Operating Activities:			
Net income	$ 122,601	$ 85,258	$ 24,621
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	128,736	89,239	74,051
Writedown in carrying value of natural gas and oil properties	6,170	—	—
Deferred income tax expense	67,643	43,303	12,709
Stock compensation expense	64	—	—
Changes in operating assets and liabilities:			
Decrease (increase) in accounts receivable	70,119	(67,369)	(24,045)
Decrease (increase) in inventories	774	(954)	(54)
Increase in prepayments and other	(1,046)	(831)	(328)
Increase in other assets and other deferred liabilities	(5,329)	(217)	(143)
(Decrease) increase in accounts payable and accrued expenses	(31,700)	52,362	23,261
Net cash provided by operating activities	358,032	200,791	110,072
Investing Activities:			
Investment in property and equipment	(368,277)	(184,512)	(147,943)
Dispositions and other	—	—	289
Net cash used in investing activities	(368,277)	(184,512)	(147,654)
Financing Activities:			
Proceeds from long-term borrowings	172,000	32,000	64,000
Repayments of long-term borrowings	(173,000)	(68,000)	(16,000)
Proceeds from issuance of common stock	10,189	13,894	439
Net cash provided by (used in) financing activities	9,189	(22,106)	48,439
(Decrease) increase in cash and cash equivalents	(1,056)	(5,827)	10,857
Cash and cash equivalents, beginning of year	9,675	15,502	4,645
Cash and cash equivalents, end of year	$ 8,619	$ 9,675	$ 15,502
Cash paid for interest	$ 14,777	$ 25,490	$ 23,970
Cash paid for federal income taxes	$ 475	$ —	$ —

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

NOTE 1 — Summary of Organization and Significant Accounting Policies

Organization

We are an independent natural gas and oil company engaged in the exploration, development, exploitation and acquisition of domestic natural gas and oil properties. Our operations are currently focused offshore in the Gulf of Mexico and onshore in South Texas, the Arkoma Basin of Oklahoma and Arkansas, South Louisiana, the Appalachian Basin in West Virginia and East Texas. Our strategy is to utilize our technical expertise to continue to increase reserves, production and cash flows through the application of a three-pronged approach that combines an effective mix of:

- high potential offshore exploration and exploitation;
- lower risk, high impact exploitation and development drilling onshore; and
- selective opportunistic acquisitions both offshore and onshore

At December 31, 2001, our net proved reserves were 608 Bcfe, with a discounted present value of cash flows before income taxes of $714 million. Our focus is natural gas. Approximately 93% of our net proved reserves at December 31, 2001 were natural gas of which approximately 74% of our net proved reserves were classified as proved developed. We operate approximately 85% of our properties.

We began exploring for natural gas and oil in December 1985 on behalf of The Brooklyn Union Gas Company. Brooklyn Union is an indirect wholly owned subsidiary of KeySpan Corporation. KeySpan, a member of the Standard & Poor's 500 Index, is a diversified energy provider whose principal natural gas distribution and electric generation operations are located in the Northeastern United States. In September 1996 we completed our initial public offering. As of December 31, 2001, THEC Holdings Corp., an indirect wholly owned subsidiary of KeySpan, owned approximately 67% of the outstanding shares of our common stock.

Principles of Consolidation

The consolidated financial statements include our accounts and the accounts of our wholly owned subsidiary, Seneca Upshur Petroleum Company. All significant intercompany balances and transactions have been eliminated.

Reclassifications

We have made some reclassifications of prior years to conform with current year presentation.

Use of Estimates

The preparation of the consolidated financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Our most significant financial estimates are based on remaining proved natural gas and oil reserves. Estimates of proved reserves are key components of our depletion rate for natural gas and oil properties and our full cost ceiling test limitation. See Note 12 — Supplemental Information on Natural Gas and Oil Exploration, Development and Production Activities. Because there are numerous uncertainties inherent in the estimation process, actual results could differ from the estimates.

Net Income Per Share

Basic earnings per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding during the period. No dilution for any potentially dilutive securities is included. Diluted earnings per share assumes the conversion of all potentially dilutive securities and is calculated by dividing net income, as adjusted, by the sum of the weighted average number of shares of common stock outstanding plus all potentially dilutive securities.

Under the requirements of Statement of Financial Accounting Standards No. 128, our earnings per share are as follows:

	Years Ended December 31,		
	2001	2000	1999
	(in thousands, except per share data)		
Net income	$122,601	$ 85,258	$ 24,621
Interest savings on convertible debt	—	—	2,398
Net income, as adjusted	$122,601	$ 85,258	$ 27,019
Weighted average shares outstanding	30,228	27,860	23,906
Add dilutive securities:			
Options	417	353	206
Convertible debt	—	—	4,198
Total weighted average shares outstanding and dilutive securities	30,645	28,213	28,310
Net income per share	$ 4.06	$ 3.06	$ 1.03
Net income per share — assuming dilution	$ 4.00	$ 3.02	$ 0.95

Natural Gas and Oil Properties

Full Cost Accounting. We use the full cost method to account for our natural gas and oil properties. Under full cost accounting, all costs incurred in the acquisition, exploration and development of natural gas and oil reserves are capitalized into a "full cost pool". Capitalized costs include costs of all unproved properties, internal costs directly related to our natural gas and oil activities and capitalized interest. We amortize these costs using a unit-of-production method. We compute the provision for depreciation, depletion and amortization quarterly by multiplying production for the quarter by a depletion rate. The depletion rate is determined by dividing our total unamortized cost base by net equivalent proved reserves at the beginning of the quarter. Unevaluated properties and related costs are excluded from our amortization base until we have made a determination as to the existence of proved reserves. Our amortization base includes estimates for future development costs as well as future abandonment and dismantlement costs.

Under full cost accounting rules, total capitalized costs are limited to a ceiling of the present value of future net revenues, discounted at 10%, 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 evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. If capitalized costs (net of accumulated depreciation, depletion and amortization) less deferred taxes are greater than the discounted future net revenues or ceiling limitation, a writedown or impairment of the full cost pool is required. A writedown of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders' equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a writedown is not reversible at a later date.

The ceiling test is calculated using natural gas and oil prices in effect as of the balance sheet date, held flat over the life of the reserves. We use derivative financial instruments that qualify for hedge accounting under Statement of Financial Accounting Standards ("SFAS") No. 133 to hedge against the volatility of natural gas prices, and in accordance with current Securities and Exchange Commission guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. In calculating the ceiling test at December 31, 2001, we estimated, using a wellhead price of $2.38 per Mcf, that our capitalized costs exceeded the ceiling limitation by $6.2 million ($4.0 million after tax). As a result, we reduced or "wrote down" the carrying value of our full cost pool and incurred a charge to earnings of $6.2 million ($4.0 million, after tax). Natural gas prices continue to be volatile and the risk that we will be required to writedown our full cost pool increases when natural gas prices are depressed or if we have significant downward revisions in our estimated proved reserves.

In calculating our ceiling test at December 31, 2000 and 1999, we estimated, using a wellhead price of $9.55 per Mcf and $2.01 per Mcf, respectively, that we had a full cost ceiling "cushion" at each of the respective balance sheet dates, whereby the carrying value of our full cost pool was less that the ceiling limitation by $1.4 billion (after tax) for 2000 and $99.2 million (after tax) for 1999. No writedown is required when a cushions exists.

Proceeds from the dispositions of natural gas and oil properties are recorded as reductions of capitalized costs, with no gain or loss recognized, unless the adjustments significantly alter the relationship of unamortized capitalized costs and total proved reserves.

Other Property and Equipment

Other property and equipment include the costs of West Virginia gathering facilities which are depreciated using the unit-of-production basis utilizing estimated proved reserves accessible to the facilities. Also included in other property and equipment are costs of office furniture, fixtures and equipment which are recorded at cost and depreciated using the straight-line method over estimated useful lives ranging between two to five years.

Income Taxes

We determine deferred taxes based on the estimated future tax effect of differences between the financial statement and tax basis of assets and liabilities given the provisions of enacted tax laws. These differences relate primarily to

- intangible drilling and development costs associated with natural gas and oil properties, which are capitalized and amortized for financial reporting purposes and expensed as incurred for tax reporting purposes and
- provisions for depreciation and amortization for financial reporting purposes that differ from those used for income tax reporting purposes.

Inventories

Inventories consist primarily of tubular goods used in our operations and are stated at the lower of the specific cost of each inventory item or market value.

General and Administrative Costs and Expenses

We receive reimbursement for administrative and overhead expenses incurred on behalf of other working interest owners on properties we operate. These reimbursements totaling $1.2 million, $3.6 million and $5.7 million for the years ended December 31, 2001, 2000 and 1999, respectively, were allocated as reductions to general and administrative expenses. Included in reimbursements received during 2000 and 1999 are general and administrative reimbursements received from KeySpan pursuant to the joint exploration agreement with KeySpan, see Note 6 –

Related Party Transactions of $2.5 million and $4.8 million, respectively. The capitalized general and administrative costs directly related to our acquisition, exploration and development activities, during 2001, 2000 and 1999, aggregated $12.8 million, $9.6 million and $5.5 million, respectively.

Capitalization of Interest

We capitalize interest related to our unevaluated natural gas and oil properties and some properties under development which are not currently being amortized. For the years ended December 31, 2001, 2000 and 1999 we capitalized interest costs of $12.0 million, $13.7 million and $11.9 million, respectively.

Revenue Recognition and Gas Imbalances

We use the entitlements method of accounting for the recognition of natural gas and oil revenues. Under this method of accounting, income is recorded based on our net revenue interest in production or nominated deliveries. We incur production gas volume imbalances in the ordinary course of business. Net deliveries in excess of entitled amounts are recorded as liabilities, while net under deliveries are reflected as assets. Imbalances are reduced either by subsequent recoupment of over-and under deliveries or by cash settlement, as required by applicable contracts. Production imbalances are marketed-to-market at the end of each month using market prices as of the end of the period. Our production imbalances represented liabilities of $376,000 and $236,000, respectively, at December 31, 2001 and 2000.

Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. On the balance sheet, we report cash and cash equivalents, accounts receivable and accounts payable at cost or carrying value, which approximates fair value due to the short maturity of these instruments. Pursuant to our adoption of SFAS 133 on January 1, 2001, our derivative financial instruments are reported on the balance sheet at fair market value.

Hedging Contracts

We utilize derivative commodity instruments to hedge future sales prices on a portion of our natural gas production in order to achieve a more predictable cash flow and to reduce our exposure to adverse price fluctuations. Our derivatives are not held for trading purposes. While the use of hedging arrangements limits the downside risk of adverse price movements, it also limits increases in future revenues from possible favorable price movements. Hedging instruments that we use include swaps, costless collars and options, which we generally place with major financial institutions that we believe are minimal credit risks. Our hedging strategies meet the criteria for hedge accounting treatment under SFAS No. 133, "Accounting for Derivative and Hedging Activities". Accordingly, we mark-to-market our derivative instruments at the end of each quarter, and defer the effective portion of the gain or loss on the change in fair value of our derivatives in Accumulated Other Comprehensive Income, a component of stockholders' equity. We recognize gains and losses when the underlying transaction is completed, at which time these gains and losses are reclassified from accumulated other comprehensive income and included in earnings as a component of natural gas revenues in accordance with the underlying hedged transaction. If hedging instruments cease to meet the criteria for deferred recognition, any gains or losses would be currently recognized in earnings. At December 31, 2001, we estimated, using the New York Mercantile Exchange, or NYMEX, index price strip as of that date, that the fair market value of our derivative instruments was $53.8 million. As a result, our balance sheet at December 31, 2001 reflects an asset of $53.8 million with a corresponding credit of $34.9 million (net of related deferred taxes of $18.9 million) in accumulated other comprehensive income, representing the fair market value of our deferred hedge gain. See Note 8 — Hedging Contracts.

Concentration of Credit Risk

Substantially all of our accounts receivable result from natural gas and oil sales or joint interest billings to third parties in the oil and gas industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. Historically, we have not experienced credit losses on these receivables. We are exposed to credit risk in the event of nonperformance by counterparties to futures and swaps contracts. We believe that the credit risk related to the futures and swap contracts is no greater than that associated with the primary contracts which we hedge, as these contracts are with major investment grade financial institutions, and that elimination of the price risk lowers our overall business risk.

Stock Options

We account for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board ("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 common stock at the date of the grant over the amount the employee must pay to acquire the common stock. If the exercise price of a stock option is equal to the fair market value at the time of grant, no compensation expense is incurred. See Note 4 — Stock Options — Fair Value of Employee Stock-Based Compensation for disclosure had stock options been accounted for based upon the fair value provisions of the Financial Accounting Standards Board ("FASB") SFAS No. 123, "Accounting for Stock-Based Compensation."

New Accounting Pronouncements

We adopted the FASB SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" on January 1, 2001. The statement, as amended, requires companies to report the fair market value of derivatives on the balance sheet and record in income or in accumulated other comprehensive income, as appropriate, any changes in the fair market value of the derivative. We utilize cash flow hedges to reduce the risk of price volatility for our future natural gas production. Our hedges qualify for hedge accounting under SFAS 133 because they are highly effective as they are tied to the same indexes at which our natural gas production is sold. As a result, when we mark-to-market our derivative instruments at the end of each quarter, we are able to defer the gain or loss on the change in fair value in Accumulated Other Comprehensive Income, a component of shareholders' equity.

The FASB has recently issued SFAS No. 141, "Business Combinations," SFAS No. 142, "Goodwill and Other Intangible Assets," SFAS No. 143, "Accounting for Asset Retirement Obligations" and SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets."

SFAS No. 141, "Business Combinations," requires the use of the purchase method of accounting for all business combinations initiated after June 30, 2001. SFAS No. 142, "Goodwill and Other Intangible Assets", addresses accounting for the acquisition of intangible assets and accounting for goodwill and other intangible assets after they have been initially recognized in the financial statements. We do not currently have goodwill or other similar intangible assets; therefore, the adoption of the new standard on January 1, 2002, has not had a material effect on our financial statements.

SFAS No. 143, "Accounting for Asset Retirement Obligations," addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 will be effective for us January 1, 2003 and early adoption is encouraged. SFAS No. 143 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. Currently, we include estimated future costs of abandonment and dismantlement in our full cost amortization base and amortize these costs as a component of our depletion expense. We are evaluating the impact the new standard will have on our financial statements.

SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," is effective for us January 1, 2002, and addresses accounting and reporting for the impairment or disposal of long-lived assets. SFAS No. 144 supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of" and APB Opinion No. 30, "Reporting the Results of Operations-Reporting the Effects of Disposal of a Segment of a Business." SFAS No. 144 retains the fundamental provisions of SFAS No. 121 and expands the reporting of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. We believe that the new standard will not have a material impact on our financial statements.

NOTE 2 — Long-Term Debt and Notes

	As of December 31,	
	2001	2000
	(in thousands)	
Senior Debt:		
Bank revolving credit facility	$ 144,000	$ 145,000
Subordinated Debt:		
$8^5/_8$% Senior Subordinated Notes due 2008	100,000	100,000
Total long-term debt and notes	$ 244,000	$ 245,000

The carrying amount of borrowings outstanding under the revolving bank credit facility approximates fair market value as interest rates are tied to current market rates. At December 31, 2001, the quoted market value of the $8^5/_8$% senior subordinated notes was 102% of the $100 million carrying value or $102 million.

Credit Facility

We maintain a revolving bank credit facility with a syndicate of lenders led by JPMorgan Chase, National Association. The credit facility, as amended, provides a maximum commitment of $250 million, subject to borrowing base limitations. At December 31, 2001, the borrowing base amount was $250 million. Up to $2.0 million of the borrowing base is available for the issuance of letters of credit to support performance guarantees. The credit facility matures on March 1, 2003 and is unsecured. At December 31, 2001, $144 million was outstanding under the credit facility and $0.4 million was outstanding in letter of credit obligations. Subsequent to year end December 31, 2001, we borrowed an additional $7.0 million, bringing outstanding borrowings and letter of credit obligations to $151.4 million as of March 14, 2002.

Interest is payable on borrowings under the credit facility, at our option, at:

- a fluctuating rate, or base rate, equal to the greater of the Federal Funds rate plus 0.5% or JP Morgan Chase's prime rate, or
- a fixed rate equal to a quoted LIBOR rate plus a variable margin of 0.875% to 1.625%, depending on the amount outstanding under the credit facility.

Interest is payable at calendar quarters for base rate loans and at the earlier of maturity or three months from the date of the loan for fixed rate loans. In addition, the credit facility requires a commitment fee of:

- between 0.25% and 0.375% per annum on the unused portion of the designated borrowing base, and
- an additional fee equal to 33% of the commitment fee on the daily average amount by which the total amount of commitments exceeds the designated borrowing base.

The weighted average interest rate was 6.22%, 7.9% and 6.59%, respectively, for the years ended December 31, 2001, 2000 and 1999.

The credit facility contains covenants, including restrictions on liens and financial covenants which require us to, among other things, maintain:

- an interest coverage ratio of 2.5 to 1.0 of earnings before interest, taxes and depreciation to cash interest;
- a total debt to capitalization ratio of less than 60%, exclusive of non-cash charges; and
- sets a maximum limit of 70% on the amount of natural gas production we may hedge during any 12 month period.

In addition to maintenance of financial ratios, the credit facility restricts cash dividends and/or purchase or redemption of our stock. The credit facility also restricts the encumbering of our oil and gas assets or the pledging of those assets as collateral. As of December 31, 2001, we were in compliance with all covenants.

Senior Subordinated Notes

On March 2, 1998, we issued \$100 million of $8^5/_8$% senior subordinated notes due January 1, 2008. The notes bear interest at a rate of $8^5/_8$% per annum with interest payable semi-annually on January 1 and July 1. We may redeem the notes at our option, in whole or in part, at any time on or after January 1, 2003 at a price equal to 100% of the principal amount plus accrued and unpaid interest, if any, plus a specified premium if the notes are redeemed prior to January 1, 2006. Upon the occurrence of a change of control, we will be required to offer to purchase the notes at a purchase price equal to 101% of the aggregate principal amount, plus accrued and unpaid interest, if any. A "change of control" is:

- the direct or indirect acquisition by any person, other than KeySpan or its affiliates, of beneficial ownership of 35% or more of total voting power as long as KeySpan and its affiliates own less than the acquiring person;
- the sale, lease, transfer, conveyance or other disposition, other than by way of merger or consolidation, in one or a series of related transactions, of all or substantially all of our assets to a third party other than KeySpan or its affiliates;
- the adoption of a plan relating to our liquidation or dissolution; or
- if, during any period of two consecutive years, individuals who at the beginning of this period constituted our board of directors, including any new directors who were approved by a majority vote of the stockholders, cease for any reason to constitute a majority of the members then in office.

The notes are general unsecured obligations and rank subordinate in right of payment to all existing and future senior debt, including the credit facility, and will rank senior or equal in right of payment to all existing and future subordinated indebtedness.

NOTE 3 — Stockholders' Equity

KeySpan Credit Facility and Conversion

On November 30, 1998, we entered into a revolving credit facility with KeySpan, which provided a maximum commitment of $150 million. We borrowed $80 million under the credit facility to finance a portion of the November 1998 acquisition of the Mustang Island A-31 Field. On March 31, 2000, the outstanding borrowings of $80 million were converted into 5,085,177 shares of our common stock at a conversion price of $15.732 per share. As a result of the conversion, KeySpan's ownership interest in us increased from 64% at December 31, 1999 to 67% at December 31, 2001. The conversion price was determined based upon the average of the closing prices of our common stock, rounded to three decimal places, as reported under "NYSE Composite Transaction Reports" in the Wall Street Journal during the 20 consecutive trading days ending three trading days prior to March 31, 2000. The conversion of the KeySpan Facility and the corresponding issuance of additional shares of our common stock to KeySpan was approved by our stockholders at our annual meeting held April 27, 1999. Borrowings under the facility bore interest at LIBOR plus 1.4% and we incurred a quarterly commitment fee of 0.125% on the unused portion of the maximum commitment. The credit facility terminated on March 31, 2000. For the years ended December 31, 2000 and 1999, we incurred $1.5 million and $5.5 million, respectively, in interest and fees to KeySpan.

NOTE 4 — Stock Option Plans

1996 Stock Option Plan

The 1996 Stock Option Plan was adopted at the completion of our initial public offering in September 1996, and amended in 1997. The 1996 Plan limits the number of options authorized for grant to 10% of the outstanding shares of our common stock. The 1996 Plan allows us to grant both incentive stock options and non-qualified options. Options granted under the 1996 Stock Option Plan expire 10 years from the grant date and vest in one-fifth increments on each of the first five anniversaries of the grant date, with the exception of options granted to non-employee directors whose options vest immediately upon grant. As of December 31, 2001, approximately 14,509 options were authorized and available for grant under the 1996 Stock Option Plan. Since the plan's inception in 1996, a total of 3,027,203 options have been granted of which 1,532,890 were unexercised As of December 31, 2001. Of the options outstanding at December 31, 2001, 357,385 are incentive based options and the balance of 1,175,505 are non-qualified stock options. Common stock issued through the exercise of non-qualified options will result in a tax deduction for us, equivalent to the taxable gain recognized by the optionee. Generally, we will not receive an income tax deduction for incentive based options.

1999 Stock Option Plan

In October 1999, we adopted the 1999 Non-Qualified Stock Option Plan. Under the 1999 Stock Option Plan, a total of 800,000 options have been authorized of which 661,006 options have been granted and 631,058 are outstanding As of December 31, 2001. At December 31, 2001, the 1999 Stock Option Plan had 140,942 options available for grant. All options under the 1999 Stock Option Plan are non-qualified, expire 10 years from the grant date and vest in one-fifth increments on each of the first five anniversaries of the grant date, with the exception of options granted to non-employee directors which vest on the date of grant.

Phantom Stock Rights

1996 Phantom Stock Grant. In December 1996, we granted our key employees 176,470 phantom stock rights that give the holder the right to receive a cash payment determined by reference to the fair market value of one share of our common stock. Twenty percent (20%) of the phantom stock rights were payable on December 16th of each of the years 1997 through 2001. On each date on which a phantom stock right is payable, the holder received a cash payment equal to the average of the closing prices per share of our common stock for the five trading days immediately preceding the payment date multiplied by the number of phantom stock rights payable on the date. During 2001, 2000 and 1999, we made payments of $1.0 million, $1.0 million and $0.6 million, respectively for the vested portion of phantom stock rights. Payments made in December 2001 represented the final payments pursuant to the 1996 grant.

Incentive Compensation Plan for Non-Employee Directors. In October 1997, we adopted an incentive compensation plan for non-employee, non-affiliated directors under which they may defer current compensation in the form of phantom stock rights that are tied to the market price of the common stock on the date services are performed. Phantom stock rights are exchanged for a cash distribution upon retirement.

The table below sets forth a summary of activity during the respective years for both the 1996 and 1999 Stock Option Plans.

	Years Ended December 31,								
	2001			2000			1999		
	Shares		Price[(1)]	Shares		Price[(1)]	Shares		Price[(1)]
Options outstanding January 1	1,660,245	$	17.99	2,379,558	$	17.41	2,083,038	$	17.17
Granted	1,129,871		30.15	106,000		22.71	327,900		18.87
Exercised	(624,180)		16.32	(820,853)		16.93	(28,080)		15.56
Forfeited	(1,988)		29.02	(4,460)		18.83	(3,300)		18.56
Options outstanding December 31	2,163,948	$	24.81	1,660,245	$	17.99	2,379,558	$	17.41
Options exercisable December 31	940,929	$	21.83	721,654	$	17.43	1,001,343	$	16.87
Options available for grant December 31	155,451			682,698			286,638		

(1) Weighted average price. Grant price equal to closing market price on the NYSE on date of grant.

The table below sets forth a summary of options granted and outstanding, their remaining contractual lives, a weighted average exercise price and number vested and exercisable As of December 31, 2001.

December 31, 2001				
Options Outstanding	Remaining Contractual Life	Weighted Average Exercise Price Options Outstanding		Options Exercisable
168,269	5 years	$	15.54	168,269
219,060	6 years		20.03	166,640
261,696	7 years		19.06	167,676
282,980	8 years		18.85	185,720
103,100	9 years		22.65	41,100
1,128,843	10 years		30.15	211,524
2,163,948		$	24.81	940,929

Fair Value of Employee Stock-Based Compensation

We account for the incentive stock plans using the intrinsic value method prescribed under Accounting Principles Board No. 25 and accordingly we have not recognized compensation expense for stock options granted. Had stock options been accounted for using the fair value method as recommended in SFAS No. 123, compensation expense would have had the following pro forma effect on our net income and earnings per share for the years ended December 31, 2001, 2000 and 1999.

	Years Ended December 31,		
	2001	2000	1999
	(in thousands, except per share data)		
Net income - as reported	$122,601	$ 85,258	$ 24,621
Net income - pro forma	118,226	81,964	21,915
Net income per share - as reported	$ 4.06	$ 3.06	$ 1.03
Net income per share - assuming dilution - as reported	4.00	3.02	0.95
Net income per share - pro forma	$ 3.91	$ 2.94	$ 0.92
Net income per share - assuming dilution - pro forma	3.86	2.91	0.77

The effects of applying SFAS No. 123 in this pro forma disclosure may not be representative of future amounts. The weighted average fair values of options at their grant date during 2001, 2000 and 1999, where the exercise price equaled the market price on the grant date, were $13.45, $10.22 and $8.45, respectively. The fair value of each option grant was estimated on the date of grant using the Black-Scholes option pricing model with the following assumptions used for grants in 2001, 2000 and 1999:

	Years Ended December 31,		
	2001	2000	1999
Risk-free interest rate	5.80%	5.91%	5.96%
Expected years until exercise	5	5	5
Expected stock volatility	41%	41%	41%
Expected dividends	—	—	—

NOTE 5 — Income Taxes

The components of the federal income tax provision (benefit) are:

	Years Ended December 31,		
	2001	2000	1999
	(in thousands)		
Current	$ (840)	$ (818)	$ (961)
Deferred	67,643	43,303	12,709
Total	$ 66,803	$ 42,485	$ 11,748

The credit in the current provision primarily represents Section 29 tax credits (see Note 6—Related Party Transactions). As of December 31, 2001, 2000 and 1999, we had net operating loss carryforwards for federal income tax purposes of approximately $29 million, $34 million and $43 million, respectively, that may be used in future years to offset taxable income.

The following is a reconciliation of statutory federal income tax expense (benefit) to our income tax provision:

	Years Ended December 31,		
	2001	2000	1999
		(in thousands)	
Income before income taxes	$ 189,404	$ 127,743	$ 36,369
Statutory rate	35%	35%	35%
Income tax expense computed at statutory rate	66,291	44,710	12,729
Reconciling items:			
Section 29 tax credits and other tax credits[1]	512	(2,225)	(981)
Tax expense	$ 66,803	$ 42,485	$ 11,748

[1] Year ended 2001 includes an adjustment for an under-accrual of tax expense in 2000.

Deferred Income Taxes

The components of net deferred tax liabilities pursuant to SFAS No. 109 for the years ended December 31, 2001 and 2000 primarily represent temporary differences related to depreciation of natural gas and oil properties.

NOTE 6 — Related Party Transactions

Transactions With Keyspan

KeySpan Credit Facility and Conversion (See Note 3— Stockholders' Equity)

Review of Strategic Alternatives

In September 1999, we, along with KeySpan, our majority stockholder, announced our intention to review strategic alternatives for Houston Exploration and for KeySpan's investment in Houston Exploration. KeySpan was assessing the role of our company within its future strategic plan, and was considering a full range of strategic transactions including the sale of all or a portion of Houston Exploration. J.P. Morgan Securities Inc. was retained by KeySpan as financial advisor to assist in the strategic review on behalf of KeySpan. Our Board of Directors appointed a special committee comprised of outside directors to assist in the review process. We retained Goldman, Sachs and Co. as financial advisor. On February 25, 2000, together with KeySpan we jointly announced that the review of strategic alternatives had been completed and that KeySpan plans to retain its equity interest in us for the foreseeable future, however, KeySpan considers its investment in Houston Exploration a non-core asset. We incurred expenses relating to this review of strategic alternatives totaling $0.1 million during 2001 and $1.8 million during 2000.

KeySpan Joint Venture

Effective January 1, 1999, together with KeySpan, we entered into a joint exploration agreement with KeySpan Exploration & Production, LLC, a subsidiary of KeySpan, to explore for natural gas and oil over an initial two year term expiring December 31, 2000. Under the terms of the joint venture, we contributed all of our then undeveloped offshore acreage to the joint venture and KeySpan received 45% of our working interest in all prospects drilled under the program. KeySpan paid 100% of actual intangible drilling costs for the joint venture up to a specified maximum of $7.7 million in 2000 and $20.7 million during 1999 and KeySpan paid 51.75% of all additional intangible drilling costs incurred and we paid 48.25%. Revenues are shared 55% Houston Exploration and 45% to KeySpan. In addition, we received reimbursements from KeySpan for a portion of our general and administrative costs.

Effective December 31, 2000, KeySpan and Houston Exploration agreed to end the primary or exploratory term of the joint venture. As a result, KeySpan will not participate in any of our offshore exploration prospects unless the project involves the development or further exploitation of discoveries made during the initial term of the joint venture. In addition, effective with the termination of the exploratory term of the joint venture, we will not receive any reimbursement from KeySpan for general and administrative costs.

Since the beginning of our joint venture with KeySpan in January 1999, KeySpan has spent a total of $99.3 on exploration and development, with $ 17.2 million spent during 2001, $46.5 million spent during 2000 and $35.6 million spent during 1999. During the initial two-year exploratory term of the joint venture, we received from KeySpan a total of $7.3 million in general and administrative expense reimbursements, with $2.5 million paid during 2000 and $4.8 million paid during 1999. Reimbursement for general and administrative expenses terminated in 2000 with the expiration of the exploratory term of the joint venture.

During the initial two-year term of the joint drilling program, we drilled a total of 21 wells under the terms of the joint venture: 17 exploratory wells and four development wells. Five of the wells drilled were unsuccessful. During 2001, KeySpan participated in three additional wells, all of which were successful and further developed or delineated reservoirs discovered during the initial term of the joint venture. For 2002, KeySpan has committed to a capital budget of $15 million for development projects associated with its working interests in wells drilled under the joint venture during 1999, 2000 and 2001.

Sale of Section 29 Tax Credits

In January 1997, we entered into an agreement to sell to a subsidiary of KeySpan interests in our onshore producing wells that produce from formations that qualify for tax credits under Section 29 of the Internal Revenue Code Section 29 provides for a tax credit from non-conventional fuel sources such as oil produced from shale and tar sands and natural gas produced from geopressured brine, Devonian shale, coal seams and tight sands formations. KeySpan acquired an economic interest in wells that are qualified for the tax credits and in exchange, we:

- retained a volumetric production payment and a net profits interest of 100% in the properties,
- received a cash down payment of $1.4 million and
- receive a quarterly payment of $0.75 for every dollar of tax credit utilized.

We manage and administer the daily operations of the properties in exchange for an annual management fee of $100,000. The income statement effect, representing benefits received from Section 29 tax credits, was a benefit of $0.8 million, $0.9 million and 1.0 million, respectively, for each of the years ended December 31, 2001, 2000, and 1999.

Transactions With Our Executives

Restricted Stock Grant to New President and Chief Executive

On April 4, 2001, our Board of Directors appointed William G. Hargett to serve as our President and Chief Executive Officer and to serve on its Board of Directors. Pursuant to an employment agreement entered into on April 4, 2001 between us and Mr. Hargett, Mr. Hargett received a grant of 10,000 restricted shares of Houston Exploration common stock with a fair market value of approximately $256,000 at the time of grant. The stock is restricted from transfer and subject to forfeiture in the event Mr. Hargett's employment is terminated prior to April 4, 2004 and will otherwise vest, be nonforfeitable and freely transferable in equal one-third increments on each anniversary of the grant date. The cost of the restricted stock will be recognized in earnings as compensation expense over the stock's three year vesting period. During 2001, we recognized stock compensation expense of $64,000 related to this restricted stock grant.

Employment Contracts

We have entered into employment contracts with all seven of our executive officers. Contracts are initially set for a three year period and automatically extended one year on each anniversary unless either party gives notice within a specified number of days prior to the anniversary of the employment agreement. Executive officers receive annual salary and bonus payments pursuant to their employment contracts and if we terminate an employment agreement without cause or if the employee terminates an employment agreement with good reason, as defined in the employment agreements, we are obligated to pay the employee a lump-sum severance payment of 2.99 times the employee's then current annual rate of total compensation, as defined in the agreement, in addition to the continuation of welfare benefits for a specified time period.

Termination of Employment Agreements for Former Executives

Effective March 31, 2001, our President and Chief Executive Officer and Director, James G. Floyd, and our Senior Vice President - Exploration and Production, Randall J. Fleming, retired. Each had served in their respective positions since the Company's inception in 1986. In connection with their retirement as executive officers, each of Messrs. Floyd and Fleming agreed to the termination of their respective employment agreements. They received lump sum severance payments of $2.3 million and $1.4 million, respectively. Effective September 30, 2001, Thomas W. Powers, our Chief Financial Officer, left the Company to pursue other interests. In connection with the termination of his employment agreement with us, Mr. Powers received a lump sum severance payment of approximately $1.5 million. In total, the Company has incurred approximately $5.2 million in general and administrative expenses during 2001 as a result of the termination of employment contracts with former executives.

Transactions with Former President and Chief Executive Officer

Prior to our initial public offering in September 1996, we were party to an employment agreement with our former President and Chief Executive Officer, Mr. Floyd. Under this employment agreement, we had:

- granted Mr. Floyd an option to obtain up to a 5% working interest in specified exploration prospects, exercisable at the time of acquisition of the prospect or prior to the commencement of drilling of the initial well on any of the prospects;
- assigned to Mr. Floyd a 2% net profits interest in all exploration prospects at the time the properties were acquired;
- assigned to key employees designated by Mr. Floyd overriding royalty interests equivalent to a 4% net revenue interest in specified properties at the time we acquired the properties; and
- assigned to Mr. Floyd a 6.75% after program-payout working interest in the leases upon which we began drilling an exploratory well (whether or not successful) during a calendar year.

Mr. Floyd and his affiliates opted to acquire a 5% working interest in the Charco Field properties we acquired in July 1996 and the right to participate with a 5% working interest in any future wells we drilled in the Charco Field. We loaned to Mr. Floyd the $3.1 million purchase price for the purchase of a 5% working interest in the Charco Field properties. In addition, we agreed to loan to Mr. Floyd, on a revolving basis, the amounts required to fund the expenses attributable to his working interest. Mr. Floyd was required to repay amounts owed under the loan in the amount of 65% of all distributions received in respect to the working interest, as distributions are received. Amounts outstanding under the loan accrued interest at an interest rate equal to our cost of borrowing under our credit facility. Obligations under the agreement were secured by a pledge of Mr. Floyd's working interest in, and the production from, the properties. As of December 31, 2000, the outstanding balance owed by Mr. Floyd under the loan was $0.6 million. Mr. Floyd repaid the loan in full as of February 28, 2001.

No assignments were made to Mr. Floyd or to key employees subsequent to 1995 and upon completion of our initial public offering in September 1996, Mr. Floyd's employment agreement was replaced with a new employment agreement which did not provide Mr. Floyd with the option to participate in our prospects as a working interest owner or to receive or grant assignments or after program-payout working interests; however, due to the nature of an overriding royalty interest, Mr. Floyd and any employees receiving assignments will continue to receive payments pursuant to their overriding interest until production from the related property ends.

In January 2000, we agreed to exchange all of the working interests and net profits interests Mr. Floyd had acquired in our properties pursuant to the initial employment agreement for an overriding royalty interest in those same properties. The exchange, was effective October 1, 1999, and was structured such that the net present value we would earn and that Mr. Floyd would earn would be approximately the same regardless of the nature of Mr. Floyd's participation in the earnings from the properties. As of October 1, 1999, the net present value, discounted at 10%, of the properties exchanged was approximately $13.5 million.

During 2001 and 2000, Mr. Floyd received $6.9 million and $5.4 million (net of $0.4 million in related expenses), respectively, relating to his overriding royalty interests in our properties. During 1999, Mr. Floyd and his affiliates received $4.7 million in revenues attributable to his previously held working interests and net profits interests in our properties and paid $2.5 million in costs and expenses attributable to those properties.

NOTE 7 — Employee Benefit Plans

401(k) Profit Sharing Plan

We maintain a 401(k) Profit Sharing Plan for our employees. Under the 401(k) plan, eligible employees may elect to have us contribute on their behalf up to 12.5% of their base compensation (subject to limitations imposed under the Internal Revenue Code of 1986, as amended) on a before tax basis. We make a matching contribution of $1.00 for each $1.00 of employee deferral, subject to limitations imposed by the 401(k) plan and the Internal Revenue Service. The amounts contributed under the 401(k) plan are held in a trust and invested among various investment funds, including the Company's common stock, in accordance with the directions of each participant. An employee's salary deferral contributions under the 401(k) plan are 100% vested. Our matching contributions vest at the rate of 20% per year of service. Participants are entitled to payment of their vested account balances upon termination of employment. We made contributions to the 401(k) plan of $0.7 million, $0.6 million and $0.3 million, respectively, for the years ended December 31, 2001, 2000 and 1999.

Supplemental Executive Retirement Plan

We maintain an unfunded, non-qualified Supplemental Executive Retirement Plan. Currently, the only beneficiary is our former President and Chief Executive Officer, James G. Floyd. Upon Mr. Floyd's retirement March 31, 2001, he is entitled to receive payment of $100,000 per year for life. If Mr. Floyd predeceases his spouse, 50% of his retirement plan benefit will continue to be paid to his surviving spouse for her life. We incurred expenses of approximately $113,000, $123,000 and $123,000, respectively, during the years ended December 31, 2001, 2000 and 1999 related to this retirement plan.

NOTE 8 — Hedging Contracts

Natural Gas Price Swaps, Options and Collars

As of December 31, 2001, we had entered into commodity price hedging contracts with respect to our production for 2002 and 2003 as listed in the table below. Volumes and fair values are stated in thousands.

	Fixed Price Swaps		Collars			Fair Value
Period	Volume (MMbtu)	NYMEX Contract Price	Volume (MMbtu)	NYMEX Contract Price Avg Floor	Avg Ceiling	($ thousands)
January 2002	930	$3.010	4,340	$3.643	$5.356	$5,144
February 2002	840	3.010	3,920	3.643	5.356	4,585
March 2002	930	3.010	4,340	3.643	5.356	5,176
April 2002	900	3.010	4,200	3.643	5.356	5,054
May 2002	930	3.010	4,340	3.643	5.356	5,041
June 2002	900	3.010	4,200	3.643	5.356	4,654
July 2002	930	3.010	4,340	3.643	5.356	4,655
August 2002	930	3.010	4,340	3.643	5.356	4,497
September 2002	900	3.010	4,200	3.643	5.356	4,352
October 2002	930	3.010	4,340	3.643	5.356	4,385
November 2002	900	3.010	4,200	3.643	5.356	3,424
December 2002	930	3.010	4,200	3.643	5.356	2,690
January 2003	1,240	$3.194	—	—	—	10
February 2003	1,120	3.194	—	—	—	9
March 2003	1,240	3.194	—	—	—	10
April 2003	1,200	3.194	—	—	—	9
May 2003	1,240	3.194	—	—	—	10
June 2003	1,200	3.194	—	—	—	9
July 2003	1,240	3.194	—	—	—	10
August 2003	1,240	3.194	—	—	—	10
September 2003	1,200	3.194	—	—	—	9
October 2003	1,240	3.194	—	—	—	9
November 2003	1,200	3.194	—	—	—	9
December 2003	1,240	3.194	—	—	—	10
						$53,771

At December 31, 2001, the fair market value of our derivative instruments was an asset of $53.8 million. Fair market value is calculated for the respective months using prices derived from NYMEX futures contract prices existing at December 31, 2001 and from market quotes received from counterparties.

These hedging transactions are settled based upon the average of the reported settlement prices on the NYMEX for the last three trading days of a particular contract month or the NYMEX price on the final trading day of the month (the "settlement price"). With respect to any particular swap transaction, the counterparty is required to make a payment to us in the event that the settlement price for any settlement period is less than the swap price for the transaction, and we are required to make payment to the counterparty in the event that the settlement price for any settlement period is greater than the swap price for the transaction. For any particular collar transaction (excluding the no-cost collars with floating floors discussed above), the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price for the transaction, and we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price for the transaction. We are not required to make or receive any payment in connection with a collar transaction if the settlement price is between the floor and the ceiling.

As of December 31, 2000, we had entered into commodity price hedging contracts with respect to our production for 2001 as follows:

	Fixed Price Swaps		Collars			Fair Value
Period	Volume (MMbtu)	NYMEX Contract Price	Volume (MMbtu)	NYMEX Contract Avg Floor	Price Avg Ceiling	($ thousands)
January 2001	—	$—	4,960	$ 3.63	$ 5.30	$ (23,208)
February 2001	—	—	4,480	3.63	5.30	(20,052)
March 2001	—	—	4,960	3.63	5.30	(17,524)
April 2001	—	—	4,800	4.00	6.11	(2,981)
May 2001	—	—	4,960	4.00	6.11	(1,303)
June 2001	—	—	4,800	4.00	6.11	(1,221)
July 2001	—	—	4,960	4.00	6.11	(1,341)
August 2001	—	—	4,960	4.00	6.11	(1,386)
September 2001	—	—	4,800	4.00	6.11	(1,350)
October 2001	—	—	4,960	4.00	6.11	(1,491)
November 2001	—	—	4,800	4.00	6.37	(1,419)
December 2001	—	—	4,960	4.00	6.37	(1,793)
						$ (75,069)

At December 31, 2000, the fair market value of our derivative instruments was a liability of $75 million. Fair market value is calculated for the respective months using prices derived from NYMEX futures contract prices existing at December 31, 2000 and from market quotes received from counterparties.

NOTE 9 — Sales To Major Customers

We sold natural gas and oil production representing 10% or more of our natural gas and oil revenues for the years ended December 31, 2001, 2000 and 1999 as listed below. In the exploration, development and production business, production is normally sold to relatively few customers. However, based on the current demand for natural gas and oil, we believe that the loss of any of our major purchasers would not have a material adverse effect on our operations.

	For the Year Ended December 31,		
Major Purchaser	2001	2000	1999
Dynegy Inc.	16.4%	22.5%	18.0%
Adams Resources and Energy, Inc	12.5%	14.9%	22.5%
El Paso Corporation(1)	9.5%	9.1%	7.7%

(1) Amount purchased was less than 10% of our natural gas and oil sales revenues, and is included for information purposes only.

NOTE 10 — Commitments and Contingencies

Litigation

We are involved from time to time in various claims and lawsuits incidental to our business. In the opinion of management, the ultimate liability, if any, will not have a material adverse effect on our financial position or results of operations.

Leases

We have entered into noncancellable operating lease agreements relative to the lease of our office space at 1100 Louisiana in Houston, Texas and various types of office equipment (telephones, copiers and fax machines) with various expiration dates through 2009. Minimum rental commitments under the terms of our operating leases are as follows (in thousands):

Year Ended December 31,	Minimum Payments
2002	$ 942
2003	1,044
2004	1,094
2005	1,139
2006	1,113
Thereafter	3,326

Net rental expense related to these leases was $0.6 million, $0.5 million and $0.5 million, respectively, for the years ended December 31, 2001, 2000 and 1999.

NOTE 11 — Acquisitions

Conoco Acquisition

On December 31, 2001, we completed the purchase of certain natural gas and oil properties and associated gathering pipelines and equipment, together with developed and undeveloped acreage, located in Webb and Zapata counties of South Texas, from Conoco Inc. The $69 million purchase price was paid in cash and financed by borrowings under our revolving bank credit facility. The properties purchased cover approximately 25,274 gross (16,885 net) acres located in the Alexander, Haynes, Hubbard and South Trevino Fields, which are in close proximity to our existing operations in the Charco Field, and represent interests in approximately 159 producing wells. We operate approximately 95% of the producing wells acquired and our average working interest is 87%. With this acquisition, we have expanded and will improve our operations in South Texas which has been an area of strategic growth for us over the last five years. During February 2002, the properties we acquired produced approximately 19.0 MMcfe per day, net to our interests.

NOTE 12— Supplemental Information On Natural Gas and Oil Exploration, Development and Production Activities (Unaudited)

The following information concerning our natural gas and oil operations has been provided pursuant to Statement of Financial Accounting Standards No. 69, "Disclosures about Oil and Gas Producing Activities." Our natural gas and oil producing activities are conducted onshore within the continental United States and offshore in federal and state waters of the Gulf of Mexico. Our natural gas and oil reserves were estimated by independent reserve engineers.

Capitalized Costs of Natural Gas and Oil Properties

As of December 31, 2001, 2000 and 1999, our capitalized costs of natural gas and oil properties are as follows:

	As of December 31,		
	2001	2000	1999
		(in thousands)	
Unevaluated properties, not amortized	$ 177,987	$ 142,890	$ 164,377
Properties subject to amortization	1,493,293	1,162,000	956,484
Capitalized costs	1,671,280	1,304,890	1,120,861
Accumulated depreciation, depletion and amortization	(735,257)	(601,034)	(512,465)
Net capitalized costs	$ 936,023	$ 703,856	$ 608,396

Unevaluated Cost Additions

The following is a summary of the costs (in thousands) which are excluded from the amortization calculation As of December 31, 2001, by year of acquisition. We are not able to accurately predict when these costs will be included in the amortization base; however, we believe that unevaluated properties at December 31, 2001 will be fully evaluated within five years.

Year Incurred	Unevaluated Costs
2001	$ 72,522
2000	20,325
1999	16,957
Prior	68,183
	$ 177,987

Capitalized Costs Incurred

Costs incurred for natural gas and oil exploration, development and acquisition are summarized below. Costs incurred during the years ended December 31, 2001, 2000 and 1999 include interest expense and general and administrative costs related to acquisition, exploration and development of natural gas and oil properties, of $24.9 million, $23.3 million and $17.4 million, respectively.

	As of December 31,		
	2001	2000	1999
		(in thousands)	
Property acquisition:			
Unevaluated(1)	$ 31,711	$ 7,955	$ 10,337
Proved	85,367	38,579	37,105
Exploration costs	72,056	37,162	12,257
Development costs	177,256	100,333	87,965
Total costs incurred	$ 366,390	$ 184,029	$ 147,664

(1) These amounts represent costs we incurred and excluded from the amortization base until proved reserves are established or impairment is determined.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Natural Gas and Oil Reserves (unaudited)

The following summarizes the policies we used in the preparation of the accompanying natural gas and oil reserve disclosures, standardized measures of discounted future net cash flows from proved natural gas and oil reserves and the reconciliations of standardized measures from year to year. The information disclosed, as prescribed by the Statement of Financial Accounting Standards No. 69 is an attempt to present the information in a manner comparable with industry peers.

The information is based on estimates of proved reserves attributable to our interest in natural gas and oil properties as of December 31 of the years presented. These estimates were principally prepared by independent petroleum consultants. Proved reserves are estimated quantities of natural gas and crude oil 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 standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

1. Estimates are made of quantities of proved reserves and future periods during which they are expected to be produced based on year-end economic conditions.
2. The estimated future cash flows are compiled by applying year-end prices of natural gas and oil relating to our proved reserves to the year-end quantities of those reserves.
3. The future cash flows are reduced by estimated production costs, costs to develop and produce the proved reserves and abandonment costs, all based on year-end economic conditions.
4. Future income tax expenses are based on year-end statutory tax rates giving effect to the remaining tax basis in the natural gas and oil properties, other deductions, credits and allowances relating to our proved natural gas and oil reserves.
5. Future net cash flows are discounted to present value by applying a discount rate of 10 percent.

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of our natural gas and oil reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves is as follows and does not include cash flows associated with hedges outstanding at each of the respective reporting dates:

	As of December 31,		
	2001	2000	1999
		(in thousands)	
Future cash inflows	$ 1,471,557	$ 5,189,328	$ 1,113,844
Future production costs	(302,145)	(542,139)	(190,900)
Future development costs	(189,480)	(153,210)	(120,071)
Future income taxes	(211,191)	(1,250,272)	(155,641)
Future net cash flows	768,741	3,243,707	647,232
10% annual discount for estimated timing of cash flows	(217,216)	(1,179,680)	(178,007)
Standardized measure of discounted future net cash flows	$ 551,525	$ 2,064,027	$ 469,225

The following table summarizes changes in the standardized measure of discounted future net cash flows:

	As of December 31,		
	2001	2000	1999
		(in thousands)	
Beginning of the year	$ 2,064,027	$ 469,225	$ 396,060
Revisions to previous estimates:			
Changes in prices and costs	(2,088,576)	2,163,984	47,330
Changes in quantities	(52,928)	24,650	51,375
Changes in future development costs	(18,001)	(32,152)	(25,730)
Development costs incurred during the period	65,940	57,046	40,563
Extensions and discoveries, net of related costs	116,710	403,012	91,383
Sales of natural gas and oil, net of production costs	(343,181)	(237,286)	(126,730)
Accretion of discount	279,648	52,967	41,293
Net change in income taxes	635,400	(672,005)	(43,572)
Purchase of reserves in place	51,674	23,118	20,973
Sale of reserves in place	(133)	—	(2,194)
Production timing and other	(159,055)	(188,532)	(21,526)
End of year	$ 551,525	$ 2,064,027	$ 469,225

Estimated Net Quantities of Natural Gas and Oil Reserves (Unaudited)

The following table sets forth our net proved reserves, including changes, and proved developed reserves (all within the United States) at the end of each of the three years in the period ended December 31, 2001, 2000 and 1999.

	Natural Gas (MMcf)			Crude Oil and Condensate (MBbls)		
	2001	2000	1999	2001	2000	1999
Proved developed and undeveloped reserves:	529,518	526,185	470,447	5,352	2,470	1,650
Revisions of previous estimates	(41,914)	3,709	45,510	(174)	107	237
Extensions and discoveries	83,551	69,564	62,700	1,800	2,424	909
Production	(87,095)	(77,861)	(69,679)	(459)	(311)	(258)
Purchase of reserves in place	84,148	7,921	20,699	115	662	1
Sales of reserves in place	—	—	(3,492)	(29)	—	(69)
End of year	568,208	529,518	526,185	6,605	5,352	2,470
Proved developed reserves:						
Beginning of year	420,733	397,343	369,931	1,810	1,796	1,498
End of year	438,538	420,733	397,343	2,123	1,810	1,796

NOTE 13— Quarterly Financial Information (Unaudited)

Selected unaudited quarterly data is shown below:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(in thousands, except per share data)			
2001				
Total revenues	$ 124,342	$ 99,308	$ 78,495	$ 78,712
Income from operations	75,199	56,876	34,394	26,046
Net income	47,344	35,855	22,530	16,872
Net income per share[(1)]	$ 1.58	$ 1.19	$ 0.74	$ 0.55
Net income per share—assuming dilution[(1)]	$ 1.55	$ 1.17	$ 0.73	$ 0.55
2000				
Total revenues	$ 49,348	$ 57,930	$ 62,903	$102,152
Income from operations	18,419	27,301	32,479	62,657
Net income	8,449	16,328	19,666	40,815
Net income per share[(1)]	$ 0.35	$ 0.56	$ 0.67	$ 1.40
Net income per share—assuming dilution[(1)]	$ 0.35	$ 0.56	$ 0.66	$ 1.38

(1) Quarterly earnings per share is based on the weighted average number of shares outstanding during the quarter. Because of the increase in the number of shares outstanding during the quarters due to the exercise of stock options or the issuance of common stock (see Note 3—Stockholders' Equity), the sum of quarterly earnings per share do not equal earnings per share for the year.

INDEX TO EXHIBITS

EXHIBITS		DESCRIPTION
3.1	—	Restated Certificate of Incorporation (filed as Exhibit 3.1 to our Quarterly Report on Form 10- Q for the quarterly period ended June 30, 1997 (File No. 001-11899) and incorporated by reference).
3.2	—	Restated Bylaws (filed as Exhibit 3.2 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1997 (File No. 001-11899) and incorporated by reference).
4.1	—	Indenture, dated as of March 2, 1998, between The Houston Exploration Company and The Bank of New York, as Trustee, with respect to the $8^5/_8$% Senior Subordinated Notes Due 2008 (including form of $8^5/_8$% Senior Subordinated Note Due 2008) (incorporated by reference to Exhibit 4.1 to our Registration Statement on Form S-4 (No. 333-50235)).
10.1[(2)]	—	Employment Agreement dated July 2, 1996 between The Houston Exploration Company and James G. Floyd (filed as Exhibit 10.8 to our Registration Statement on Form S-1 (Registration No. 333-4437) and incorporated by reference).
10.2[(2)]	—	Employment Agreement dated July 2, 1996 between The Houston Exploration Company and Randall J. Fleming (filed as Exhibit 10.9 to our Registration Statement on Form S-1 (Registration No. 333-4437) and incorporated by reference).
10.3[(2)]	—	Employment Agreement dated July 2, 1996 between The Houston Exploration Company and Thomas W. Powers (filed as Exhibit 10.10 to our Registration Statement on Form S-1 (Registration No. 333-4437) and incorporated by reference).
10.4[(2)]	—	Employment Agreement dated July 2, 1996 between The Houston Exploration Company and James F. Westmoreland (filed as Exhibit 10.11 to our Registration Statement on Form S-1 (Registration No. 333-4437) and incorporated by reference).
10.5	—	Registration Rights Agreement dated as of July 2, 1996 between The Houston Exploration Company and THEC Holdings Corp. (filed as Exhibit 10.13 to our Registration Statement on Form S-1 (Registration No. 333-4437) and incorporated by reference).
10.6	—	Registration Rights Agreement between The Houston Exploration Company and Smith Offshore Exploration Company (filed as Exhibit 10.15 to our Registration Statement on Form S-1 (Registration No. 333-4437) and incorporated by reference).
10.7[(2)]	—	Registration Rights Agreement dated as of September 25, 1996 between The Houston Exploration Company and James G. Floyd (filed as Exhibit 10.22 to our Registration Statement on Form S-1 (Registration No. 333-4437) and incorporated by reference).
10.8[(2)]	—	Supplemental Executive Pension Plan (filed as Exhibit 10.23 to our Registration Statement on Form S-1 (Registration No. 333-4437) and incorporated by reference).
10.9[(2)]	—	Employment Agreement, dated September 19, 1996, between The Houston Exploration Company and Charles W. Adcock (filed as Exhibit 10.26 to our Annual Report on Form 10-K for the year ended December 31, 1996 (File No. 001-11899) and incorporated by reference).
10.10[(2)]	—	Form of Letter Agreement from The Houston Exploration Company to each of James G. Floyd, Randall J. Fleming, Thomas W. Powers, Charles W. Adcock, James F. Westmoreland and Sammye L. Dees evidencing grants of Phantom Stock Rights effective as of December 16, 1996 (filed as Exhibit 10.27 to our Annual Report on Form 10-K for the year ended December 31, 1996 (File No. 001-11899) and incorporated by reference).
10.11[(2)]	—	Deferred Compensation Plan for Non-Employee Directors (filed as Exhibit 10.24 to our Annual Report on Form 10-K for the year ended December 31, 1997 (File No. 001-11899) and incorporated by reference).
10.12	—	Amended and Restated 1996 Stock Option Plan (filed as Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 1998 (File No. 001-11899) and incorporated by reference).
10.13[(2)]	—	Employment Agreement dated May 1, 1998 between The Houston Exploration Company and Thomas E. Schwartz (filed as Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 1998 (File No. 001-11899) and incorporated by reference).

INDEX TO EXHIBITS

EXHIBITS		DESCRIPTION
10.14	—	Subordinated Loan Agreement dated November 30, 1998 between The Houston Exploration Company and MarketSpan Corporation d/b/a KeySpan Energy Corporation (filed as Exhibit 10.30 to our Annual Report on Form 10-K for the year ended December 31, 1998 and incorporated by reference).
10.15	—	Subordination Agreement dated November 25, 1998 entered into and among MarketSpan Corporation d/b/a KeySpan Energy Corporation, The Houston Exploration Company and Chase Bank of Texas, National Association (filed as Exhibit 10.31 to our Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 001-11899) and incorporated by reference).
10.16	—	First Amendment to Subordinated Loan Agreement and Promissory Note between KeySpan Corporation and The Houston Exploration Company dated effective as of October 27, 1999 (filed as Exhibit 10.17 to our Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 001-11899) and incorporated by reference).
10.17	—	Exploration Agreement between The Houston Exploration Company and KeySpan Exploration and Production, L.L.C., dated March 15,1999, (filed as Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 1999 (File No. 001-11899) and incorporated by reference).
10.18	—	First Amendment to the Exploration Agreement between The Houston Exploration Company and KeySpan Exploration and Production, L.L.C. dated November 3, 1999 (filed as Exhibit 10.19 to our Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 001-11899) and incorporated by reference).
10.19	—	Amended and Restated Credit Agreement among The Houston Exploration Company and Chase Bank of Texas, National Association, as agent, dated March 30,1999, (filed as Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 1999 (File No. 001-11899) and incorporated by reference).
10.2	—	First Amendment and Supplement to Amended and Restated Credit Agreement dated May 4, 1999 by and among The Houston Exploration Company and Chase Bank of Texas, National Association, as agent, (filed as Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 1999 (File No. 001-11899) and incorporated by reference).
10.21	—	Second Amendment to Amended and Restated Credit Agreement between The Houston Exploration Company and Chase Bank of Texas, National Association, as agent, dated October 6, 1999, (filed as Exhibit 10.32 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 1999 (File No. 001-11899) and incorporated by reference).
10.22	—	Third Amendment and Supplement to Amended and Restated Credit Agreement between The Houston Exploration Company and Chase Bank of Texas, National Association, as agent, dated December 9, 1999 (filed as Exhibit 10.23 to our Annual Report on Form 10-K for the year ended December 31, 1999 File No. 001-11899) and incorporated by reference).
10.23(2)	—	1999 Non-Qualified Stock Option Plan dated October 26, 1999 (filed as Exhibit 10.24 to our Annual Report on Form 10-K for the year ended December 31, 1999 File No. 001-11899) and incorporated by reference).
10.24(2)	—	Change of Control Plan dated October 26, 1999 (filed as Exhibit 10.25 to our Annual Report on Form 10-K for the year ended December 31, 1999 File No. 001-11899) and incorporated by reference).
10.25(2)	—	Restated Exploration Agreement dated June 30, 2000 between The Houston Exploration Company and KeySpan Exploration and Production, L.L.C (filed as Exhibit 10.1 to our Quarterly on Form 10-Q for the quarter ended September 30, 2000 File No. 001-11899) and incorporated by reference).
10.26(2)	—	First Amendment to Employment Agreement dated March 8, 2001 between The Houston Exploration Company and Thomas W. Powers (filed as Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2001 File No. 001-11899).
10.27(2)	—	Employment Agreement dated April 4, 2001 between The Houston Exploration Company and William G. Hargett (filed as Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2001 File No. 001-11899).

INDEX TO EXHIBITS

EXHIBITS	DESCRIPTION
10.28[2] —	First Amendment to Employment Agreement dated April 26, 2001 between The Houston Exploration Company and Charles W. Adcock (filed as Exhibit 10.3 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2001 File No. 001-11899).
10.29[2] —	First Amendment to Employment Agreement dated April 26, 2001 between The Houston Exploration Company and Thomas W. Schwartz (filed as Exhibit 10.4 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2001 File No. 001-11899)
10.30[2] —	First Amendment to Employment Agreement dated April 26, 2001 between The Houston Exploration Company and James F. Westmoreland (filed as Exhibit 10.5 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2001 File No. 001-11899).
10.31[2] —	Employment Agreement dated July 16, 2001 between The Houston Exploration Company and Tracy Price (filed as Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2001 File No. 001-11899).
10.32[1][2] —	Employment Agreement dated October 22, 2001 between The Houston Exploration Company and Steven L. Mueller.
10.33[1][2] —	Employment Agreement dated March 1, 2002 between The Houston Exploration Company and Roger B. Rice.
12.1[1] —	Computation of ratio of earnings to fixed charges.
21.1[1] —	Subsidiaries of Houston Exploration.
23.1[1] —	Consent of Arthur Andersen LLP.
23.2[1] —	Consent of Netherland, Sewell & Associates.
23.3[1] —	Consent of Miller and Lents.

(1) Filed herewith.

(2) Management contract or compensation plan.

Exhibit 12.1

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

	For the Years Ended December 31,				
	2001	2000	1999	1998	1997
	(in thousands)				
Fixed Charges:					
Gross interest expense	$ 15,034	$ 25,100	$ 25,167	$ 14,414	$ 6,811
Interest portion of rent expense	46	40	28	39	32
	15,080	25,140	25,195	14,453	6,843
Earnings:					
Income (loss) before taxes	189,404	127,743	36,369	(113,440)	33,423
Plus: fixed charges	15,080	25,140	25,195	14,453	6,843
Less: capitalized interest	(12,042)	(13,739)	(11,860)	(9,817)	(5,873)
	$ 192,442	$ 139,144	$ 49,704	$(108,804)	$ 34,393
Ratio of Earnings to Fixed Charges	12.8x	5.5x	2.0x	N/M	5.0x

THE HOUSTON EXPLORATION COMPANY

Corporate *Information*

The Houston Exploration Company common stock is listed on the New York Stock Exchange (symbol THX). At March 25, 2002, the Company's shares of common stock outstanding were held by approximately 40 shareholders of record and 3,100 beneficial owners.

CORPORATE OFFICES

The Houston Exploration Company
1100 Louisiana
Suite 2000
Houston, Texas 77002-5219
(713) 830-6800
www.houstonexploration.com

ANNUAL MEETING

The Houston Exploration Company will hold its Annual Meeting of Shareholders on Friday, May 17, 2002 at 10 am at
The DoubleTree Hotel
Allen Center
400 Dallas Street
Houston, Texas.

FORM 10-K REQUESTS

Shareholders interested in obtaining, without cost, a copy of the Form 10-K filed by the company with the Securities and Exchange Commission may do so by writing to the Corporate Secretary, at the company address.

INVESTOR RELATIONS

Shareholders, brokers, securities analysts or portfolio managers seeking information about the company are welcome to contact Kerry Thornhill-Houston, Director of Investor Relations and Corporate Communications, at (713) 830-6887.

INDEPENDENT PUBLIC ACCOUNTANTS

Arthur Andersen LLP
1345 Avenue of the Americas
New York, NY 10105

Communications concerning the transfer of shares, lost certificates, duplicate mailings or change of address should be directed to the stock transfer agent.

STOCK TRANSFER AGENT AND REGISTRAR

The Bank of New York
1-800-524-4458

Address Shareholder Inquiries to:
Shareholder Relations Department – 11E
P.O. Box 11258
Church Street Station
New York, NY 10286

E-Mail Address:
Shareowner-svcs@bankofny.com

The Bank of New York's Stock Transfer Website:
http://www.stock.bankofny.com

Send Certificates for Transfer and Address Changes to:
Receive and Deliver Department – 11W
P.O. Box 11002
Church Street Station
New York, NY 10286

STOCK DATA

	CLOSING PRICES HIGH	LOW
2001		
First Quarter	$38.90	$28.10
Second Quarter	$36.47	$25.58
Third Quarter	$33.76	$22.50
Fourth Quarter	$34.49	$23.50
2000		
First Quarter	$20.37	$15.00
Second Quarter	$25.50	$17.56
Third Quarter	$27.33	$21.50
Fourth Quarter	$39.37	$22.50

THX Listed NYSE THE NEW YORK STOCK EXCHANGE

DESIGN: CREGAN DESIGN; PHOTOGRAPHY: KENNY BRAUN, DREW DONOVAN, JAY RUSOVICH

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