HOUSTON EXPLORATION CO
Form 10-K
February 23, 2005

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

FORM 10-K

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

For the fiscal year ended December 31, 2004
OR
o 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 7% Senior Subordinated Notes due 2013	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 þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. Yes þ No o

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

The aggregate market value of the voting stock held by non-affiliates of the registrant was approximately $1,112,109,212, based on the closing sales price of $51.84 per share of the registrant s common stock as reported by on the New York Stock Exchange as of June 30, 2004, the last business day of the registrant s most recently completed second fiscal quarter. For purposes of the preceding sentence only, all directors, executive officers and beneficial owners of ten percent or more of the common stock are assumed to be affiliates. As of February 22, 2005, 28,457,804 shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant s Proxy Statement for the Annual Meeting of Stockholders to be held April 26, 2005 are incorporated by reference into Part III of this Form 10-K.

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Forward-Looking Statements and Other Information

This Annual Report on Form 10-K (Annual Report) and the documents we have incorporated by reference into this Annual Report contain forward-looking statements as that term is defined in Section 27A of the Securities Act of 1933, as amended (the Securities Act) and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). These statements use forward-looking words such as anticipate, believe, continue, expect, esti intend, may, plan, potential, predict, project, should, target, goal, objective or other similar expres forward-looking information. Forward-looking statements include all statements under the caption Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations involving the discussion of the following:

- business strategy;
- natural gas and oil reserves;
- future production;
- expected realized natural gas and oil prices;
- expected costs and expenses;
- anticipated capital expenditures;
- future operating results;
- future cash flows and borrowings;
- pursuit of potential future acquisition opportunities;
- identified drilling locations; and
- sources of funding and the timing of exploration and development activities.

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 those anticipated or implied in the forward-looking statements. These factors include, among other things:

- the volatility of natural gas and oil prices;
- the requirement to take writedowns if natural gas and oil prices decline or if our finding and development costs continue to increase;
- the relatively short production lives of our reserves;
- our ability to find, replace, develop and acquire natural gas and oil reserves;
- maturity of North American gas basins;
- acquisition and investment risks;

our ability to meet our substantial capital requirements;

our outstanding indebtedness;

the uncertainty of estimates of natural gas and oil reserves and production rates;

the inherent hazards and risks involved in our operations;

dependence upon operations concentrated in three primary areas;

drilling risks;

our hedging activities;

compliance with environmental and other governmental regulations;

the competitive nature of our industry;

weather risks and other natural disasters; and

our customers ability to meet their obligations.

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For additional discussion of these and other 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. We undertake no obligation to publicly update or revise any forward-looking statements.

In this Annual Report, unless the context requires otherwise, when we refer to we, us and our, we are describing The Houston Exploration Company and our former sole subsidiary on a consolidated basis.

If you are not familiar with the natural gas and oil terms used in this Annual Report, please refer to the explanations of the terms under the caption Glossary of Natural Gas and Oil Terms included on pages G-1 through G-2. 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.

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Part I.

Items 1. and 2. Business and Properties

Overview of Our Business

We are an independent natural gas and oil producer concentrating on growing reserves and production through the exploration, development, exploitation and acquisition of natural gas and oil reserves in North America. Approximately 94% of our proved reserves as of December 31, 2004 were natural gas. Our principal operations are located in the following areas:

South Texas, where we are one of the largest natural gas producers along the prolific Lobo Trend in Zapata, Webb and Jim Hogg Counties;

Offshore in the Gulf of Mexico, where we pursue a range of activities with exploration targeting predominantly deep shelf prospects below 15,000 feet on the Outer Continental Shelf and exploitation focusing on development opportunities intended to increase production from acquired properties;

Arkoma Basin, of Arkansas and Oklahoma, where we have doubled production since the end of 2002 through an active in-field drilling program enabled by a series of successful, field-wide downspacing initiatives; and

Rocky Mountains, where we commenced an aggressive lease acquisition campaign in 2003, with an initial focus in the Uinta Basin of Northeastern Utah and the DJ Basin in Eastern Colorado, and where we currently are conducting exploration programs to test several prospective natural gas fields.

At December 31, 2004, net proved reserves were 793 billion cubic feet equivalent or Bcfe, with a standardized measure of future net cash flows including income taxes, discounted at 10% per annum, of $1.4 billion. Our reserves are fully engineered on an annual basis by independent petroleum engineers. Approximately 63% of our proved reserves at December 31, 2004, were classified as proved developed. As of December 31, 2004, we operated approximately 77% of our producing wells. Daily production averaged 339 million cubic feet of natural gas equivalent or MMcfe in 2004.

We were founded in December 1985 as a Delaware corporation and began exploring for natural gas and oil on behalf 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 and sold approximately 31% of our shares to the public. Through three separate transactions, the first in February 2003 and last in November 2004, KeySpan completely divested of its investment in the common stock of our company. As of December 31, 2004, KeySpan no longer owned any common stock of our company.

Our corporate offices are located at 1100 Louisiana Street, Suite 2000, Houston, Texas 77002. Our telephone number is (713) 830-6800.

Business Strategy

We strive to maximize shareholder value by growing reserves, production, cash flow and net asset value on a per share basis while maintaining our financial flexibility and discipline. We incorporate the following operating philosophies in executing our strategy:

Pursue a Balanced Growth Strategy. We pursue a strategy of exploiting our existing reserves, exploring for new reserves and acquiring new properties. We invest in exploitation and development projects intended to generate cash flows from which we can fund future expansion opportunities. Founded as an exploration company, we supplement our exploitation activities by continuing to invest in exploratory prospects. We enhance our exploitation and exploration activities with acquisitions of new properties that we believe offer significant unexploited reserve potential and that conform to our operating philosophy.

Focus on Natural Gas. By design, our assets are concentrated in natural gas prone areas in the United States, and our production and reserve base is heavily weighted toward natural gas. As of December 31, 2004, approximately 94% of our proved reserves were natural gas and, for the year ended December 31, 2004, approximately 93% of our production was natural gas. As a commodity, natural gas is more difficult to import into the United States than oil and is therefore better insulated than oil from the competition of foreign imports and geopolitical instability. Lease operating expense is typically lower for gas properties than oil, allowing a higher cash margin. While we believe that the growing demand for natural gas in the United States, measured against the maturing domestic natural resource base, provides attractive pricing fundamentals for natural gas in the foreseeable future, we have explored and intend to continue to explore opportunities to balance our asset portfolio with additional oil reserves. Such activities depend on the relative pricing outlook for the commodities, acquisition opportunities, and operational considerations, including our objectives of shifting a greater portion of our operations onshore, lowering our finding and development costs, and lengthening our reserve life.

Maintain Significant Operating Control. Whenever possible, we prefer to operate our properties as it gives us more control over the nature and timing of capital expenditures and overall operating expenses. We currently operate approximately 77% of our wells, with our average working interest as of December 31, 2004, of approximately 72%.

Concentrate on Core Areas. Our strategy of focusing drilling activities on properties in relatively concentrated areas, both onshore and offshore, permits us to more efficiently utilize our base of geological, engineering, exploration and production experience and expertise in these regions. By concentrating our operations, we can manage a large asset base with a relatively small number of employees and can integrate additional properties at relatively low incremental costs. At December 31, 2004, approximately 95% of our reserves were located in three core areas: South Texas, the Gulf of Mexico and the Arkoma Basin. We expect to continue our efforts to develop our Rocky Mountain operations into a core area and plan to cultivate one or more new core areas where we believe we can sustain our future growth.

Strive to Be a Low Cost Producer. We strive to minimize our operating costs by concentrating our assets within geographic areas where we can consolidate a relatively high degree of operating control and capture operating efficiencies. Although we expect our costs will increase in 2005, we believe that our operating structure provides us a significant competitive advantage because it maximizes our margins and cash flows. For 2004, our lease operating expense was $0.45 per Mcfe.

Employ Conservative Financial Policies. We typically fund our exploitation and exploration activities out of cash flows from operations. Historically, we have funded acquisitions through our revolving bank credit facility, focusing on prompt repayment in order to minimize our debt service obligations. While our debt levels have historically increased periodically in connection with acquisitions, and are expected to increase from time to time in the future as we continue to make acquisitions, we strive to maintain conservative debt levels in order to allow ourselves flexibility to continually review and adjust our capital budgets during the year based on operational developments, commodity prices, service costs, acquisition opportunities and numerous other factors. In the future, we may issue common stock in connection with acquisitions, either initially as an element of the transaction consideration or subsequently as part of a financing plan. In addition, we employ an active hedging program designed to reduce our exposure to adverse commodity price fluctuations and provide more predictable cash flows that allow us to plan and fund our capital expenditures.

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Properties and Operating Areas

The table below summarizes certain data for our core operating areas for the year ended December 31, 2004.

Activity and Balances as of or for the Year Ended December 31, 2004

Area	Average Daily Production	Total Production	Total Proved Reserves	Percentage Total Proved Reserves	Wells Drilled Total	Wells Drilled Successful
	(MMcfe/d)	(MMcfe)	(MMcfe)		(Gross)	(Gross)
South Texas	142	51,930	326,815	41%	76	56
Gulf of Mexico	153	56,088	291,477	37%	19	15
Arkoma Basin	38	13,735	131,262	17%	79	73
Rocky Mountains	1	272	22,116	3%	31	28
Other	5	1,960	21,454	2%	6	5
Total	339	123,985	793,124	100%	211	177

South Texas. Our South Texas properties are concentrated in the Charco, Haynes and South Trevino Fields of Zapata County; the Alexander, Hubbard and South Laredo Fields of Webb County; and the Northeast Thompsonville Field in Jim Hogg County. As of December 31, 2004, our South Texas properties cover approximately 67,900 net acres and we own interests in 640 producing wells, 534 or 83% of which we operate. Our average working interest is 83%. Average well depth is between 8,000 to 12,500 feet with production from the Wilcox formations.

When we acquired the Charco Field in July 1996, it had approximately 150 producing wells and average daily production was 38 MMcfe per day, net to our interest. We expanded our existing production and reserve base with the acquisition of the Alexander, Hubbard and South Laredo Fields in December 2001, and again, in May 2002, with the acquisition of the Northeast Thompsonville Field. During 2004, we expanded our acreage position in Zapata County with the acquisition of undeveloped acreage in the Cisco-Benavides Field for $2.7 million, and purchased incremental working interests in several producing wells in the North East Thompsonville Field for $3.3 million. In total, our net South Texas production has more than tripled since July 1996, to an average of 142 MMcfe per day during 2004, which compares to 140 MMcfe per day in 2003. Over the course of eight and a half years, we have drilled 284 successful wells at an average success rate of 80%, produced 293 Bcfe and added 507 Bcfe in reserves through drilling and acquisitions. As we see our South Texas properties begin to mature and production growth to minimize, we plan to maintain production at existing levels while improving drilling and operating efficiencies in an effort to control finding and operating costs.

Gulf of Mexico. Our offshore properties are located in the shallow waters of the Outer Continental Shelf. Our key producing properties are located in the western and central Gulf of Mexico and include the Mustang Island, High Island, East Cameron, Vermilion and West Cameron areas. In October 2003, we added to our existing production base through the acquisition of 11 producing fields in the central Gulf of Mexico. The properties were purchased for a net $147.5 million and had estimated proved reserves of 88.5 Bcfe at October 15, 2003. During the second half of 2004, we again added to our offshore shore production base through two producing property acquisitions. On a combined basis, the properties were purchased for a net $139.8 million, had estimated proved reserves of 76.9 Bcfe at acquisition, and covered 12 blocks in the Central Gulf of Mexico. As of December 31, 2004, we hold interests in 142 blocks in federal and state waters, of which 78 are developed. As of December 31, 2004, we operated 45 of our developed blocks, which accounted for approximately 70% of our offshore production during 2004. We have a total of 92 producing platforms and production caissons, of which we operate 60. During 2004, production from our Gulf of Mexico properties averaged 153 MMcfe per day.

During the last two years, our offshore operation has evolved from almost exclusively an exploration focus to a blended enterprise with substantial elements of new project exploration and exploitation activities aimed at maximizing production from older, previously produced fields acquired from third parties. Going forward, we expect to continue to evaluate the profitability of each of our core operating areas and shift our emphasis between exploration and exploitation in response to operational developments and economic factors.

Arkoma Basin. Our Arkoma Basin properties are located in two primary areas: the Chismville/Massard Field located in Logan and Sebastian Counties of Arkansas and the Wilburton and South Panola Fields located in Latimer County, Oklahoma. At December 31, 2004, we had approximately 35,400 net acres under lease and we owned working interests in 349 producing natural gas wells, 232 of which we operated. Wells average a depth of 5,500 feet and production is from the Atoka formation. As a result of continued downspacing of in-field drilling by the Arkansas Oil and Gas Commission, first in September 2002 from 680 acres to 160 acres per well and again in September 2003 from 160 acres per well to 80 acres per well, we were able to increase the number of wells drilled during 2004 to 79 wells from 51 wells drilled in 2003 and 24 wells drilled in 2002. During 2004, average daily production increased by 65% from 23 MMcfe per day during 2003 to 38 MMcfe per day during 2004. Acquisition values in the Arkoma Basin have impeded the expansion of our operations beyond our existing acreage position and, as a result, our current activities are focused on the substantial number of in-field drilling opportunities within our existing acreage. The Arkansas Oil and Gas Commission has approved downspacing from 320 acres per well in 2002 to approximately 40 acres per well as of December 2004, facilitating the expansion of our in-field drilling opportunities.

Rocky Mountains. During 2003, we began a lease acquisition initiative in the Rocky Mountain region, initially leasing more than 200,000 net undeveloped acres encompassing portions of the Uinta Basin of Northeastern Utah, the Williston Basin spanning North and South Dakota, the Crazy Mountain Basin of Southwestern Montana, and the Green River Basin of Southwestern Wyoming. Our primary focus for 2004 was proving up and delineating portions of our Uinta Basin acreage, where we drilled a total of 26 wells, of which 25, or 96%, were successful. At December 31, 2004, 19 of our Uinta wells were shut-in and awaiting approvals for pipeline right-of-ways. In January 2005, 11 of the 19 Uinta wells came on-line with estimated initial production rates, on a combined basis, of approximately 8 MMcfe per day, net to our interest.

In August 2004, we acquired approximately 330,000 net acres in the DJ Basin of Eastern Colorado. During the second half of 2004, we drilled four wells and successfully completed three or 75%. Pipeline installation and hookup are expected for these DJ Basin wells during 2005. At December 31, 2004, we had estimated proved reserves in the Rocky Mountains of 22 Bcfe and our daily production averaged 4 MMcfe per day, net to our interests.

Other. As of December 31, 2004, other includes our East Texas properties and two fields located in Central Mississippi. The East Texas properties are located in the Willow Springs Field in Gregg County, Texas and include interests in 24 wells, all of which we operate. The Mississippi properties were acquired in October 2004 as part of our acquisition of 10 offshore blocks in the shallow waters of the Central Gulf of Mexico and consist of two fields containing three producing wells, all of which are non-operated. The Wausau Field is located in Wayne County and the Oakvale Dome Field is located in Jefferson Davis County. In addition to these properties, we have interests or rights of an immaterial nature in other prospective properties or projects with respect to which no reserves are currently associated, and may make future investments of immaterial amounts in similar such projects from time to time in the future.

2004 Divestures

In February 2004, we completed the sale of our South Louisiana properties for net proceeds of $13.1 million. The properties were located in the South Lake Arthur and Lake Pagie Fields located primarily in Vermilion and Terrebonne Parishes. The properties represented 12.3 Bcfe proved reserves as of December 31, 2003, and included interests in 33 gross (9.5 net) producing wells and covered approximately 6,300 gross (2,300 net) acres. Production averaged 5 MMcfe/day during 2003.

In June 2004, we divested of our Appalachian Basin assets as part of an asset exchange transaction with KeySpan. The properties were located primarily in central West Virginia and included the Belington, Clarksburg and Seneca Upshur Fields located in Barbour, Randolph, Upshur and Mingo Counties of West Virginia. Included were the assets acquired on December 31, 2003 from EnerVest East Limited Partnership that were located adjacent to our existing base in the Crawford and Pennsboro Fields in Lewis, Harrison, Tyler and Ritchie Counties of West Virginia and the Waynesburg and Yatesboro Fields in Greene and Armstrong Counties of southwestern Pennsylvania. Based on internal estimates at June 1, 2004, the properties had 51.2 Bcfe of proved reserves with an agreed upon fair value of $60 million. Our average daily production was approximately 8 MMcfe/day at May 21, 2004. We had approximately 207,000 gross (129,000 net) acres under lease and owned working interests in approximately 1,414 gross (1,035 net) wells, of which we operated approximately 92% of the wells.

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Natural Gas and Oil Reserves

The following table summarizes the estimates of historical net proved reserves as of December 31, 2004, 2003 and 2002, and the present values attributable to these reserves at these dates. The reserve data and present values were fully engineered by Netherland, Sewell & Associates, Inc. or Miller and Lents, Ltd., independent petroleum engineering consultants.

	As of December 31,		
Net Proved Reserves:	**2004**	**2003**	**2002**
		(in thousands)	
Natural gas (MMcf)	749,114	709,883	610,409
Oil and natural gas liquids (MBbls)	7,335	7,481	6,533
Total (MMcfe)	793,124	754,769	649,607
Standardized measure of discounted future net cash flows (1)	$ 1,440,055	$ 1,504,406	$ 1,058,064

(1) The standardized measure of discounted future net cash flows has been calculated in accordance with SFAS 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 flows from our hedging program.

In accordance with applicable requirements of the SEC, we estimate net proved reserves and future net revenues using sales prices estimated to be in effect as of the date we make the reserve estimates. Sales price estimates are held constant throughout the life of the properties, except to the extent a contract specifically provides for escalation. Natural gas and oil prices have fluctuated widely in recent years. Volatility is expected to continue and price fluctuations directly affect estimated quantities of proved reserves and future net revenues. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control.

The reserve data contained in this Annual Report 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 prepared by one engineer may vary from those prepared by another. Estimates are subject to revision based on numerous factors including reservoir performance, prices and economic conditions. In addition, results of drilling, testing and actual production subsequent to the date of estimate may justify revision of that estimate. Revisions to prior estimates may be material. Reserve estimates are often 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.

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Drilling Activity

We engage in numerous drilling activities on properties presently owned by us and intend to drill or develop other properties we may acquire in the future. The following table sets forth the results of our drilling activities for the years ended December 31, 2004, 2003 and 2002. Gross wells are the sum of all wells in which we owned an interest. Net wells are the sum of our working interests in the gross wells.

	Exploratory				Development				Total Wells Drilled					
	Successful		Dry		Successful		Dry		Successful		Dry		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2004														
South Texas			1	1.0	56	54.6	19	18.0	56	54.6	20	19.0	76	73.6
Gulf of Mexico	3	1.4	4	2.2	12	9.3			15	10.7	4	2.2	19	12.9
Arkoma Basin					73	45.8	6	3.0	73	45.8	6	3.0	79	48.8
Rocky Mountains	26	25.4	3	2.3	2	2.0			28	27.4	3	2.3	31	29.7
Other			1	0.5	5	5.0			5	5.0	1	0.5	6	5.5
Total areas 2004	29	26.8	9	6.0	148	116.7	25	21.0	177	143.5	34	27.0	211	170.5
2003														
South Texas	3	3.0	3	3.0	53	51.3	18	17.5	56	54.3	21	20.5	77	74.8
Gulf of Mexico	6	2.4	8	3.6	3	2.0			9	4.4	8	3.6	17	8.0
Arkoma Basin			1	0.4	46	28.6	4	2.5	46	28.6	5	2.9	51	31.5
Other					2	2.0			2	2.0			2	2.0
Total areas 2003	9	5.4	12	7.0	104	83.9	22	20.0	113	89.3	34	27.0	147	116.3
2002														
South Texas	2	2.0	1	1.0	52	52.0	8	8.0	54	54.0	9	9.0	63	63.0
Gulf of Mexico	6	2.0	1	0.4	3	1.1			9	3.1	1	0.4	10	3.5
Arkoma Basin			1	0.8	21	12.0	2	1.4	21	12.0	3	2.2	24	14.2
Total areas 2002	8	4.0	3	2.2	76	65.1	10	9.4	84	69.1	13	11.6	97	80.7

As of December 31, 2004, we were drilling or participating in the drilling of 22 gross (18.2 net) wells. Of these wells, through February 22, 2005, 17 gross (15.9 net) wells have been determined to be successful and 2 gross (1.5 net) were unsuccessful, with the remaining 3 gross (0.8 net) wells still in progress.

Productive Wells

The following table sets forth the number of productive wells in which we owned an interest as of December 31, 2004. Productive wells consist of producing wells and wells capable of production, including 28 wells, 22 of which were located in the Rocky Mountains, awaiting connections. Wells that are completed in more than one producing horizon are counted as one well. The operator is the designated party under the terms of an operating agreement that manages the day-to-day operations of the well.

	As of December 31, 2004									
	Natural Gas Wells				Oil Wells				Total Wells	
	Operated		Non-Operated		Operated		Non-Operated			
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
South Texas	534	517.7	106	14.8					640	532.5
Gulf of Mexico	101	81.6	48	15.0	16	12.1	6	1.1	171	109.8
Arkoma Basin	232	159.2	117	26.5					349	185.7
Rocky Mountains	36	34.1							36	34.1
Other	24	16.9	3	1.7					27	18.6
Total	927	809.5	274	58.0	16	12.1	6	1.1	1,223	880.7

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, 2004. 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. Gulf of Mexico acreage includes leases in federal and state waters.

	As of December 31, 2004					
	Undeveloped		Developed		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
South Texas	17,467	14,952	67,670	52,901	85,137	67,853
Gulf of Mexico	225,534	161,455	303,444	182,814	528,978	344,269
Arkoma Basin	18,958	7,088	59,707	28,322	78,665	35,410
Rocky Mountains	665,876	505,001	7,337	7,337	673,213	512,338
Other			5,319	3,351	5,319	3,351
Total	927,835	688,496	443,477	274,725	1,371,312	963,221

Undeveloped Acreage Expirations

The table below summarizes by year and area our undeveloped acreage scheduled to expire in the next five years.

	As of December 31, 2004									
	2005		2006		2007		2008		2009	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
South Texas	5,588	4,927	5,313	3,029	4,783	4,783				
Gulf of Mexico	39,871	36,538	31,137	23,909	46,181	37,921	62,824	35,215	47,280	28,324
Arkoma Basin					2,816	924				
Rocky Mountains	1,601	1,601	208,113	146,659	112,841	88,823	148,332	123,367	27,318	16,720
Total	47,060	43,066	244,563	173,597	166,621	132,451	211,156	158,582	74,598	45,044

Marketing and Customers

We market the majority of the natural gas and oil production from properties we operate for both our account and the account of the other working interest owners in these properties. We typically sell a substantial portion of our production under short-term (usually one-month) fixed price contracts tied to a local index. We do not have any material long-term, fixed price sales contracts. The remaining portion of our production is sold on a daily basis into local spot markets in order to accommodate fluctuations in daily production volumes. 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 one or all of our major purchasers would not have a material adverse effect on our financial condition and results of operations. For a list of our purchasers that accounted for 10% or more of our natural gas and oil revenues during the preceding last three calendar years, see Notes to Consolidated Financial Statements Note 8 Sales to Major Customers.

We enter into hedging transactions 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. For a more detailed discussion, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

We incur gathering and transportation expenses to move our natural gas from the wellhead to a purchaser-specified delivery point. These expenses vary based on the volume and distance shipped, and the fee charged by the third party transporter. We do not have any material transportation agreements and we have not contracted for firm capacity for which we would pay monthly demand charges. Our natural gas and oil are transported through third party gathering systems and pipelines. Transportation space on these gathering systems and pipelines is occasionally limited and at times unavailable because of repairs or improvements, or as a result of priority transportation agreements with other gas shippers. 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. See the section entitled Risk Factors *Our business depends on oil and natural gas transportation facilities that are owned by others*.

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Title to Properties

As is customary in the oil and gas industry, we initially conduct only a cursory review of the title to undeveloped acreage in farm-out agreements and natural gas and oil leases. 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. Prior to completing an acquisition of producing natural gas and oil leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion. Our natural gas and oil properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

Competition

We encounter intense competition from other oil and gas companies in all areas of our operations, including the acquisition of additional properties and acreage. This competition is intensifying in response to rising natural gas price levels and the natural maturation of several of our key fields. 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 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. Our ability to acquire additional properties and to discover new 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.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas increases during the winter months as a result of heating applications and decreases during the summer months. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, as the industrial use of natural gas has expanded in recent years, weather related demand and seasonal fluctuations are diminishing. However, seasonal weather conditions, such as tropical weather in the Gulf of Mexico and winter weather in the Rocky Mountain region can pose challenges for meeting our well drilling and production objectives.

Regulation

The oil and gas industry is extensively regulated by numerous federal, state and local authorities, including Native American tribes. 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, and Native American tribes 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, and some counties, municipalities and Native American tribes, in which we operate also regulate one or more of the following:

the location of wells;

the method of drilling and casing wells;

the rates of production or allowables;

the surface use and restoration of properties upon which wells are drilled; and

the plugging and abandoning of wells.

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State laws regulate the size and shape of drilling and spacing units or proration units governing the 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 some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. 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 laws and 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. Our properties located in federal waters are regulated by the Minerals Management Service and are not subject to regulation by state agencies.

We conduct our operations in the Gulf of Mexico on oil and natural gas leases that 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. In certain instances, substantial Certificates of Financial Responsibility or other acceptable assurances must be provided and maintained under the federal Oil Pollution Act of 1990.

The Minerals Management Service promulgates and enforces regulations that require offshore production facilities located on the Outer Continental Shelf to meet stringent engineering, construction, and safety specifications, that impose strong restrictions on the flaring or venting of natural gas, that prohibit the burning of liquid hydrocarbons and oil without prior authorization, and that govern the plugging and abandonment of offshore wells and removal of offshore production facilities. To cover the various obligations of lessees on the Outer Continental Shelf, the Minerals Management Service generally requires that lessees post and maintain 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 are subject to and must comply with the same federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection as other companies in the oil and gas exploration and production industry. These laws and regulations may:

- require the acquisition of a permit before drilling commences;
- require the installation of expensive pollution control measures;
- 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. For the year ended December 31, 2004, we did not incur any material capital expenditures for environmental control facilities. As of the date of our Annual Report, we are not aware of any environmental issues or claims that will require material expenditures during 2005 or that will have a material impact on our financial position or results of operations.

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The most significant of these environmental laws and regulations include, among others, the:

Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act, or RCRA, 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. Indeed, legislation has been proposed from time to time in Congress to recategorize certain oil and gas exploration and production wastes as hazardous wastes.

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, registrations and other authorizations 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, governmental agencies or third parties may seek to hold us responsible under CERCLA for all or part of the costs to clean up sites at which such hazardous substances have been deposited. As of the date of our report, however, we have no knowledge of having 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 and offers few defenses to such liability. 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 permittee 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 have received certification from the Minerals Management Service that due to our financial status, we are able to cover a minimum of $35 million per occurrence and because we do not have major oil producing facilities, the maximum certification of $150 million in coverage is not currently required. As such, we currently believe we are in substantial compliance with the financial responsibility provisions of the Oil Pollution Act.

Federal Water Pollution Control Act/Clean Water Act. The Federal Water Pollution Control Act or Clean Water 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. Regulations governing water discharges also impose other requirements, such as the obligation to prepare spill response plans. We currently believe that we are in substantial compliance with all pollutant, wastewater, and stormwater discharge regulations and that we hold all necessary and valid permits, other required authorizations, and spill response plans 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, EPA has developed and continues to develop more stringent regulations governing emissions of toxic air pollutants. These regulations may increase the costs of compliance for some facilities. We currently 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.

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In 1997, numerous countries participated in an international conference under the United Nations Framework Convention on Climate Change and concluded an agreement, known as the Kyoto Protocol. The Protocol became effective February 14, 2005, and will require reductions of certain emissions that contribute to atmospheric levels of greenhouse gases. The United States has not ratified the Protocol but may in the future. Presently, it is not possible to accurately estimate the costs we could incur to comply with any laws or regulations developed to achieve such emissions reductions, but such expenditures could be substantial.

Legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including oil and gas facilities. Our operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs we could incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Natural Gas Sales Transportation. Historically, federal legislation and regulatory controls have affected 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 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 affects 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, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are 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 nor can we determine what affect, if any, future regulatory changes might have on our natural gas related activities.

Under FERC s current regulatory regime, transmission services must be provided on an open-access, non-discriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. 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 certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point-of-sale locations.

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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, our revenues are highly dependent on the price of, and demand for, natural gas and oil. Even relatively modest changes in natural gas and oil 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;
- weather conditions;
- the price of foreign imports;
- overall domestic and global economic conditions;
- terrorist attacks or military conflicts;
- political and economic conditions in oil producing countries;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the level of consumer product demand;
- speculation in the commodity futures markets;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations, including regulations imposed by Native American tribes;
- approvals, proximity and capacity of natural gas and oil pipelines and other transportation facilities; 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.

We utilize the full cost method of accounting for natural gas and oil exploration and development activities. Under full cost accounting, we are required by SEC regulations to perform a ceiling test each quarter. The ceiling test is an impairment test and generally establishes a maximum, or ceiling, of the book value of our natural gas and oil properties that is equal to the expected after tax present value (discounted at 10%) of the future net cash flows from proved reserves, including the effect of cash flow hedges, calculated using prevailing prices on the last day of the period. If the net book value of our natural gas and oil properties (reduced by any related net deferred income tax liability and asset retirement obligation) exceeds our ceiling limitation, SEC regulations require us to impair or writedown the book value of our natural gas and oil properties. Depending on the magnitude of any future impairments, a ceiling test writedown could significantly reduce our income, or produce a loss. As ceiling test computations involve the prevailing price on the last day of the quarter, it is impossible to predict the timing and magnitude of any future impairments. The book value of our proved natural gas and oil properties increased in 2004 as a function of our higher acquisition, exploration and development costs for the year and the increase in future development costs associated with reserves added during the year. To the extent our finding and development costs continue to increase, we will become more susceptible to ceiling test writedowns in low price environments.

Lower natural gas and oil prices could negatively impact our ability to borrow.

The amount of borrowings available to us under our revolving bank credit facility is determined by reference to a borrowing base. The amount of our borrowing base is established by our banks and is primarily a function of the quantity and value of our reserves. Our borrowing base is re-determined at least twice a year to take into account changes in our reserve base and prevailing commodity prices. Our current borrowing base is $400 million. Commodity prices can affect both the value as well as the quantity of our reserves for borrowing base purposes as certain reserves may not be economic at lower price levels. Additionally, the indenture governing our 7% senior subordinated notes due 2013 conditions our ability to incur additional indebtedness on our satisfaction of tests relating to earnings before interest, taxes and depreciation, depletion and amortization expense and consolidated net tangible assets (as defined in the indenture), both of which are sensitive to commodity prices. Consequently, the amount of borrowing available to us under our revolving bank credit facility as well as our ability to incur additional indebtedness under our senior subordinated notes could be adversely affected by extended periods of low commodity prices.

The high-rate production characteristics of our properties subject us to high reserve replacement needs and require significant capital expenditures to replace our reserves at a faster rate than companies whose reserves have longer-life production profiles.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as they are produced. Producing natural gas and oil reservoirs are generally characterized by declining production rates that vary depending on reservoir characteristics and other factors. Virtually all of our onshore production is located in prolific natural gas producing regions where completion techniques result in hyperbolic production decline profiles characterized by high initial production rates, followed by rapid intermediate production declines, and culminating in a long-term low production rate subject to a shallow decline. Likewise, our offshore production is generally characterized by small reservoirs with high porosity and permeablilty rocks that produce at very high rates but typically deplete rapidly. Because of the high-rate production profiles of our properties, replacing produced reserves is more difficult for us than for companies whose reserves have longer-life production profiles. This imposes greater reinvestment risk for our company as we may not be able to continue to replace our reserves or may not be able to do so at an acceptable finding cost.

Rising finding and development costs may impair our profitability.

In order to continue to grow and maintain our profitability, we must annually add new reserves exceeding our yearly production at a finding and development cost that yields an acceptable operating margin and depreciation, depletion and amortization rate. Without cost effective exploration, development or acquisition activities, our production, reserves and profitability will decline over time. Given the relative maturity of most gas basins in North America the cost of finding new reserves through exploration and development operations has been increasing. The acquisition market for natural gas properties has become extremely competitive among producers for additional production and expanded drilling opportunities in North America. Acquisition values climbed toward historic highs during 2004 on a per unit basis, particularly in our focus areas of South Texas and the Rocky Mountain regions, and we believe these values may continue to increase in 2005. For full cost companies such as ours, this increase in finding and development costs is resulting in higher depreciation, depletion and amortization rates. If the upward trend in finding and development costs continues, we and other full cost companies will be exposed to an increased likelihood of a writedown in carrying value of our natural gas and oil properties in response to falling prices, which would impair our profitability.

The success of our business depends upon our ability to find, replace, develop and acquire natural gas and oil reserves.

Without successful exploration, development or acquisition activities, our oil and gas reserves and our revenues will decline over time. In addition, we may not be able to maintain our current cost structure while continuing to operate in mature producing basins. It is becoming more difficult to find, replace and develop new reserves at historical costs. 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 amount of borrowing capacity available under our revolving bank credit facility is based, in large part, on the estimated quantities of our proved reserves. Without continued capital investment, our oil and gas reserves will decline.

Estimates of proved reserves and future net revenue may change if the assumptions on which such estimates are based prove to be inaccurate.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. 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 and natural gas. Natural gas and oil prices have fluctuated widely in recent years. Volatility is expected to continue and price fluctuations directly affect estimated quantities of proved reserves and future net revenues. 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. Also, we make certain assumptions regarding future

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natural gas and oil prices, production levels, and operating and development costs that may prove incorrect. 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 and natural gas prices after the date of the estimate may result in revisions to our reserve estimates. During 2004 and 2003, we incurred downward revisions of our proved reserves of 20 Bcfe and 40 Bcfe, respectively, either from proved undeveloped reserves that were depleted or otherwise not recoverable, or from production performance indicating less gas in place or smaller reservoir size than initially estimated.

The reserve data contained in this Annual Report 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 prepared by one engineer may vary from those prepared by another. Estimates are subject to revision based on numerous factors including, reservoir performance, prices and economic conditions. In addition, results of drilling, testing and actual production subsequent to the date of estimate may justify revision of that estimate. Revisions to prior estimates may be material. Reserve estimates are often 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 acquisition and investment activities may be unsuccessful and costly.

The successful acquisition of producing properties requires assessment of reserves, future commodity prices, operating costs and potential environmental and other liabilities. These assessments may not be accurate. Our review of the properties we intend to acquire may not reveal all existing or potential problems nor allow us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We may not always perform inspections on every property 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.

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. If our revenues or borrowing base under our revolving 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. 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.

Our business involves many operating risks that can cause substantial losses; insurance may not protect us against all these risks.

In our operations we may experience hazards and risks inherent in drilling for, producing and transporting 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, including adverse weather conditions;

explosions;

encountering formations with abnormal pressures;

encountering unusual or unexpected geological formations;

blowouts;

cratering;

unexpected operational events;

equipment malfunctions;

- pipeline ruptures;
- spills;
- compliance with environmental and government regulations; and
- title problems.

We are insured against some, but not all, of the hazards associated with our business, although 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 or are underinsured. The occurrence of an event that is not covered or not fully covered by insurance could have a material adverse impact on our financial condition and results of operations.

Our reserves, production and cash flow are highly dependent upon operations that are concentrated in three primary areas.

During 2004, we generated approximately 98% of our production from three primary areas of operation, with 42% from South Texas, 45% from offshore Gulf of Mexico and 11% from the Arkoma Basin. The concentrated nature of our operations subjects us to the risk that a regional event could cause a significant interruption in our production or otherwise have a material affect on our profitability. This is particularly true of our offshore operations, which are susceptible to weather disturbances, some of which can be severe enough to cause substantial damage to facilities and production infrastructure.

Drilling natural gas and oil wells is a high-risk activity and subjects us to a variety of factors that we cannot control.

Our drilling activities subject us to many risks, including the risk that we will not find commercially productive reservoirs. Drilling for natural gas and oil can be unprofitable, not only from dry wells, but also from productive wells that do not produce sufficient revenues to return a profit. Also, title problems, weather conditions, governmental requirements and shortages or delays in the delivery of equipment and services can delay our drilling operations or result in their cancellation. The cost of drilling, completing and operating wells is often uncertain, and new wells may not be productive. As a result, we may not recover all or any portion of our investment.

Our hedging activities could result in financial losses or reduce our income.

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently and expect to in the future enter into hedging arrangements for a significant portion of our natural gas and oil production. For both 2005 and 2006, we have entered into derivative instruments relating to approximately 70% of our planned production utilizing a variety of instruments, including fixed price swaps and collars. We have begun to establish hedging positions for 2007 and 2008. The derivative instruments that we employ require us to make cash payments to the extent the NYMEX index exceeds a predetermined price, thereby limiting our ability to realize the benefit of increases in natural gas prices. As we typically index our derivative instruments to NYMEX prices as opposed to the local indices where we sell our gas, our hedging strategy may not protect our cash flows if basis differentials increase between the NYMEX and local prices. Under SFAS 133, our income could be negatively affected to the extent our NYMEX-indexed derivative instruments are deemed ineffective in hedging price fluctuations at our sales points. In addition, if we experience a sustained material interruption in our production, we might be forced to satisfy all or a portion of our hedging obligations without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. Another risk of hedging activities is that the counterparty in any derivative transaction cannot or will not perform under the instrument and that we will not realize the benefit of the hedge. It is also important to note that it is not practical to hedge the cash flows relating to all of our production, and we therefore retain the risk of a price decrease on our unhedged volumes.

The availability and cost of rigs, equipment, and personnel could adversely affect our profitability and level of operations.

Driven by attractive commodity prices, domestic drilling activity measured as a function of rig utilization has been at very high levels throughout 2003 and 2004. Given this extended strong demand for drilling rigs and other oil field services necessary to our operation, we began experiencing increased service and material costs in the second half of 2004, as well as longer lead times and reduced service availability. We anticipate that this trend will continue in 2005. If current utilization rates continue at fourth-quarter 2004 levels or increase, a general shortage of drilling and completion rigs, field equipment and qualified personnel could develop, especially in the areas where we operate. Should this transpire, the costs and delivery times of rigs, equipment and personnel could be substantially greater than in previous years. If we do not have

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access to necessary oil field services at a reasonable cost, we could be forced to curtail certain operations and the profitability of those operations that we do conduct could be materially impaired.

Our business depends on oil and natural gas transportation facilities that are owned by others.

The marketability of our natural gas and oil production depends in part on the availability, proximity and capacity of pipeline systems owned by third parties. The unavailability of or lack of available capacity on these systems and related facilities could result in the shut-in of producing wells or the delay or discontinuation of development plans for properties. Although we have some control over the transportation of our product, material changes in these business relationships could materially affect our operations. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

Our investments in the Rocky Mountains may not be successful.

Our future growth plans rely in part on establishing significant production and reserves in the Rocky Mountains, particularly the Uinta Basin in Utah and the DJ Basin in Colorado. To date, we lack sufficient production history from these areas to accurately estimate the likelihood that our endeavors will yield meaningful reserves and production with an acceptable rate of return. Certain of our exploration objectives in the Rocky Mountain area involve geology types and mechanical operations that differ substantially from our historic operations in South Texas and the Arkoma Basin. In addition, operations in the Rocky Mountain region present unique operational challenges, such as more acute transportation constraints, higher pricing differentials, and more extensive regulatory oversight. For example, 22 of the 25 successful wells that we drilled during 2004 in the Uinta Basin where shut in at year end awaiting right of way approval from the U.S. Bureau of Land Management (the BLM). Increased drilling in the vicinity of our Rocky Mountain acreage has also resulted in the EPA increasingly requiring the preparation of environmental assessments or more comprehensive environmental impact statements, as a condition to conducting operations on certain lands that the BLM administers. Any or all of these contingencies could delay or halt our drilling activities or the construction of ancillary facilities necessary for production, which would prevent us from developing our property interests in the Rocky Mountains as planned. This could in turn impede our growth, as we intend to undertake significant activity in order to increase our production and reserves in this area in the future.

We may incur substantial costs to comply with costly and stringent environmental and other governmental laws and regulations.

Our exploration and production operations are regulated extensively at the federal, state, and local levels. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigating and remedial obligations, and the issuance of injunctions limiting or prohibiting our operations. We have made and plan to continue making all necessary expenditures, both financial and managerial, in our efforts to comply with the requirements of environmental and governmental regulations. However, environmental laws and regulations, including those that may at some time arise to address global climate change or facility security concerns, are expected to continue to have an increasingly costly and stringent impact on our operations resulting in substantial costs and liabilities in the future.

We currently own, lease, and have in the past owned or leased, numerous properties that have been used for the exploration and production of oil and gas for many years. Although we have used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed or released on or under the properties owned or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, petroleum hydrocarbons or wastes may have been disposed or released by prior operators of properties that we are acquiring as well as by current third party operators of properties in which we have an ownership interest. Properties impacted by any such disposal or releases could be subject to costly and stringent investigatory or remedial requirements under environmental laws, some of which impose strict, joint and several liability without regard to fault or the legality of the original conduct, including the federal Comprehensive Environmental Response, Compensation, and Liability Act, also known as CERCLA or the Superfund law, the federal Oil Pollution Act or OPA, the federal Resource Conservation and Recovery Act or RCRA, and analogous state laws. Under such laws and any implementing regulations, we could be required to remediate contaminated properties and take actions to compensate for damages to natural resources. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury or property damages allegedly caused by the release of petroleum hydrocarbons or wastes into the environment. We currently do not expect any remedial obligations imposed under environmental laws to have a significant effect on our operations.

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.

The inability of one or more of our customers to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable result from natural gas and oil sales or joint interest billings to third parties in the energy 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.

Provisions in our Charter, Agreements, Stockholder Rights Plan and Delaware Law May Inhibit a Takeover of Houston Exploration.

Under our Restated Certificate of Incorporation, our Board of Directors is authorized to issue shares of our common or preferred stock without approval of our stockholders. Issuance of these shares could make it more difficult to acquire our company without the approval of our Board of Directors as more shares would have to be acquired to gain control. We also have a stockholder rights plan, commonly known as a poison pill, that entitles our stockholders to acquire additional shares of our company, or a potential acquirer of our company, at a substantial discount from market value in the event of an attempted takeover without the approval of our Board. The indenture governing our 7% senior subordinated notes due 2013 also contains change of control provisions that, among other things, allow the holders of the notes to require us to repurchase them at 101% of their principal amount, and a change of control constitutes a default under our revolving band credit facility. Finally, Delaware law imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. These provisions may deter hostile takeover attempts that could result in an acquisition of us that would have been financially beneficial to our stockholders.

Employees

As of December 31, 2004, we had 155 full time employees, 121 of whom are located at our headquarters in Houston, Texas and the remainder of whom are located in our South Texas, Arkansas, Denver and East Texas field offices. None of our employees is represented by a labor union or other collective bargaining arrangement. We employ the services of independent consultants and contractors to perform various professional services, particularly in the areas of construction, design and well-site surveillance, permitting and environmental assessment. At our direction, independent contractors usually perform field and on-site production operation services, including pumping, maintenance, dispatching, inspection and testing.

Offices

We currently lease approximately 91,600 square feet of office space in Houston, Texas, at 1100 Louisiana Street, where our principal offices are located. We lease approximately 2,250 square feet of office space in Denver, Colorado, at 700 17th Street. In addition, we maintain field operations offices in South Texas, Arkansas, and East Texas.

Available Information

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are made available free of charge on our website at http://www.houstonexploration.com as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

We have adopted a Code of Business Conduct to provide guidance to our directors, officers and employees on matters of business conduct and ethics, including compliance standards and procedures. We have also adopted a Code of Ethics for Senior Financial Officers that applies to our principal executive officer, principal financial officer, principal accounting officer and controller. Our Code of Business Conduct and Code of Ethics for Senior Financial Officers are available on the Shareholder/Financial section of our web site at www.houstonexploration.com under the heading Corporate Governance. We intend to promptly disclose via a Current report on Form 8-K and on our web site information about any waiver of these codes with respect to our executive officers and directors. Our Corporate Governance Guidelines and the charters of our Audit Committee, Nominating and Corporate Governance Committee, and Compensation Committee are also available on the Shareholder/Financial section of our web site at www.houstonexploration.com under the heading Corporate Governance. In addition, a copy of our Code of Business Conduct, Code of Ethics for Senior Financial Officers, Corporate Governance Guidelines and the charters of the Committees referenced above are available in print at no cost to any stockholder who requests them by writing or telephoning us at the following address or telephone number:

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The Houston Exploration Company
1100 Louisiana Street, Suite 2000
Houston, TX 77002 - 5215
Attention: Corporate Secretary
Telephone: (713) 830-6800

Information contained on or connected to our web site is not incorporated by reference into this Annual Report and should not be considered part of this report or any other filing that we make with the SEC.

Item 2. Properties (see Item 1. Business and Properties)

Item 3. Legal Proceedings

We currently are not a party to any material pending legal or governmental proceedings, other than ordinary routine litigation incidental to our business. While the ultimate outcome and impact of any proceeding cannot be predicted with certainty, our management believes that the resolution of any proceeding 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, 2004.

Part II.

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

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, 2003, through December 31, 2004 as reported on the New York Stock Exchange:

Year Ended December 31, 2004	**High**	**Low**
First Quarter	$ 45.85	$ 35.79
Second Quarter	52.47	41.40
Third Quarter	59.79	48.30
Fourth Quarter	61.80	53.65

Year Ended December 31, 2003	**High**	**Low**
First Quarter	$ 31.45	$ 25.81
Second Quarter	35.20	26.72
Third Quarter	36.28	31.25
Fourth Quarter	37.70	33.35

As of February 22, 2005, 28,457,804 shares of common stock were outstanding, and we had approximately 50 stockholders of record and approximately 14,800 beneficial owners.

Dividends

We have not declared or paid any cash dividends and do not anticipate declaring any dividends in the foreseeable future. We plan to retain our cash for the operation and expansion of our business, including exploration, development and acquisition activities. In addition, our revolving bank credit facility and the indenture governing our 7% senior subordinated notes due June 15, 2013, contain restrictions on the payment of dividends to holders of common stock. For more information, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

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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, 2004. 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,				
	2004	**2003**	**2002**	**2001**	**2000**
	(in thousands, except per share data)				
Income Statement Data:					
Revenues:					
Natural gas and oil revenues	$ 649,087	$ 491,440	$ 344,295	$ 387,156	$ 277,487
Other	1,352	1,312	1,086	1,353	1,738
Total revenues	650,439	492,752	345,381	388,509	279,225
Expenses:					
Lease operating expense	55,925	47,072	33,976	25,291	23,553
Severance tax	11,933	15,958	9,487	11,035	9,757
Transportation expense	11,819	10,387	9,317	7,652	6,892
Asset retirement accretion expense	4,902	3,668			
Depreciation, depletion and amortization	265,148	197,530	171,610	128,736	89,239
Writedown in carrying value				6,170	
General and administrative, net	32,899	19,542	13,077	17,110	8,928
Total operating expenses	382,626	294,157	237,467	195,994	138,369
Income from operations	267,813	198,595	107,914	192,515	140,856
Other (income) expense (1)	(1,058)	(15,746)	(9,070)	119	1,752
Interest expense, net	9,455	8,342	7,398	2,992	11,361
Income before income taxes	259,416	205,999	109,586	189,404	127,743
Income tax provision	96,592	72,187	39,092	66,803	42,485
Income before cumulative effect of change in accounting principle	$ 162,824	$ 133,812	$ 70,494	$ 122,601	$ 85,258
Cumulative effect of change in accounting principle (2)		2,772			
Net income	$ 162,824	$ 131,040	$ 70,494	$ 122,601	$ 85,258
Earnings per share:					
Basic:					
Income per share before cumulative effect of change in accounting principle change	$ 5.50	$ 4.30	$ 2.31	$ 4.06	$ 3.06
		(0.09)			

Cumulative effect of change in accounting principle (2)					
Net income per share basic	$ 5.50	$ 4.21	$ 2.31	$ 4.06	$ 3.06
Diluted:					
Income per share before cumulative effect of change in accounting principle	$ 5.44	$ 4.29	$ 2.28	$ 4.00	$ 3.02
Cumulative effect of change in accounting principle (2)		(0.09)			
Net income per share diluted	$ 5.44	$ 4.20	$ 2.28	$ 4.00	$ 3.02
Weighted average shares basic	29,616	31,097	30,569	30,228	27,860
Weighted average shares diluted	29,932	31,213	30,878	30,645	28,213
Ratio of earnings to fixed charges (3)	15.0x	13.6x	7.6x	12.8x	5.5x

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	Years Ended December 31,				
	2004	2003	2002	2001	2000
	(in thousands)				
Cash Flow Data:					
Net cash provided by operating activities	$ 522,436	$ 390,832	$ 243,869	$ 358,032	$ 200,791
Net cash used in investing activities	505,217	461,822	252,125	368,277	184,512
Net cash (used in) provided by financing activities	(1,211)	55,528	17,668	9,189	(22,106)

	At December 31,				
	2004	2003	2002	2001	2000
	(in thousands)				
Balance Sheet Data:					
Working capital (deficit)	$ (31,884)	$ (36)	$ 10,550	$ 34,314	$ 19,746
Property, plant and equipment, net	1,548,256	1,371,129	1,022,414	938,761	705,390
Total assets	1,722,577	1,509,065	1,151,068	1,059,092	837,384
Long-term debt and notes	355,000	302,000	252,000	244,000	245,000
Stockholders equity	782,920	735,534	592,789	565,881	396,742

(1) For 2004, 2003 and 2002, other income includes $1.2 million, $21.6 million and $9.1 million, respectively, representing recoupments of prior period severance tax expense that were recognized pursuant to the receipt of a high cost/tight sand designation for a portion of our South Texas production in July 2002. See Note 9 Commitments and Contingencies. Additionally, for 2004, other income includes $0.2 million in debt extinguishment expenses incurred during the second quarter of 2004 pursuant to the reduction of our borrowings base from $375 million to $340 million as a result of the disposition of our Appalachian Basin assets. For 2003, other income includes $5.9 million in expenses incurred pursuant to the early redemption of our $100 million 8 5/8% notes in June 2003. See Note 2 Long-Term Debt and Notes. For 2001 and 2000, other expense of $0.2 million and $1.8 million, respectively, represents nonrecurring expenses incurred in connection with a strategic review of alternatives for Houston Exploration and KeySpan s investment in our company, including the possible sale of all or a portion of Houston Exploration. See Note 6 Related Party Transactions.

(2) On January 1, 2003, we adopted SFAS 143, Accounting for Asset Retirement Obligations, which addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. Pursuant to our adoption of SFAS 143, we recognized a charge to income during the first quarter of 2003 of $2.8 million, net of tax, for the cumulative effect of the change in accounting principle. See Note 1 Summary of Organization and Significant Accounting Policies Asset Retirement Obligations.

(3) 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 for calculation.

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

The following discussion is intended to assist you in understanding our business and the results of operations together with our present financial conditions. This section should be read in conjunction with our Consolidated Financial Statements and the accompanying notes included elsewhere in this Annual Report on Form 10-K.

Statements in our discussion may be forward-looking. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. See Forward-Looking Statements and Other Information at the beginning of this Annual Report and Risk Factors Affecting Our Business beginning on page 15 for additional discussion of some of these factors and risks.

Overview of Our Business

We are an independent natural gas and oil producer concentrating on growing reserves and production through the exploration, development, exploitation and acquisition of natural gas and oil reserves in North America. Our core areas of operations are South Texas, offshore in the shallow waters of the Gulf of Mexico and the Arkoma Basin of Oklahoma and Arkansas. During 2003, we initiated operations in the Rocky Mountain Region, with an initial focus in the Uinta Basin of northeastern Utah, and during 2004, we expanded our focus to include the DJ Basin of Eastern Colorado. In February 2004, we divested our South Louisiana assets and in June 2004, we divested our Appalachian Basin assets in connection

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with the KeySpan Exchange transaction described in Note 3 Stockholders Equity *KeySpan Exchange and Offering* of Item 15 contained in this Form 10-K. We operate as one segment as each of our operating areas has similar economic characteristics and each meets the criteria for aggregation as defined in the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) 131, Disclosures about Segments of an Enterprise and Related Information.

At December 31, 2004, net proved reserves were 793 billion cubic feet equivalent or Bcfe, with a present value of future net cash flows before income taxes, discounted at 10% per annum, of $2.2 billion and standardized measure of future net cash flows including income taxes, discounted at 10% per annum, of $1.4 billion. Our reserves are fully engineered on an annual basis by independent petroleum engineers. Approximately 94% of our proved reserves at December 31, 2004, were natural gas, approximately 63% of which were classified as proved developed. As of December 31, 2004, we operated approximately 77% of our producing wells. Daily production averaged 339 million cubic feet of natural gas equivalent or MMcfe in 2004.

We were founded in December 1985 as a Delaware corporation and began exploring for natural gas and oil on behalf 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 and sold approximately 31% of our shares to the public. Through three separate transactions, the first in February 2003 and the last in November 2004, KeySpan completely divested of its investment in the common stock of our company. As of December 31, 2004, KeySpan no longer owned any common stock of our company. See Note 3 Stockholders Equity and Note 6 Related Party Transactions for a complete description of these three transactions.

Source of Our Revenues

We derive our revenues from the sale of natural gas and oil that is produced from our natural gas and oil properties. Revenues are a function of the volume produced and the prevailing market price at the time of sale. The price of natural gas is the primary factor affecting our revenues. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we utilize derivative instruments to hedge future sales prices on a significant portion of our natural gas production. During 2004 and 2003, the use of derivative instruments prevented us from realizing the full benefit of upward price movements and may continue to do so in future periods.

Principal Components of Our Cost Structure

Lease Operating Expenses. The day-to-day costs incurred to bring hydrocarbons out of the ground and to the market together with the daily costs incurred to maintain our producing properties. These costs include: lease operating expense, severance tax and transportation expense, which costs are expected to increase.

Depreciation, Depletion and Amortization. The systematic expensing of the capital costs incurred to acquire, explore and develop natural gas and oil. As a full cost company, we capitalize all costs associated with our acquisition, exploration and development efforts, including interest and certain general and administrative costs, and apportion these costs to each unit of production through depreciation, depletion and amortization expense. Generally, if reserve quantities are revised up or down, the depreciation, depletion and amortization rate per unit of production will change inversely.

Asset Retirement Accretion Expense. The systematic, monthly accretion of the future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities.

General and Administrative Expense. Overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, managing our production and development operations and legal compliance are included in our general and administrative expense. We capitalize general and administrative expense directly related to our acquisition, exploration and development activities.

Interest. We typically finance our working capital requirements and acquisitions with borrowings under our revolving bank credit facility, and longer term, with public traded debt instruments. As a result, we incur substantial interest expense that correlates to both fluctuations in interest rates and our acquisition activity. Acquisitions are a critical element of our growth strategy. We expect to continue to incur significant interest expense as we continue to grow. We capitalize interest directly related to our unevaluated properties that are not being amortized.

Income Taxes. We are subject to state and federal income taxes and are currently in a tax paying position. Prior to 2003, all of our taxes, both federal and state, were deferred; however, during 2003, we utilized all of our net operating loss carryforwards and as a result, we recognized current income tax expense and will continue to recognize current tax expense as long as we are generating taxable income.

Industry Environment

We currently operate in North America. After over 100 years of active natural gas and oil exploration and production within the lower 48 states and Gulf of Mexico, the region is maturing and production growth is slowing or possibly declining. Numerous technological advances during this timeframe, including increasingly sophisticated geophysical tools that allow more accurate identification of reservoirs, horizontal and other drilling technologies that facilitate and enhance the extraction process, and advanced completion techniques have accelerated both production and depletion rates. While new discoveries are still being made in North America, the frequency and size of these discoveries is declining while the finding and development costs are increasing. As a result, given our current technology, domestic natural gas and oil production as a whole may be at or near its peak and can be expected to decline in the future, with the exception of regions such as the Rocky Mountains.

In this mature environment, companies will find it increasingly difficult to replace their reserves through traditional exploration and development efforts, and companies will increasingly be forced to rely on acquisitions to sustain their growth. Our future success in growing our reserve base at an acceptable finding cost will depend in large part on our ability to acquire new proved reserves and unevaluated acreage on which we can explore. We currently maintain a very active acquisition program and expect to continue to devote significant resources to identifying and pursuing both tactical acquisitions that augment our existing property base as well as substantial strategic acquisitions.

We anticipate that the continued decline of the North American gas basins will lead to higher cost structures throughout our industry. We currently believe that the cost of finding, developing and producing new natural gas and oil reserves through exploration and development operations will rise as the industry makes fewer discoveries and such discoveries generally tend to decrease in reserve size. In addition, we believe the acquisition market for natural gas properties has become extremely competitive as producers vie for additional production and expanded drilling opportunities in North America. Acquisition values climbed toward historic highs during 2004 on a per unit basis, particularly in our focus areas of South Texas and the Rocky Mountains, and we expect acquisition values to continue to climb in 2005. For full cost companies such as ours, increases in both acquisition and finding and development costs, are expected to yield higher depreciation, depletion and amortization rates and ultimately, could increase the likelihood of a writedown in carrying value of our natural gas and oil properties if commodity prices fall substantially below current levels. In addition, we expect drilling costs, especially in the Gulf of Mexico, and lease operating expenses to continue to rise as producers are forced to make operational enhancements to maintain aging fields.

Like any commodity, the price that we receive for the gas we produce is largely a function of supply and demand. Demand for natural gas is affected by general economic conditions, such as growth in the space heating, industrial and power generation segments, and seasonal conditions. Demand has also typically been impacted by seasonal fluctuations, with the peak demand during the winter heating season and summer air conditioning season. As natural gas is difficult to import, 80% to 85% of the United States natural gas demand in recent years has been supplied by domestic production. Imports from Canada have made up 10% to 15% of the United States natural gas needs and imports from a variety of other countries now make up for 1% to 2% of total supply in the form of liquefied natural gas, or LNG.

Situations involving over or under supply of natural gas can result in substantial price volatility. Continued concerns over the United States ability to meet its longer-term gas needs from declining domestic supply have resulted in sustained prices above $5.00 throughout 2003, 2004 and continuing into 2005. As a direct result of the strong commodity prices during 2004, we were able to increase our net income, generate substantial cash flows to fund acquisitions, our capital budget and repay borrowings on our revolving bank credit facility. However, historically, commodity prices have been very volatile, and we expect the volatility to continue in the future. As a result, we cannot accurately predict future natural gas and oil prices, and, therefore, we cannot determine what effect increases or decreases will have on our future revenues and cash flows. 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 our ability to access capital markets. Our continued growth and profitability depends on the strength of natural gas prices and our ability to acquire, find and develop new reserves at economical costs.

Critical Accounting Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make assumptions and prepare estimates that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities and revenues and expenses. We base our estimates on historical experience and various other assumptions that we believe are reasonable; however, actual results may differ. We evaluate our assumptions and estimates on a regular basis and discuss the development and disclosure process with our Audit Committee. See Note 1 - Summary of Organization and Significant Accounting Policies of Item 8 contained in this Form 10-K for a discussion of our significant accounting policies.

Proved Reserves. Our estimates of proved reserves are based on the quantities of natural gas and 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. However, there are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future revenues, rates of production and timing of development expenditures, including many factors beyond our control. The estimation process relies on assumptions and interpretations of available geologic, geophysical, engineering and production data and, the accuracy of reserve estimates is a function of the quality and quantity of available data, engineering and geological interpretation, and judgment. In addition, as a result of changing market conditions, commodity prices and future development costs will change from year to year, causing estimates of proved reserves to also change. For the years ended December 31, 2004 and 2003, we revised our proved reserves downward from prior years reports by approximately 20 Bcfe and 40 Bcfe, respectively, due to proved undeveloped reserves that were depleted or otherwise not recoverable, or from production performance indicating less gas in place or smaller reservoir size than initially estimated. Estimates of proved reserves are key components of our most significant financial estimates involving our unevaluated properties, our rate for recording depreciation, depletion and amortization and our full cost ceiling limitation. Our reserves are fully engineered on an annual basis by independent petroleum engineers.

Unevaluated Properties. The balance of unevaluated properties is comprised of capital costs incurred for undeveloped acreage, seismic data, wells and production facilities in progress, wells pending determination and related capitalized interest. These costs are initially excluded from our amortization base until the outcome of the project has been determined, or generally, until it is known whether proved reserves will or will not be assigned to the property. We assess all items in our unevaluated property balance on a quarterly basis for possible impairment or reduction in value. We believe that substantially all of the costs included in our unevaluated property balance will be evaluated in the next four years.

Asset Retirement Obligations. Asset retirement obligations represent the estimated future abandonment costs of tangible long-lived assets such as platforms, wells, service assets, pipelines, and other facilities. We estimate the fair value of an asset s retirement obligation in the period in which the liability is incurred, if a reasonable estimate can be made. We employ a present value technique to estimate the fair value of an asset retirement obligation, which reflects certain assumptions, including an inflation rate, our credit-adjusted, risk-free interest rate, the estimated settlement date of the liability and the estimated current cost to settle the liability which we compute from third party quotes. Changes in timing or to the original estimate of cash flows will result in changes to the carrying amount of the liability.

Derivative Instruments. Under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, as amended, we reflect the fair market value of our derivative instruments on our balance sheet. Our estimates of fair value are determined by obtaining independent market quotes from counterparties, as well as utilizing a Black-Scholes option valuation model that is based upon underlying forward price curve data, a risk-free interest rate and estimated volatility factors.

In addition to the critical estimates discussed above, estimates are used primarily in accounting and computing depreciation, depletion and amortization, the full cost ceiling, taxes, accruals of operating costs and production revenues, effectiveness of derivative instruments and fair value of stock options and related compensation expense.

New Accounting Pronouncements

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

On December 16, 2004, the FASB revised Statement 123 (revised 2004), Share-Based Payment that will require compensation costs related to share-based payment transactions (e.g., issuance of stock options and restricted stock) to be recognized in the financial statements. With limited exceptions, the amount of compensation cost will be measured based on the grant-date fair value of the equity or liability instruments issued. In addition, liability awards will be remeasured each reporting period. Compensation cost will be recognized over the period that an employee provides service in exchange for the award. Statement 123(R) replaces SFAS 123, Accounting for Stock-Based Compensation, and supersedes Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees. For us, SFAS 123(R) is effective for the first quarterly reporting period after June 15, 2005. Entities that use the fair-value-based method for either recognition or disclosure under SFAS 123 are required to apply SFAS 123(R) using a modified version of prospective application. Under this method, an entity records compensation expense for all awards it grants after the date of adoption. In addition, the entity is required to record compensation expense for the unvested portion of previously granted awards that remain outstanding at the date of adoption. In addition, entities may elect to adopt SFAS 123(R) using a modified retrospective method where by previously issued financial statements are restated based on the expense previously calculated and reported in their pro forma footnote disclosures.

On January 1, 2003, we adopted the fair value expense recognition provisions of SFAS 123 as amended by SFAS 148, Accounting for Stock-Based Compensation Transition and Disclosure using the prospective method as defined by the SFAS 148. As a result, we have recognized compensation expense for all stock options granted subsequent to January 1, 2003 with no expense recognized for grants made prior to 2003. Adoption of SFAS 123(R) will require us to recognize compensation expense over the remaining service period for the unvested portion of all options granted during 2000, 2001 and 2002. All options granted prior to 2000 are fully vested. We expect to adopt SFAS 123(R) on January 1, 2005, using the modified version of prospective application and are currently evaluating the effect of adopting SFAS 123(R).

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

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Overview of 2004 Results

The sustained strength of commodity prices throughout 2004 and production growth of 15% generated from all core operating areas were the primary factors behind results for operations, earnings and cash flows for 2004. The increase in our cash flows from operations allowed for increased capital spending from prior year levels for drilling and acquisitions and the repurchase and retirement of a portion of our common stock from KeySpan. During 2004:

We generated $162.8 million in net income, an increase of 24% from 2003;

We produced a total of 124 Bcfe and increased our average daily production rate by 15% to 339 MMcfe per day;

We increased total net proved reserves by 5% to 793 Bcfe with a standardized measure or after-tax discounted value of $1.4 billion;

We added 225 Bcfe of net proved reserves with 164 Bcfe added through the drill bit, 81 Bcfe added through acquisitions and incurred downward revisions due primarily to reservoir performance of 20 Bcfe;

We generated $522.4 million in net cash flows from operating activities and invested $517.0 million in natural gas and oil properties, which included $149.6 million for producing property acquisitions;

We drilled a record 211 wells, of which 177, or 84%, were successful with 56 successful wells in South Texas, 15 offshore, 73 in Arkoma, 28 in the Rockies and 5 in other areas;

We successfully integrated the Gulf of Mexico producing properties acquired in the fourth quarter of 2003 from Transworld Exploration and Production Inc., our largest acquisition to date, and, through the drilling and completion of 10 development wells, increased production from the acquired properties from an average of 30 MMcfe/day in December 2003 to more than 57 MMcfe/day in December 2004;

We divested our South Louisiana properties in February 2004, selling 12.3 Bcfe of net proved reserves for a net $13.1 million;

We divested our Appalachian Basin assets, in June 2004, as part of the KeySpan Exchange (see Note 3 Shareholders Equity), receiving an exchange value of $60.0 million for the properties that had estimated proved reserves of 51.2 Bcfe;

We assisted KeySpan in completing the divesture of its investment in our common stock, first with the KeySpan Exchange, in June 2004, whereby KeySpan s investment in our common stock was decreased from approximately 54% to 23% and finally, in November 2004, with the sale of their remaining 23% or 6,580,392 shares through a secondary public offering (see Note 3 Shareholders Equity *KeySpan Exchange and Offering* and *KeySpan Secondary Offering)*;

We expanded our Rocky Mountain acreage position in August 2004, which previously covered more than 200,000 net undeveloped acres throughout southwestern Montana, the Green River Basin of southwestern Wyoming and in the Uinta Basin of northeastern Utah, to include an additional 330,000 net acres in Colorado s DJ Basin where we have identified locations to drill approximately 100 wells during 2005;

We acquired two offshore blocks located in the central Gulf of Mexico from BP Exploration & Production Inc., in September 2004 for a net $30.0 million and added estimated proved reserves of 16.2 Bcfe and future exploitation opportunities (see Note 10 Acquisitions and Dispositions);

We acquired another 10 offshore blocks in October 2004, located primarily in the shallow waters of the central Gulf of Mexico, from Orca Energy, L.P and added an estimated 60.7 Bcfe of proved reserves and future exploitation opportunities for a net $113.6 million (see Note 10 Acquisitions and Dispositions);

We renegotiated our revolving bank credit facility in April 2004, and increased the maximum capacity from $350 million to $450 million, extended the maturity from July 2005 to April 2008 and by the end of December 31, 2004, after giving effect to acquisitions and dispositions, our borrowing base is $400 million;

We increased our outstanding borrowings under our revolving bank credit facility by a net $53 million, the majority of which was borrowed in the fourth quarter to fund our two producing property acquisitions;

We adopted a stockholder rights plan in October 2004, that is designed to assure that our stockholders receive fair and equal treatment in the event of an unsolicited takeover attempt and to protect against abusive or coercive takeover tactics that are not in the best interest of our company or its stockholders (see Note 3 Shareholders Equity *Stockholders Rights Plan)*; and

We announced our 2005 capital expenditure budget of $446 million, of which $445 million is expected to be spent for exploration and development activities.

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Operating and Financial Results for 2004 Compared to 2003 and Operating and Financial Results for 2003 Compared to 2002

	Year Ended December 31,				Year Ended December 31,			
Summary Operating Information:	**2004**	**2003**	**Variance**		**2003**	**2002**	**Variance**	
				(in thousands)				
Operating revenues	$ 650,439	$ 492,752	$ 157,687	32%	$ 492,752	$ 345,381	$ 147,371	43%
Operating expenses	382,626	294,157	88,469	30%	294,157	237,467	56,690	24%
Income from operations	267,813	198,595	69,218	35%	198,595	107,914	90,681	84%
Net income	162,824	131,040	31,784	24%	131,040	70,494	60,546	86%
Production:								
Natural gas (MMcf)	115,855	99,965	15,890	16%	99,965	97,368	2,597	3%
Oil (MBbls)	1,355	1,307	48	4%	1,307	859	448	52%
Total (MMcfe) (1)	123,985	107,807	16,178	15%	107,807	102,522	5,285	5%
Average daily production (MMcfe/d)	339	295	44	15%	295	281	14	5%
Average Sales Prices:								
Natural Gas (per Mcf) realized (2)	$ 5.17	$ 4.55	$ 0.62	14%	$ 4.55	$ 3.32	$ 1.23	37%
Natural Gas (per Mcf) unhedged	5.78	5.23	0.55	11%	5.23	3.16	2.07	66%
Oil (per Bbl) realized (2)	36.85	28.15	8.70	31%	28.15	23.99	4.16	17%
Oil (per Bbl) unhedged	36.85	28.46	8.39	29%	28.46	23.99	4.47	19%

(1) Mcfe is defined as one million cubic feet equivalent of natural gas, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

(2) Average realized prices include the effect of hedges.

Income from Operations

Production growth and higher realized natural gas prices were the primary factors contributing to our 35% increase in operating income in 2004 over 2003. Increased revenues were offset in part by a 30% increase in operating expenses.

Higher natural gas prices were the primary factor contributing to our 86% increase in net income and our 84% increase in operating income in 2003 over 2002. Adding to the effects of higher commodity prices realized in 2003 was an increase of 5% in production volume from 2002 levels. Increased revenues were offset in part by a 24% increase in operating expenses during 2003 due primarily to the continued expansion of our operations combined with an increase in costs to maintain our existing production base together with higher depreciation, depletion and amortization rates.

Production Volume 2004 vs. 2003

The 15% increase in production for 2004 is primarily a result of both production added from Gulf of Mexico properties acquired during the fourth quarter of 2003 as well as newly developed production, both onshore and offshore, from our existing property base.

Onshore. Daily production rates increased 8% from an average of 173 MMcfe per day in 2003 to 186 MMcfe per day in 2004, despite our loss of approximately 8 MMcfe per day as a result of the divesture of our South Louisiana and Appalachian Basin properties during the first half of 2004. The Arkoma Basin was our onshore growth area during 2004. We experienced the full impact of the accelerated drilling program initiated in 2003 that continued throughout

2004 as we added 15 MMcfe per day in newly developed production. With three rigs drilling through the first 10 months of 2004, Arkoma production reached a record of 44 MMcfe per day during the fourth quarter compared to 25 MMcfe per day during the fourth quarter of 2003. For 2004, South Texas production increased to an average of 142 MMcfe per day compared to 140 MMcfe per day 2003.

Average daily production rates for Arkoma and South Texas were negatively impacted during the quarter by our operational curtailment. As a result of rising rig rates and service costs during the fourth quarter of 2004, we reduced our onshore rig activity to keep capital spending within budgeted levels during the fourth quarter. In South Texas, we went

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from six rigs to four and in Arkoma we went from three rigs to one. In addition, we deferred the completion of seven wells in South Texas capable of producing an estimated 11 MMcfe per day, net, and five wells in Arkoma capable of producing an estimated 2 MMcfe per day, net. By the end of January 2005, we had resumed our six-rig program in South Texas and add a second rig in Arkoma. We expect to be able to add a third rig in Arkoma by the end of the first quarter 2005. As our South Texas properties begin to mature and production growth to minimize, our strategy will be to maintain production at existing levels while improving drilling and operating efficiencies.

In the Rockies, 2004 was an exploratory year and our activities were aimed at expanding our acreage position and proving up reserves in several exploration projects on our Uinta Basin acreage acquired in 2003. We drilled a total of 31 wells, 26 in the Uinta Basin, four in the DJ Basin and one in Montana. Of the total drilled, 28 wells or 90% were successful. By December 2004, six of our Uinta Basin wells were producing approximately 4 MMcfe per day, net to our interest. At December 31, 2004, production from the remaining 19 of our 25 successful Uinta Basin wells remained delayed, awaiting right-of-way approval for pipeline construction from the Bureau of Land Management (BLM). Subsequent to December 31, 2004, we received approval from the BLM for pipelines on 11 of the wells. We estimate initial production rates from these 11 wells, on a combined basis, to be approximately 8 MMcfe per day, net to our interests.

Offshore. We experienced record production growth as average daily rates increased 25% from 122 MMcfe per day during 2003 to an average of 153 MMcfe per day during 2004. We added approximately 41 MMcfe per day in newly developed production, of which an average of 22 MMcfe per day was attributable to development drilling at High Island A283 and East Cameron 56/57 and 148. During the year, we completed and brought on-line seven development wells at High Island A283, two at EC 56/57 and one at East Cameron 148. All of these fields were acquired in mid-October 2003, as part of our acquisition of Gulf of Mexico properties. Production from these properties accounted for approximately 71 MMcfe per day of our offshore production during 2004. Partially offsetting the production from our newly acquired properties were declines from existing and maturing fields totaling approximately 40 MMcfe per day, resulting in a net 31 MMcfe per day production increase year-over-year. Because the majority of our fields are located in the Western and Central Gulf of Mexico, Hurricane Ivan in September 2004, had minimal impact on our results for the year. We estimate that during the third quarter, approximately 210,000 or 2 MMcfe per day was deferred. All shut-in production was fully restored prior to the end of the third quarter of 2004.

During the fourth quarter of 2004, we experienced production declines at three key fields. In November 2004, the High Island 47 No. 1 well depleted. A third party operates this field and, our working interest is 33%. Prior to depletion, the well produced an average of 5 MMcfe per day to our interest, during 2004. In December 2004, our deep well at High Island 115, the No. 1, was shut-in due to a mechanical problem. A third party operates the well, and, we have a 50% working interest. During 2004, this well contributed an average of 9 MMcfe per day to our total daily production. We expect production to be restored during the third quarter of 2005. In late December 2004, our average daily production rate at High Island A283, dropped by an estimated 5 MMcfe/day from approximately 28 MMcfe/day as a result of the depletion on a pre-existing well and natural decline of newly developed wells.

Production Volume 2003 vs. 2002

The 5% increase in production for 2003 as compared to 2002, is primarily a result of newly developed production combined with additions from acquisitions made in 2003 and 2002.

Onshore. Daily production rates increased 12% from an average of 155 MMcfe/day during 2002 to 173 MMcfe/day during 2003. The increase in onshore production is primarily attributable to newly developed production in South Texas and Arkoma. In South Texas we drilled 56 successful wells and increased our average daily production rate to 140 MMcfe/day during 2003 from 123 MMcfe/day in 2002. In Arkoma, we more than doubled the number of wells drilled in 2002 by successfully drilling 46 wells during 2003. The impact of the newly developed production was seen in the fourth quarter of 2003 as our average daily rate in Arkoma increased to 25 MMcfe/day.

Offshore. Production decreased 3% from an average of 126 MMcfe/day during 2002 to an average of 122 MMcfe/day during 2003. For the first nine months of 2003, offshore production averaged 117 MMcfe/day as production declines due to maturing reservoirs from existing key fields, Mustang Island A-31/32, High Island 39, West Cameron 587 and South Marsh Island 253, were greater than new production added from wells and facilities brought on-line throughout 2003. Specifically, we had disappointing results at South Timbalier 314/317 that was brought on-line in early 2003. Contributing to the year-over-year production decline was the effect of shifting approximately $40 million of our 2002 offshore capital expenditure budget to our onshore region to fund the May 2002 acquisition of producing properties in South Texas from Burlington Resources. During the fourth quarter of 2003, offshore production increased by approximately 16% to an average rate of 136 MMcfe/day as we began to absorb the properties acquired from Transworld in mid-October and experienced production increases from newly developed fields, in particular, High Island 115 and High Island 47.

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Commodity Prices and Effects of Hedging 2004 vs. 2003

Our average unhedged or sales price for natural gas increased by 11% from $5.23 per Mcf during 2003 to $5.78 per Mcf during 2004. Included in natural gas revenues for 2004 is a loss of $70.1 million from natural gas hedging activities, which includes an unrealized loss of $1.9 million representing the ineffective portion of our derivative instruments that are not eligible for deferral under SFAS 133. The ineffectiveness was a result of changes during the period in the price differentials between the index price of the derivative contract, which uses a New York Mercantile Exchange (NYMEX) index, and the index price for the point of sale for the cash flow that is being hedged, the majority of which is the Houston Ship Channel index. As a result of the loss from hedging activities, we realized an average natural gas price during 2004 of $5.17 per Mcf that was 89% of or $0.61 lower than our average sales price. During 2003, we incurred a hedge loss from natural gas derivatives of $67.9 million, which is included in natural gas revenues and includes an unrealized loss of $1.9 million recognized for ineffectiveness, resulting in an average realized price of $4.55 per Mcf that was 87% of, or $0.68 per Mcf lower than our sales price.

Commodity Prices and Effects of Hedging 2003 vs. 2002

Our average wellhead price during 2003, before the effects of our hedging program, was $5.23 per Mcfe, up 66% over 2002. The increase in our natural gas and oil revenues was substantially offset by a $68.3 million loss from our hedging program, which lowered the price that we realized on our natural gas production by $0.68 Mcf during the period. The largest portion of this loss resulted from fixed price swaps for natural gas that we entered into during the fourth quarter of 2001 in connection with our acquisition of producing properties in South Texas. As a result of these swaps, we effectively fixed the price that we received on approximately 40 MMcf per day at $3.19, resulting in a loss of $32 million, or 47% of our total hedging loss for 2003.

For 2003, we realized an average natural gas price of $4.55 per Mcf, which was 87% of, or $0.68 per Mcf lower than our average unhedged natural gas price or wellhead price of $5.23 per Mcf for the period. Included in natural gas revenues is a loss of $67.9 million from natural gas hedging activities, which includes an unrealized loss of $1.9 million representing the ineffective portion of our derivative instruments that are not eligible for deferral under SFAS No. 133. For 2002, we realized an average gas price of $3.32 per Mcf, which was 105% of the average unhedged natural gas price of $3.16 per Mcf for the period. This resulted in natural gas revenues that were $16.4 million higher than the revenues we would have achieved if hedges had not been in place during the period. For 2002, our natural gas revenues included a realized gain of $16.4 million from hedging activities.

For 2003, we realized an average oil price of $28.15 per Bbl, which was 99% of or $0.31 per Bbl lower than the average unhedged price of $28.46 per Bbl for the period. As a result of oil hedging activities, oil revenues for 2003 were $0.4 million lower than the revenues we would have achieved if oil hedges had not been in place during the period. We had no oil hedges in place during 2002 and realized an average oil price of $23.99 per Bbl.

Operating Expenses

	Year Ended December 31,				Year Ended December 30,			
Operating Expenses per Mcfe	**2004**	**2003**	**Variance**		**2003**	**2002**	**Variance**	
Lease operating expense	$ 0.45	$ 0.44	$ 0.01	2%	$ 0.44	$ 0.33	$ 0.11	33%
Severance tax	0.10	0.15	(0.05)	-33%	0.15	0.09	0.06	67%
Transportation expense	0.10	0.10		%	0.10	0.09	0.01	11%
Asset retirement accretion expense	0.04	0.03	0.01	33%	0.03		0.03	100%
Depreciation, depletion and amortization	2.14	1.83	0.31	17%	1.83	1.67	0.16	10%

General and administrative, net	0.27	0.18	0.09	50%	0.18	0.13	0.05	38%
Total operating expenses per unit of production	$ 3.10	$ 2.73	$ 0.37	14%	$ 2.73	$ 2.31	$ 0.42	18%

Total operating expenses in 2004 increased 30% over 2003 driven primarily by higher depreciation, depletion and non-recurring general and administrative expenses. On a unit production basis, operating expenses increased $0.37 per Mcfe produced, or 14%, over 2003. Depreciation, depletion and amortization accounted for $0.31 of the increase and the additional general and administrative expenses contributed $0.08 per Mcfe. Severance tax was $0.05 per Mcfe lower primarily as a result of exemptions in South Texas due to our high-cost/tight-gas formation designation.

Lease Operating Expense. On an absolute dollar basis, lease operating expense increased by 19% during 2004. This increase relates primarily to our integration of offshore Gulf of Mexico properties that we acquired during the fourth quarter of 2003. These properties originally carried a relatively high operating cost and we are working to bring the cost structure of these properties more into line with our base offshore properties. Although lease operating expense was up in absolute terms in 2004, on a per unit of production basis taking into account our 15% increase in production, lease operating expense increased by only 2% or $0.01 in 2004. While we remain committed to minimizing our operating cost structure, in light of increasing service costs and our continued acquisition activities, we expect to experience upward pressure in our lease operating expense during 2005 and beyond.

During 2003, the increase in lease operating expenses as compared to 2002 is attributable to the continued expansion of our operations both onshore and offshore. Our overall operating expenses are increasing as we add new wells and production facilities and continue to maintain production from existing, maturing properties. Specific increases for 2003 were incurred for production enhancement and compression, insurance and contract services. In addition, we incurred $2.6 million in non-recurring expenses associated with workovers.

The acquisition of the Transworld properties in October 2003 caused our lease operating expense on a per unit basis to increase from an average of $0.42 per Mcfe for the first nine months of 2003 to $0.47 per Mcfe during the fourth quarter of 2003. The majority of the Transworld fields were originally developed by major oil and gas producers and due to their age and complexity, lease operating expenses for these properties are expected to be significantly higher than that of our existing offshore fields.

Severance Tax. Severance tax is a function of volume and revenues generated from onshore production. On an absolute dollar basis, severance tax decreased by 25% from 2003 to 2004. On an Mcfe basis, severance tax decreased by $0.05 or 33% for the twelve-month period. Despite higher wellhead prices during 2004, severance tax expense is lower primarily due to severance tax rebates received late in 2004 on our South Texas properties as a result of their high-cost/tight-sand designation.

For 2003, the increase in severance tax expense and severance tax per Mcfe is due to a 66% increase in average wellhead prices for natural gas during 2003 combined with a 12% increase in onshore production as compared to 2002.

Depreciation, Depletion and Amortization. The increase in our depreciation, depletion and amortization expense for 2004 was primarily a result of a higher depletion rate combined with a 15% increase in production for the year. Our depletion rate of $2.14 per Mcfe during 2004 was 17% higher than the $1.83 per Mcfe during 2003. Higher average finding costs per unit were the primary factor in the increase in our depletion rate. These higher finding costs are the result of the naturally declining productivity of our mature onshore drilling operations compounded by increasing service costs. Rising acquisition prices resulting from the continued strength of natural gas prices were also a factor. In addition, our estimated future development costs at December 31, 2004 increased 48% from estimates at December 31, 2003, primarily as a result of the future development costs relating to several offshore Gulf of Mexico properties acquired in October 2004. For 2004, producing property dispositions resulted in reserve reductions of 63.3 Bcfe. Finally, for 2004, we incurred downward revisions of 20 Bcfe, either due to proved undeveloped reserves that were depleted or otherwise not recoverable, or from production performance indicating less gas in place or smaller reservoir size than initially estimated.

During 2003, the increase in our DD&A expense was primarily a result of a higher depletion rate combined with a 5% increase in production volumes for 2003. Our depletion rate increased during 2003 as a result of downward reserve revisions related to reservoir performance of approximately 40 Bcfe; the addition of more costs to our depreciation base with fewer additions for reserves as our average finding and development cost increased during 2003; and a 52% increase in our estimated future development costs at year end, the majority of which was due to the proved undeveloped classification of 68% of the reserves acquired from Transworld.

Asset Retirement Accretion Expense. The increase in ARO accretion expense during 2004 as compared to 2003, is primarily a result of additions to our ARO liability since the end of the third quarter of 2003 as a result of producing property acquisitions, offset in part by the disposition of our South Louisiana properties in February 2004 and our Appalachian Basin properties in June 2004.

General and Administrative Expenses, Net of Overhead Reimbursements and Capitalized General and Administrative Expenses

	Year Ended December 31,				**Year Ended December 31,**			
General and Administrative per Mcfe	**2004**	**2003**	**Variance**		**2003**	**2002**	**Variance**	
Gross general and administrative expense	$ 0.40	$ 0.32	$ 0.08	25%	$ 0.32	$ 0.28	$ 0.04	14%
Operating overhead reimbursements	(0.01)	(0.02)	0.01	-50%	(0.02)	(0.02)		%
Capitalized general and administrative	(0.12)	(0.12)		%	(0.12)	(0.13)	0.01	-8%
General and administrative expense, net	$ 0.27	$ 0.18	$ 0.09	50%	$ 0.18	$ 0.13	$ 0.05	38%

2004 vs. 2003. For 2004, net general and administrative expenses were up by 69% on an absolute dollar basis from $19.5 million in 2003 to $32.9 million in 2004. Of the $13.4 million increase, $9.5 million related to severance expenses and special incentive payments. A substantial portion of the remaining increase related to changes in accounting for stock-based compensation, as well as continuing professional expenses related to corporate governance compliance. Specifically, $4.1 million of the increase related to special bonuses awarded by our Board to 12 key employees, including our Chief Executive Officer who received $3.2 million, who assisted in structuring and consummating the KeySpan Exchange and Offering completed in June 2004 (see Note 3 Stockholders Equity *KeySpan Exchange and Offering*). Approximately $0.3 million related to accelerated vesting of restricted stock held by directors who resigned or retired from our Board in June following the KeySpan Exchange. Lastly, approximately $5.1 million related to executive severance accrued with respect to three senior executives with rights to receive severance, accelerated vesting of options and restricted stock, and other benefits under their employment agreements as a result of an organizational realignment of management responsibilities during the fourth quarter of 2004. One executive resigned effective December 14, 2004 and two executives resigned effective March 1, 2005.

For general and administrative expense on a per-unit of production basis, the additional compensation expenses of $9.5 million resulted in an $0.08 per Mcfe increase for 2004. Absent these additional compensation expenses, gross general and administrative expense for 2004 would have been $0.32 per Mcfe, unchanged from $0.32 per Mcfe in 2003 and net general and administrative expense would have been $0.19 per Mcfe for 2004, an increase of $0.01 or 6%, from 2003. While general and administrative expenses have increased as our company has grown, per unit expense is comparable year-over-year as a result of the increase in our production volume during 2004.

2003 vs. 2002. The increase in aggregate general and administrative expense during 2003 was due primarily to the expansion of our workforce that corresponds to the continued expansion of our operations. As our workforce expands, we have experienced an increase in salaries and related employee benefit expenses that include increases in our incentive compensation expense together with expense for stock compensation as we adopted the fair value expense provisions for stock options under SFAS 123, as amended, in January 2003. Our rent expense increased as we expanded our leased office space in downtown Houston to accommodate our growing workforce and opened an office in Denver to coordinate our expansion into the Rocky Mountains. Our legal, audit and accounting expenses increased as we implemented new corporate governance policies required by the Sarbanes-Oxley Act of 2002 and engaged an outside firm to perform ongoing internal auditing functions.

The higher rate per Mcfe during 2003 reflects the increase in our aggregate general and administrative expenses combined with a proportional reduction in the amount of general and administrative expense capitalized during 2003. The mix of our capitalized expenses has changed as we incurred more costs during 2003 that were not directly related to our natural gas and oil exploration and development activities. We expect that as our company continues to grow and expand, our general and administrative expenses will increase.

Other Income and Expense, Interest and Taxes

Other Income and Expense. For 2004, Other Income and Expense includes two items: (i) income of $1.0 million related to refunds of prior year s severance tax expense; and (ii) a $0.2 million write-off of a portion of our debt issuance costs due to the June 2, 2004 reduction in the borrowing base on our revolving bank credit facility due to the disposition of our Appalachian Basin assets in June 2004. In July 2002, we applied for and received from the Railroad Commission of Texas a high-cost/tight-gas formation designation for a portion of our South Texas production. For qualifying wells, production is either exempt from tax or taxed at a reduced rate until certain capital costs are recovered. For 2004, the recognition of other income as a result of the recoupment of prior years expense is considerably less than in 2003 as we are nearing the end of the recoupment process. For 2003, Other Income and Expense includes: (i) debt extinguishment expenses totaling $5.9 million incurred pursuant to the call and early redemption of our $100 million 8 5/8% senior subordinated notes due 2008; and (ii) income of $21.6 million related to refunds of prior year s severance tax expense. In 2002, we recognized as other income, $9.1 million related to the recoupment of prior years severance tax expense.

Interest and Average Borrowings	Year Ended December 31, 2004	2003	Variance		Year Ended December 31, 2003	2002	Variance	
	(in thousands)							
Gross interest	$ 17,813	$ 15,642	$ 2,171	14%	$ 15,642	$ 15,373	$ 269	2%
Capitalized interest	(8,358)	(7,300)	(1,058)	14%	(7,300)	(7,975)	675	-8%
Interest expense, net of capitalized interest	$ 9,455	$ 8,342	$ 1,113	13%	$ 8,342	$ 7,398	$ 944	13%
Average borrowings	$ 289,410	$ 240,000	$ 49,410	-21%	$ 240,000	$ 263,600	$ (23,600)	-9%
Average interest rate	5.68%	6.08%	0.40%	-7%	6.08%	5.38%	0.70%	13%

Interest Expense, Net of Capitalized Interest. For 2004, the increase in gross interest expense is due to an increase in both fixed debt and bank debt offset in part by a decrease in average interest rates. Our fixed debt increased in June 2003 when we replaced our existing senior subordinated notes of $100 million at 8 5/8% with new senior subordinated notes of $175 million at 7%. Bank borrowings averaged $112 million at a rate if 3.74% during 2004 compared to an average of $90 million at 3.42% during 2003. Bank debt has increased as we utilized our revolving bank credit facility to fund not only a portion of the KeySpan Exchange in June 2004 but also our two producing property acquisitions in September and October 2004. Although the majority of our bank debt is at LIBOR rates, we do expect to see an increase in rates during 2005 if, based on our belief, the Federal Reserve continues its expected plan to slowly increase interest rates in an effort to curb inflation. Rates were increased in February 2005, by one quarter of a percent. Capitalized interest is a function of unevaluated properties and the increase for 2004 corresponds to the increase in our average unevaluated property balance throughout 2004.

During 2003, our average borrowings decreased and our average interest rate increased as we replaced our existing fixed debt of $100 million at 8 5/8% with new fixed debt of $175 million at 7% and used excess proceeds from the newly issued debt to repay outstanding borrowings under our revolving bank credit facility which bears interest at lower rates that averaged 3.4% during both 2003 and 2002. Bank borrowings averaged $90 million at a rate if 3.42% during 2003 compared to an average of $162.2 million at 3.42% during 2002. In addition, capitalized interest decreased during 2003. Our capitalized interest is a function of unevaluated properties and the decrease corresponds to the decrease in our average unevaluated property balance throughout 2003 prior to our October 2003 acquisition of producing properties from Transworld.

Income Tax Provision. Our provision for taxes includes both state and federal taxes. For the current year, our state tax obligations have increased as our onshore revenues have increased and as we have expanded our operations into several Rocky Mountain states. The 34% increase in income taxes for 2004 corresponds to the 26% increase in income before taxes. Our current provision increased to $41.2 million as we utilized all of our net operating loss carryforwards during 2003 and moved to a tax paying status. Prior to the third quarter of 2003, the majority of our federal income taxes were deferred. Our current provision for 2004 includes $1.4 million relating to nondeductible excess executive compensation expense of which $1.0 million was incurred in the second quarter as a result of the special bonus paid to our Chief Executive Officer in connection with the KeySpan Exchange and $0.4 million incurred in the fourth quarter as a result of the retirement of our former Senior Vice President and General Manager Offshore Division.

During 2003, our current provision increased to $12.5 million as we depleted our net operating loss carryforwards and moved to a tax paying status where, as in prior years, all federal and state income taxes were deferred.

Liquidity

Capital Requirements

Our principal requirements for capital are to fund our capital investment program and to satisfy our contractual obligations, primarily the repayment of long-term debt. Our capital investments include the following:

Costs of acquiring and maintaining our lease acreage position and our seismic resources;

Costs of drilling and completing new natural gas and oil wells;

Costs of acquiring additional reserves;

Costs of installing new production infrastructure;

Costs of maintaining, repairing, and enhancing existing natural gas and oil wells;

Costs related to plugging and abandoning unproductive or uneconomic wells; and

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Indirect costs related to our exploration activities, including payroll and other expense attributable to our exploration professional staff.

Our capital expenditure budget for 2005 has been set at an initial level of $445 million. We are the designated operator of approximately 77% of our wells. Operating allows us the ability to exercise control over the magnitude and timing of our capital program and provides us significant latitude to increase or decrease our spending in response to changes in price, operational developments or acquisition opportunities. To maintain flexibility of our capital program, we do not enter into material long-term obligations with any of our drilling contractors or service providers with respect to our operated properties. We do not include property acquisition costs in our capital budget because the size and timing of capital requirements for acquisitions are inherently unpredictable. As the year progresses, we will continue to evaluate our capital spending. Actual levels may vary due to a variety of factors, including drilling results, natural gas prices, economic conditions and future acquisitions.

Total company capital expenditures during 2004 were $518.5 million. We invested $517.0 million in natural gas and oil properties, which included $149.6 million for the acquisition of producing properties and, we spent $1.5 million for non-oil and gas property and equipment. Non-oil and gas property and equipment includes expenditures to upgrade to our information technology systems and office equipment and compares to $1.9 million spent in 2003. For 2004, we spent 53% offshore and 42% onshore with the balance of 5% on capitalized interest and general and administrative costs. We completed the drilling of a record 211 gross wells (170.5 net) of which 84% or 177 (143.5 net) were successful and 34 (27.0 net) were unsuccessful with an additional 25 wells (21.2 net) in progress at the end to the year. The table below provides a five-year historical analysis of our capital expenditures for natural gas and oil properties and total net proved reserve additions, that is defined as the sum of reserve extensions and discoveries, revisions and acquisitions. See Note 12 Supplemental Information On Natural Gas and Oil Exploration, Development and Production Activities for a detail calculation of the changes in our reserve quantities during the period.

	Years Ended December 31,				
	2004	**2003**	**2002**	**2001**	**2000**
	(in thousands)				
Natural gas and oil capital expenditures					
Producing property acquisitions	$ 149,599	$ 175,420	$ 73,351	$ 69,010	$ 13,935
Leasehold and lease acquisition costs (1)	57,741	56,076	36,458	48,068	32,599
Development	245,971	162,235	122,036	177,256	103,335
Exploration	63,646	66,259	26,536	72,056	34,160
Total natural gas and oil capital expenditures	516,957	459,990	258,381	366,390	184,029
Producing property dispositions	(72,712)		(5,309)		
Net natural gas and oil capital expenditures	$ 444,245	$ 459,990	$ 253,072	$ 366,390	$ 184,029
Proved reserve additions, net of revisions (MMcfe)	225,633	212,969	144,291	136,231	100,352

(1) For 2004, 2003, 2002, 2001 and 2000, leasehold costs include capitalized interest and general and administrative expenses of $23.2 million, $20.2 million, $21.1 million, $24.9 million and $23.3 million, respectively.

Future Commitments

In addition to our capital expenditure program, we are committed to making cash payments in the future on two types of contracts: note agreements and operating leases. As of December 31, 2004, we do not have any capital leases or have we entered into long-term contracts for drilling rigs or equipment. As of December 31, 2004, we do not have off-balance sheet debt or other such unrecorded obligations, and we have not guaranteed the debt of any other party. The table below provides estimates of the timing of future payments that we were obligated to make based on agreements in place at December 31, 2004. In addition to the contractual obligations listed on the table below, our balance sheet at December 31, 2004, reflects accrued interest payable on our revolving bank credit facility of approximately $92,000 which is payable over the next 90-day period. We expect to make annual interest payments of $12.3 million per year on our $175 million of 7% senior subordinated notes due June 2013. And, we anticipate making income tax payments of approximately $50 million 2005.

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			As of December 31, 2004 Payments Due by Period			
	Reference	Total	1 year or less	2 3 years	4 5 years	after 5 years
			(in thousands)			
Contractual Obligations:						
Revolving bank credit facility, due April 2008	Note 2	$ 180,000	$	$	$ 180,000	$
7% senior subordinated notes, due June 2013	Note 2	175,000				175,000
Derivative instruments	Note 7	75,149	68,081	5,551	1,517	
Operating leases	Note 9	7,223	1,550	3,129	2,544	
Lump sum payments employment contracts	Note 6	2,150	2,150			
		439,522	71,781	8,680	184,061	175,000
Other Long-Term Obligations:						
Asset retirement obligations	Note 1	91,746	662	9,813	6,771	74,500
Total contractual obligations and commitments		$ 531,268	$ 72,443	$ 18,493	$ 190,832	$ 249,500

Capital Resources

We intend to fund our capital expenditure program and contractual commitments through cash flows from our operations and borrowings under our revolving bank credit facility. If a significant acquisition opportunity arises, we may also access public markets for debt or to issue additional equity securities. Our primary sources of cash during 2004 were from funds generated from operations. Cash was used to fund acquisitions, exploration and development expenditures and to reduce debt under our revolving bank credit facility. We made aggregate cash payments of $16.4 million and $41.8 million, respectively, for interest and taxes during 2004. The table below summarizes the sources of cash during 2004 and 2003.

	Years Ended December 31,			
	2004	2003	variance	% change
	(in thousands)			
Net cash provided by operating activities	$ 522,436	$ 390,832	$ 131,604	34%
Net cash used for investments in property and equipment	505,217	461,822	43,395	9%
Net cash (used in) provided by financing activities	(1,211)	55,528	(56,739)	-102%
Net (decrease) increase in cash	$ 16,008	$ (15,462)	$ 31,470	-204%

At December 31, 2004, we had a working capital deficit of $31.9 million, long-term debt of $355 million and $219.6 million of borrowing capacity available under our revolving bank credit facility. The working capital deficit at December 31, 2004, was due to a current liability of $68.1 million representing the fair value of our derivative instruments estimated to be payable over the next 12 months. The fair value of our derivative instruments will fluctuate with commodity prices, and as commodity prices increase, our liquidity exposure tends to increase as a result of open derivative instruments. Consequently, we are more likely to have the largest unfavorable mark-to-market position in a high commodity price environment. Our working capital balance fluctuates as a result of the timing and amount of cash receipts and disbursements for operating activities and borrowings or repayments under our revolving bank credit facility. As a result, we often have a working capital deficit or a relatively small amount of positive working capital, which is typical of companies of our size in the exploration and production industry.

The 34% increase in net cash provided by operating activities during 2004 was primarily attributable to the increase in net income as a result of a 14% increase in average realized natural gas price, which included the effect of hedges, together with a 15% increase in production volume, offset in part by a 30% increase in operating expenses. Fluctuations in operating assets and liabilities are caused by the timing of cash receipts and disbursements.

During 2004, total long-term debt increased by a net $53 million, as we borrowed to finance a portion of the KeySpan Exchange and to fund the two producing property acquisitions made in September and October of 2004. We used net proceeds of $282 million generated from the public offering of 6,820,000 shares of our common stock plus bank borrowings of $107 million to fund the $389 million cash portion of the KeySpan Exchange whereby we redeemed and cancelled 10,800,000 of our shares held by KeySpan with cash value of $310.7 million.

Access to Capital Markets. In March 2004, we filed a shelf registration statement with the SEC for the offering, from time to time, of up to $600 million of our common stock, preferred stock, depositary shares and debt securities, or a combination of any of these securities, as well as for all the shares of our common stock owned at that time by KeySpan. Subsequent to the June 2004 public offering of 6.8 million shares at $48.00 per share, the proceeds of which were used to finance a portion of the KeySpan Exchange transaction, we have approximately $272.5 million of capacity remaining under this shelf registration statement. On October 27, 2004, we filed a second shelf registration statement with the SEC for the offering, from time to time, of up to an additional $477.5 million of our equity or debt securities. The combination of the two shelf registrations statements provides an aggregate of approximately $750 million for the offering of our common stock, preferred stock, depositary shares and debt securities, or a combination of any of these securities.

We believe that operating cash flow and our credit facility will be adequate to meet our capital and operating requirements for 2005. We continuously monitor our working capital and debt position as well as coordinate our capital expenditure program with expected cash flows and projected debt repayment schedules. Although we have no specific budget for future property acquisitions, should attractive opportunities arise, we believe we could finance the additional capital expenditures with cash on hand, operating cash flow, additional borrowing under our revolving bank credit facility, issuances of additional equity or debt securities or development with industry partners.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements to enhance liquidity and capital resource positions, or for any other purpose. Any future transactions involving off-balance sheet arrangements would be scrutinized and disclosed.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Market Risk

Our major market risk exposure continues to be the prices applicable to our natural gas and oil production. Our sales price is primarily driven by the prevailing market price. Historically, prices received for our natural gas and oil production have been volatile and unpredictable.

Interest Rate Market Risk

At December 31, 2004, total debt was $355 million, of which approximately 49% or $175 million is fixed at an interest rate of 7%. The remaining 51% of our total debt balance at December 31, 2004, or $180 million, represents our bank debt that is tied to floating or market interest rates. Fluctuations in floating interest rates will cause our annual interest costs to fluctuate. During the fourth quarter of 2004, the interest rate on our outstanding bank debt averaged 4.22%. If the balance of our bank debt at December 31, 2004, were to remain constant, a 10% change in market interest rates would impact our cash flow by an estimated $195,000 per quarter.

Commodity Risk

We utilize derivative commodity instruments to hedge future sales prices on a portion of our natural gas and oil 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 investment grade financial institutions that we believe are minimal credit risks. We believe that our credit risk related to our natural gas futures and swap contracts is no greater than the risk associated with the primary contracts and that the elimination of price risk reduces volatility in our reported results of operations, financial position and cash flows from period to period and lowers our overall business risk; however, as a result of our hedging activities we may be exposed to greater credit risk in the future.

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 unrealized gains or losses, net of tax, 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 natural gas and oil revenues. During both 2004 and 2003, we recognized $1.9 million in each year for ineffectiveness. The ineffectiveness was primarily a result of changes at the end of the current period in the price differentials between the index price of the derivative contract, which uses a NYMEX index, and the index price for the point of sale for the cash flow that is being hedged, the majority of which is the Houston Ship Channel index.

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Changes in Fair Value of Derivative Instruments

The following table summarizes the change in the fair value of our derivative instruments for each of the twelve-month periods from January 1 to December 31, 2004 and 2003 and provides the fair value at the end of each period.

Change in Fair Value of Derivatives Instruments:	Year Ended December 31, 2004 Before Tax	Year Ended December 31, 2003 Before Tax
	(in thousands)	
Fair value of contracts at January 1	$ (36,862)	$ (38,772)
Realized loss on contracts settled	68,195	66,408
Fair value of new contracts when entered into		5,288
(Decrease) in fair value of all open contracts	(106,482)	(69,786)
Net (decrease) increase during period	(38,287)	1,910
Fair value of contracts outstanding at December 31	$ (75,149)	$ (36,862)

Derivatives in Place as of the Date of Our Report

As of February 22, 2005, the following table summarizes, on an annual basis, our natural gas hedges in place for 2005, 2006, 2007 and 2008. For 2005, we have hedged approximately 70% of our estimated production or a total of 260,000 million British thermal units per day or MMBtu/day and, our ceiling will average $6.086/MMBtu and our floor will average $4.978/MMBtu. For 2006, we have hedged approximately 67% of our estimated production or a total of 250,000 MMBtu/day with an average ceiling of $6.946/MMBtu and average floor of $5.788/MMBtu.

Natural Gas Hedges		Fixed Price Swaps		Collars		
		Daily Volume	NYMEX Contract	Daily Volume	NYMEX Contract Price (1)	
Period		(MMBtu)	Price	(MMBtu)	Floor	Ceiling
January	December 2005	80,000	$ 5.304	180,000	$ 4.833	$ 6.434
January	December 2006	30,000	5.893	220,000	5.788	6.946
January	December 2007			30,000	5.000	6.597
January	December 2008			20,000	5.000	5.720

(1) For collars, price represents a weighted average for outstanding contracts.

For natural gas, 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 mark-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.

Item 8. Financial Statements and Supplemental Data

For financial statements required by Item 8, see Item 15 in Part IV of this Annual Report.

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

None.

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Item 9A. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we conducted an evaluation of our disclosure controls and procedures, as this term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act). Based on this evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures were effective as of the end of the period covered by this Annual Report.

Design and Evaluation of Internal Control Over Financial Reporting

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, we have included a report of management s assessment of the design and effectiveness of its internal controls as part of this Annual Report on Form 10-K for the fiscal year ended December 31, 2004. Deloitte and Touche LLP, our independent public accountants, also attested to, and reported on, management s assessment of the effectiveness of internal control over financial reporting. Management s report and the independent registered public accounting firm s attestation report are included in our 2004 Financial Statements in Item 15 under the captions entitled Management s Report on Internal Control Over Financial Reporting and Report of Independent Registered Public Accounting Firm and are incorporated herein by reference.

Changes in Internal Control Over Financial Reporting

No change in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) occurred during the fourth quarter of our fiscal year ended December 31, 2004 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

None.

Part III.

Item 10. Directors and Executive Officers of Houston Exploration

The information required by Item 10 that relates to our directors and executive officers is incorporated by reference from the information appearing under the captions Election of Directors, Executive Officers, Board Committees Audit Committee, Board Committees Nominating and Corporate Governance Committee and Compliance with Section 16(a) in our definitive proxy statement that is to be filed with the SEC pursuant to the Exchange Act within 120 days of the end of our fiscal year on December 31, 2004.

Item 11. Executive Compensation

The information required by Item 11 that relates to compensation of our principal executive officers and our directors 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 that is to be filed with the SEC within 120 days of the end of our fiscal year on December 31, 2004. In addition and in accordance with Item 402(a)(8) of Regulation S-K, the information contained in our definitive 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 Annual Report. For information concerning our code of ethics, see Item 1. and 2. Business and Properties Available Information.

Item 12. Security Ownership of Beneficial Owners and Management

The information required by Item 12 that relates to the ownership of securities by management and others is incorporated by reference from the information appearing under the caption Securities Authorized for Issuance Under Equity Compensation Plans and Security Ownership of Certain Beneficial Owners and Management in our definitive proxy statement that is to be filed with the SEC within 120 days of the end of our fiscal year on December 31, 2004.

Item 13. Certain Relationships and Related Transactions

The information required by Item 13 that relates to business relationships and transactions with our management and other related parties is incorporated by reference from the information appearing under the captions Certain Relationships and Related Party Transactions and Compensation Committee Interlocks and Insider Participation in our definitive proxy statement that is to be filed with the SEC within 120 days of the end of our fiscal year on December 31, 2004.

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Item 14. Principal Accounting Fees and Services

The information required by Item 14 that relates to services provided by our Independent Public Accountants and the fees incurred for services provided during 2004 and 2003 is incorporated by reference from the information appearing under the captions Fees Billed by Independent Public Accountants in our definitive proxy statement that is to be filed with the SEC within 120 days of the end of our fiscal year on December 31, 2004.

Part IV.

Item 15. Exhibits, Financial Statement Schedules

(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:

(a) See Index of Exhibits on page F-38 for a description of the exhibits filed as a part of this report.

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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: February 22, 2005

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POWER OF ATTORNEY

Each person whose signature appears below hereby constitutes and appoints John H. Karnes and James F. Westmoreland, and each of them, his true and lawful attorney-in-fact and agent, with full powers of substitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report of Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission granting to said attorneys-in-fact, and each of them, full power and authority to perform any other act on behalf of the undersigned required to be done in connection therewith.

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	Chairman of the Board of Directors, President and Chief Executive Officer (Principal Executive Officer)	February 22, 2005
/s/ John H. Karnes John H. Karnes	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 22, 2005
/s/ James F. Westmoreland James F. Westmoreland	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 22, 2005
/s/ Robert B. Catell Robert B. Catell	Director	February 22, 2005
/s/ John U. Clarke John U. Clarke	Director	February 22, 2005
/s/ David G. Elkins David G. Elkins	Director	February 22, 2005
/s/ Harold R. Logan, Jr. Harold R. Logan, Jr.	Director	February 22, 2005
/s/ Thomas A. McKeever Thomas A. McKeever	Director	February 22, 2005
/s/ Stephen W. McKessy Stephen W. McKessy	Director	February 22, 2005
/s/ Donald C. Vaughn Donald C. Vaughn	Director	February 22, 2005

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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.

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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. In addition, please refer to the definitions of proved oil and gas reserves as provided in Rule 4-10(a)(2)(3)(4). The rule is available at the SEC web site, http://www.sec.gov/divisions/corpfin/forms/regsx.htm#gas.

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 natural gas or oil 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.

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Board of Directors and Stockholders of
The Houston Exploration Company

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

Based on Houston Exploration s evaluation under the framework in *Internal Control Integrated Framework*, our principal executive officer and principal financial officer concluded that internal control over financial reporting was effective as of December 31, 2004. The conclusion of our principal executive officer and principal financial officer is based on the recognition that there are inherent limitations in all systems of internal control. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the polices or procedures may deteriorate. Management s assessment of the effectiveness of internal control over financial reporting as of December 31, 2004 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein.

The Houston Exploration Company
Houston, Texas
February 22, 2005

/s/ William G. Hargett	/s/ John H. Karnes
William G. Hargett Chairman, President and Chief Executive Officer	John H. Karnes Senior Vice President and Chief Financial Officer

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
The Houston Exploration Company
Houston, Texas

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

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

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

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

We have also audited, in accordance with the Standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2004 of the Company and our report dated February 22, 2005 which report expresses an unqualified opinion and includes an explanatory paragraph relating to the adoption of Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations, and SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure, on January 1, 2003.

DELOITTE & TOUCHE LLP

Houston, Texas
February 22, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
The Houston Exploration Company
Houston, Texas

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 22, 2005 expressed an unqualified opinion on management s assessment of the effectiveness of the Company s internal control over financial reporting and an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

As discussed in Note 1 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations, and SFAS No. 148, Accounting for Stock-Based Compensation-Transition and Disclosure, on January 1, 2003.

DELOITTE & TOUCHE LLP

Houston, Texas
February 22, 2005

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THE HOUSTON EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

	December 31, 2004	December 31, 2003
Assets:		
Cash and cash equivalents	$ 18,577	$ 2,569
Accounts receivable	103,069	87,949
Accounts receivable Affiliate		6,733
Derivative financial instruments		3,458
Inventories	976	1,071
Deferred tax asset	24,101	19,644
Prepayments and other	9,107	5,818
Total current assets	155,830	127,242
Natural gas and oil properties, full cost method		
Unevaluated properties	122,691	134,491
Properties subject to amortization	2,777,097	2,324,011
Other property and equipment	11,740	12,617
	2,911,528	2,471,119
Less: Accumulated depreciation, depletion and amortization	1,363,272	1,099,990
	1,548,256	1,371,129
Other non-current assets	18,491	10,694
Total Assets	$ 1,722,577	$ 1,509,065
Liabilities:		
Accounts payable and accrued expenses	$ 118,971	$ 83,983
Derivative financial instruments	68,081	35,592
Asset retirement obligation	662	7,703
Total current liabilities	187,714	127,278
Long-term debt and notes	355,000	302,000
Derivative financial instruments	7,068	4,728
Deferred federal income taxes	288,069	251,425
Asset retirement obligation	91,084	84,654
Other deferred liabilities	10,722	3,446
Total Liabilities	939,657	773,531

Commitments and Contingencies (see Note 9)		
Stockholders Equity:		
Preferred Stock, $0.01 par value, 5,000,000 shares authorized and no shares issued		
Common Stock, $.01 par value, 50,000,000 shares authorized and 28,380,207 and 31,437,581 shares issued and outstanding at December 31, 2004 and 2003, respectively	284	315
Additional paid-in capital	273,002	366,781
Unearned compensation	(2,537)	(808)
Retained earnings	558,198	395,374
Accumulated other comprehensive income	(46,027)	(26,128)
Total Stockholders Equity	782,920	735,534
Total Liabilities and Stockholders Equity	$ 1,722,577	$ 1,509,065

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

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THE HOUSTON EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

	For the Years Ended December 31, 2004	2003	2002
Revenues:			
Natural gas and oil revenues	$ 649,087	$ 491,440	$ 344,295
Other	1,352	1,312	1,086
Total revenues	650,439	492,752	345,381
Operating expenses:			
Lease operating	55,925	47,072	33,976
Severance tax	11,933	15,958	9,487
Transportation expense	11,819	10,387	9,317
Asset retirement accretion expense	4,902	3,668	
Depreciation, depletion and amortization	265,148	197,530	171,610
General and administrative, net of amounts capitalized	32,899	19,542	13,077
Total operating expenses	382,626	294,157	237,467
Income from operations	267,813	198,595	107,914
Other (income) expense	(1,058)	(15,746)	(9,070)
Interest expense, net of amounts capitalized	9,455	8,342	7,398
Income before income taxes	259,416	205,999	109,586
Provision for taxes	96,592	72,187	39,092
Income before cumulative effect of change in accounting principle	$ 162,824	$ 133,812	$ 70,494
Cumulative effect of change in accounting principle		(2,772)	
Net income	$ 162,824	$ 131,040	$ 70,494
Earnings per share:			
Net income per share basic			
Income before cumulative effect of change in accounting principle	$ 5.50	$ 4.30	$ 2.31
Cumulative effect of change in accounting principle		(0.09)	¾
Net income per share basic	$ 5.50	$ 4.21	$ 2.31
Net income per share diluted			

Income before cumulative effect of change in accounting principle	$ 5.44	$ 4.29	$ 2.28
Cumulative effect of change in accounting principle		(0.09)	¾
Net income per share diluted	$ 5.44	$ 4.20	$ 2.28
Weighted average shares outstanding basic	29,616	31,097	30,569
Weighted average shares outstanding diluted	29,932	31,213	30,878

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

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THE HOUSTON EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME (LOSS)
(in thousands, except share data)

	Common Stock Shares	Common Stock $ Value	Additional Paid-In Capital	Unearned Compensation	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders Equity
Balance January 1, 2002	**30,463,230**	**$ 305**	**$ 336,977**	**$ (192)**	**$ 193,840**	**$ 34,951**	**$ 565,881**
Common shares issued stock options	490,788	5	9,663				9,668
Contributed capital KeySpan property acquisition			2,039				2,039
Amortization restricted stock				85			85
Tax benefit exercise of non-qualified stock options			4,775				4,775
Comprehensive income:							
Net income					70,494		70,494
Other comprehensive income:							
Derivative settlements reclassified to income, net of tax						(10,633)	(10,633)
Unrealized loss change in fair value of derivatives, net of tax						(49,520)	(49,520)
Total comprehensive income							10,341
Balance December 31, 2002	**30,954,018**	**$ 310**	**$ 353,454**	**$ (107)**	**264,334**	**(25,202)**	**$ 592,789**
Common shares issued stock options	461,563	5	10,218				10,223
Common shares issued restricted stock	22,000		812	(812)			
Common shares issued public offering	3,000,000	30	79,170				79,200
Common shares repurchased from	(3,000,000)	(30)	(79,170)				(79,200)

KeySpan							
Amortization restricted stock				111			111
Stock compensation expense stock options			903				903
Tax benefit exercise of non-qualified stock options			1,394				1,394
Comprehensive income:							
Net income					131,040		131,040
Other comprehensive income:							
Derivative settlements reclassified to income, net of tax						43,165	43,165
Unrealized loss change in fair value of derivatives, net of tax						(44,091)	(44,091)
Total comprehensive income							130,114
Balance December 31, 2003	**31,437,581**	**$ 315**	**$ 366,781**	**$ (808)**	**$ 395,374**	**$ (26,128)**	**$ 735,534**
Common shares issued stock options	873,626	9	25,586				25,595
Common shares issued restricted stock	49,000		2,855	(2,855)			
Common shares issued public offering	6,820,000	68	310,659				310,727
Common shares repurchase from KeySpan	(10,800,000)	(108)	(441,471)				(441,579)
Amortization restricted stock				1,126			1,126
Stock compensation expense stock options			3,670				3,670
Tax benefit exercise of non-qualified stock options			4,922				4,922
Comprehensive income (loss):							
Net income					162,824		162,824
Other comprehensive income (loss)							
Derivative settlements reclassified to income, net of tax						44,054	44,054
						(63,953)	(63,953)

Unrealized loss change in fair value of derivatives, net of tax														
Total comprehensive income														142,925
Balance December 31, 2004	**28,380,207**	**$**	**284**	**$**	**273,002**	**$**	**(2,537)**	**$**	**558,198**	**$**	**(46,027)**		**$**	**782,920**

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

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THE HOUSTON EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Years Ended December 31,		
	2004	**2003**	**2002**
Operating Activities:			
Net income	$ 162,824	$ 131,040	$ 70,494
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred income tax expense	50,500	58,274	35,085
Depreciation, depletion and amortization	265,148	197,530	171,610
Asset retirement accretion expense	4,902	3,668	
Stock compensation expense	4,796	1,014	85
Tax benefit non-qualified stock options	4,922	1,394	4,775
Unrealized loss due to ineffectiveness of derivative instruments	1,950	1,950	
Amortization of premiums paid on derivative contracts	5,287		
Debt extinguishment expense	211	1,626	
Cumulative effect of change in accounting principle		2,772	
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(8,387)	(4,863)	(45,337)
(Increase) decrease in inventories	95	361	(283)
(Increase) decrease in prepayments and other	(3,289)	(3,622)	763
(Increase) decrease in other assets	(6,218)	(8,449)	4,427
Increase (decrease) in deferred liabilities	7,276	2,329	741
Increase (decrease) in accounts payable and accrued expenses	34,988	5,808	1,509
Decrease in ARO liability for assets abandoned	(2,569)		
Net cash provided by operating activities	522,436	390,832	243,869
Investing Activities:			
Investment in property and equipment	(518,500)	(461,822)	(257,436)
Dispositions	13,283		5,311
Net cash used in investing activities	(505,217)	(461,822)	(252,125)
Financing Activities:			
Proceeds from long-term borrowings	420,000	414,000	79,000
Repayments of long-term borrowings	(367,000)	(364,000)	(71,000)
Debt issuance costs	(1,555)	(4,695)	
Proceeds from issuance of common stock from exercise of stock options	25,596	10,223	9,668
Proceeds from issuance of common stock	310,727	79,200	
Repurchase of common stock	(388,979)	(79,200)	
Net cash (used in) provided by financing activities	(1,211)	55,528	17,668
Decrease in cash and cash equivalents	16,008	(15,462)	9,412
Cash and cash equivalents, beginning of year	2,569	18,031	8,619

Cash and cash equivalents, end of year	$ 18,577	$ 2,569	$ 18,031
Supplemental Information:			
Non-cash transactions:			
Divesture and exchange of Appalachian Basin assets	$ 60,000		
Deferred tax benefit exchange of Appalachian Basin assets	7,400		
Cash paid (refunded) during period for:			
Interest	$ 16,385	$ 18,403	$ 14,906
Federal and state income taxes	$ 41,854	$ 14,800	$ (400)

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

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THE HOUSTON EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 Summary of Organization and Significant Accounting Policies

Our Business

We are an independent natural gas and oil producer concentrating on growing reserves and production through the exploration, development, exploitation and acquisition of natural gas and oil reserves in North America. Our core areas of operations are South Texas, offshore in the shallow waters of the Gulf of Mexico, the Arkoma Basin of Oklahoma and Arkansas and the Rocky Mountain region where, during 2003, we began operations with an initial focus in the Uinta Basin of northeastern Utah and during 2004, we expanded our focus to the DJ Basin in Eastern Colorado. In February 2004, we divested our South Louisiana assets and in June 2004, we divested our Appalachian Basin assets in connection with the KeySpan Exchange transaction described in Note 3 Stockholders Equity - *KeySpan Exchange and Offering.*

At December 31, 2004, our proved reserves were 793 billion cubic feet equivalent or Bcfe, with a standardized measure of future net cash flows, discounted at 10% per annum, including the effects of future income taxes of $1.4 billion. Our reserves are fully engineered on an annual basis by independent petroleum engineers. Approximately 94% of our proved reserves at December 31, 2004 were natural gas, approximately 63% of which were classified as proved developed. At December 31, 2004, we operated approximately 77% of our producing wells. Daily production averaged 339 million cubic feet of natural gas equivalent or MMcfe in 2004.

We were founded in December 1985 as a Delaware corporation and began exploring for natural gas and oil on behalf 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 and sold approximately 31% of our shares to the public. Through a series of three separate transactions, the first in February 2003 and the last in November 2004, KeySpan completely divested of its interest in the common stock of our company. As of December 31, 2004, KeySpan no longer owned any common stock of our company. See Note 3 Stockholders Equity and Note 6 Related Party Transactions for a description of these three transactions.

Principles of Consolidation

On June 2, 2004, all of the shares of our wholly-owned subsidiary, Seneca-Upshur Petroleum, Inc., were conveyed to KeySpan in connection with the KeySpan Exchange (as defined in Note 3 Stockholders Equity). Subsequent to the transaction, Seneca-Upshur is no longer a subsidiary of Houston Exploration but is a wholly-owned subsidiary of KeySpan, and as a result, our financial statements reflect the consolidated results of Seneca-Upshur through May 31, 2004. Seneca-Upshur was our only subsidiary, and prior to the KeySpan Exchange, our consolidated financial statements included our accounts and the accounts of Seneca-Upshur. All significant inter-company balances and transactions were eliminated.

Seneca-Upshur is in the exploration and production business in West Virginia with interests in Appalachian Basin assets. As of December 31, 2003, we had 50.5 Bcfe of estimated proved reserves in the Appalachian Basin. Because we account for our natural gas and oil assets under the full cost method of accounting, the disposition of our Appalachian Basin assets, which represented only a portion of our full cost pool, is not considered discontinued operations under the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) 144, Accounting for the Impairment and Disposal of Long-lived Assets.

Use of Estimates

The preparation of the consolidated financial statements in conformity with accounting principals generally accepted in the United States of America 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, our unevaluated properties and our full cost ceiling test limitation. In addition, estimates are used in computing taxes, preparing accruals of operating costs and production revenues, asset retirement obligations, fair value and effectiveness of derivative instruments and fair value of stock options and the related compensation expense. See Note 12 Supplemental Information on Natural Gas and Oil Exploration, Development and Production Activities

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited) for more information relating to estimates of proved reserves. Because there are numerous uncertainties inherent in the estimation process, actual results could differ materially from these estimates.

Business Segment Information

The Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) 131, Disclosures about Segments of an Enterprise and Related Information establishes standards for reporting information about operating segments. Operating segments are defined as components of an enterprise that engage in activities from which it may earn revenues and incur expenses. Separate financial information is available and this information is regularly evaluated by the chief decision maker for the purpose of allocating resources and assessing performance.

Segment reporting is not applicable for us as each of our operating areas has similar economic characteristics and each meets the criteria for aggregation as defined in SFAS 131. All of our operations involve the exploration, development and production of natural gas and oil and all of our operations are located in the United States. We have a single, company-wide management team that administers all properties as a whole rather than as discrete operating segments. We track only basic operational data by area. We do not maintain separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis. Throughout the year, we freely allocate capital resources on a project-by-project basis across our entire asset base to maximize profitability without regard to individual areas or segments.

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 marked-to-market at the end of each month at the lowest of (i) the price in effect at the time of production; (ii) the current market price; or (iii) the contract price, if a contract is in hand.

At December 31, 2004, we had production imbalances representing assets of $3.3 million and liabilities of $4.0 million. Our production imbalances represented a net asset of $1.8 million at December 31, 2003, of which we had a right to offset the liability with the asset for a majority of the balance. At December 31, 2004, the primary sources of our production imbalances related to Gulf of Mexico properties acquired in October 2004 from Orca Energy, L.P. and in October 2003 from Transworld Exploration and Production Inc. See Note 10 Acquisitions and Dispositions *Orca* and *Transworld*. Production imbalances are included in the line items other non-current assets and other non-current liabilities on the balance sheet.

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THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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. Fully diluted earnings per share assumes the conversion of all potentially dilutive securities and is calculated by dividing net income by the sum of the weighted average number of shares of common stock outstanding plus all potentially dilutive securities.

	Years Ended December 31,		
	2004	**2003**	**2002**
	(in thousands, except per share date)		
Numerator:			
Income before cumulative effect of change in accounting principle	$ 162,824	$ 133,812	$ 70,494
Cumulative effect of change in accounting principle		(2,772)	
Net income	$ 162,824	$ 131,040	$ 70,494
Denominator:			
Weighted average shares outstanding	29,616	31,097	30,569
Add dilutive securities: Stock options	316	116	309
Total weighted average shares outstanding and dilutive securities	29,932	31,213	30,878
Earnings per share basic:			
Income before cumulative effect of change in accounting principle	$ 5.50	$ 4.30	$ 2.31
Cumulative effect of change in accounting principle		(0.09)	
Net income per share basic	$ 5.50	$ 4.21	$ 2.31
Earnings per share diluted:			
Income before cumulative effect of change in accounting principle	$ 5.44	$ 4.29	$ 2.28
Cumulative effect of change in accounting principle		(0.09)	
Net income per share diluted	$ 5.44	$ 4.20	$ 2.28

For the years ended December 31, 2004, 2003 and 2002, the calculation of shares outstanding for diluted earnings per share does not include the effect of outstanding stock options to purchase 755,922, 1,865,313 and 1,880,029 shares respectively, because the exercise price of these shares was greater than the average market price for the year, which would have an antidulitive effect on earnings per share.

Comprehensive Income

Comprehensive income includes net income and certain items recorded directly to stockholders equity and classified as other comprehensive income. The table below summarizes comprehensive income and provides the components of the change in accumulated other comprehensive income for the twelve-month periods ended December 31, 2004, 2003 and 2002, respectively.

	For the Year Ended December 31,		
	2004	**2003**	**2002**
		(in thousands)	
Net income	$ 162,824	$ 131,040	$ 70,494
Other comprehensive income (loss)			
Derivative instruments settled and reclassified, net of tax	44,054	43,165	(10,633)
Change in unrealized loss fair value of open contracts, net of tax	(63,953)	(44,091)	(49,520)
Total other comprehensive (loss)	(19,899)	(926)	(60,153)
Comprehensive income	$ 142,925	$ 130,114	$ 10,341

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THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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. Our total unamortized cost base is the sum of our:

full cost pool (including assets associated with retirement obligations); plus,

estimates for future development costs (excluding asset retirement obligations; less,

unevaluated properties and their related costs; less,

estimates for salvage.

Costs associated with unevaluated properties are excluded from the amortization base until we have made a determination as to the existence of proved reserves. We review our unevaluated properties at the end of each quarter to determine whether the costs incurred should be reclassified to the full cost pool and thereby subject to amortization. Sales of natural gas and oil properties are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.

Under full cost accounting rules, total capitalized costs are limited to a ceiling equal to the present value of future net revenues, discounted at 10% per annum, plus the lower of cost or fair value of unproved properties less income tax effects (the ceiling limitation). We perform a quarterly ceiling test to 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 related 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 and adjusted for basis or location differential, held constant over the life of the reserves. We use derivative financial instruments that qualify for cash flow hedge accounting under SFAS 133 to hedge against the volatility of natural gas prices, and in accordance with SEC guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. In addition, subsequent to the adoption of SFAS 143, Accounting for Asset Retirement Obligations, the future cash outflows associated with settling asset retirement obligations are not included in the computation of the discounted present value of future net revenues for the purposes of the ceiling test calculation.

In calculating our ceiling test at December 31, 2004, 2003 and 2002, we estimated, using a wellhead price of $5.75 per Mcfe, $5.74 per Mcfe and $4.38 per Mcfe, 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 $399.3 million (after tax) for 2004, $440.7 million (after tax) for 2003 and by $279.4 million (after tax) for 2002. No writedown was required.

Unevaluated Properties. The costs associated with unevaluated properties and properties under development are not initially included in the amortization base and relate to unproved leasehold acreage, seismic data, wells and production facilities in progress and wells pending determination together with interest costs capitalized for these projects. Unevaluated leasehold costs are transferred to the amortization base with the costs of drilling the related well once determination has been made or upon expiration of a lease. Costs of seismic data are allocated to various unproved leaseholds and transferred to the amortization base with the associated leasehold costs on a specific project basis. Costs associated with wells in progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. Costs of dry holes are transferred to the amortization base immediately upon determination that the well is unsuccessful. All items included in our unevaluated property balance are assessed on a quarterly basis for possible impairment or reduction in value. Of the $122.7 million of unevaluated property costs at December 31, 2004 that have been excluded from the amortization base, $41.1 million were incurred during 2004, $48.2 million were incurred in 2003, $16.5 million were incurred in 2002 and $16.9 million were incurred prior to 2001. Of the $134.5 million of unevaluated property costs at December 31, 2003 that have been excluded

THE HOUSTON EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

from the amortization base, $78.9 million were incurred during 2003, $18.0 million were incurred in 2002, $21.4 million were incurred during 2001 and $16.2 were incurred prior to 2001. We estimate these costs will be evaluated within a four-year period.

Asset Retirement Obligations

On January 1, 2003, we adopted SFAS 143, Accounting for Asset Retirement Obligations, which addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. For us, asset retirement obligations (ARO) represent the systematic, monthly accretion and depreciation of future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities. SFAS 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 if a reasonable estimate of fair value can be made, and that the corresponding cost is capitalized as part of 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, an adjustment is made to the full cost pool, with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves. Under our previous accounting method, we included estimated future costs of abandonment and dismantlement in our full cost amortization base and amortized these costs as a component of our depletion expense. Subsequent to our adoption of SFAS 143, the ARO assets, which are carried on the balance sheet as part of the full cost pool, have been included in our amortization base for the purposes of calculating depreciation, depletion and amortization expense. For the purposes of calculating the ceiling test, the future cash outflows associated with settling the ARO liability have been excluded from the computation of the discounted present value of estimated future net revenues.

Pursuant to the January 1, 2003 adoption of SFAS 143 we:

- recognized a charge to income during the first quarter of 2003 of $2.8 million, net of tax, for the cumulative effect of the change in accounting principle;
- increased our total liabilities by $57.2 million to record the asset retirement obligations (ARO);
- increased our assets by $42.5 million to add the asset retirement costs to the carrying amount of our natural gas and oil properties; and
- reduced our accumulated depreciation, depletion and amortization by $10.4 million for the amount of expense previously recognized.

Adopting SFAS 143 had no impact on our reported cash flows. The following table describes changes in our asset retirement liability during each of the years ended December 31, 2004 and 2003. The ARO liability in the table below includes amounts classified as both current and long-term at December 31st.

	Years Ended December 31,	
	2004	**2003**
	(in thousands)	
ARO liability at January 1,	$ 92,357	$ 57,197
Accretion expense	4,902	3,668

Liabilities incurred from drilling	4,487	5,738
Liabilities incurred - assets acquired	19,638	29,243
Liabilities settled - assets sold	(12,714)	
Liabilities settled - assets abandoned	(4,915)	(160)
Changes in estimates	(12,009)	(3,329)
ARO liability at December 31,	$ 91,746	$ 92,357

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The following table describes the pro forma effect on net income and earnings per share for the year ended December 31, 2002, if SFAS 143 had been adopted on January 1, 2001.

	Years Ended December 31,		
	2004	**2003**	**2002**
	(in thousands, except per share amounts)		
Net income	$ 162,824	$ 131,040	$ 68,774
Earnings per share:			
Basic	$ 5.50	$ 4.21	$ 2.25
Diluted	5.44	4.20	2.23

Other Property and Equipment

Other property and equipment includes the costs of various gathering facilities that 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 computer equipment and other office equipment which are recorded at cost and depreciated using the straight-line method over estimated useful lives ranging between two to five years.

Cash and Cash Equivalents

We consider all highly liquid short-term investments with original maturities of three months or less to be cash and cash equivalents.

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 as of the balance sheet dates. 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

Under the full cost method of accounting, a portion of our general and administrative expenses that are directly identified with our acquisition, exploration and development activities are capitalized as part of our full cost pool. These capitalized costs include salaries, employee benefits, costs of consulting services and other specifically identifiable costs and do not include costs related to production operations, general corporate overhead or similar activities. We capitalized general and administrative costs directly related to our acquisition, exploration and development activities, during 2004, 2003 and 2002, of $14.8 million, $12.9 million and $13.2 million, respectively.

We receive reimbursement for administrative and overhead expenses incurred on behalf of other working interest owners on properties we operate. These reimbursements totaling $2.2 million, $1.6 million and $1.8 million for the years ended December 31, 2004, 2003 and 2002, respectively, were allocated as reductions to general and administrative expenses incurred. Generally, we do not receive any excess of reimbursements or fees over the costs incurred; however, if we did, we would credit the excess to the full cost pool to be recognized through lower cost amortization as production occurs.

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Capitalization of Interest

We capitalize interest related to our unevaluated natural gas and oil properties. For the years ended December 31, 2004, 2003 and 2002, we capitalized interest costs of $8.4 million, $7.3 million and $8.0 million, respectively.

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. See Note 2 Long-term Debt and Notes for fair value of our debt. Our derivative financial instruments are reported on the balance sheet at fair market value. See Note 7 Derivative Financial Instruments.

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. Based on the current demand for natural gas and oil, we do not expect that termination of sales to any of our current purchasers would have a material adverse effect on our ability to find replacement purchasers and to sell our production at favorable market prices.

Further, our derivative instruments also expose us to credit risk in the event of nonperformance by counterparties. Generally, these contracts are with major investment grade financial institutions and other substantive counterparties. We believe that our credit risk related to the natural gas futures and swap contracts is no greater than the risk associated with the primary contracts and that the elimination of price risk reduces volatility in our reported results of operations, financial position and cash flows from period to period and lowers our overall business risk; but, as a result of our hedging activities we may be exposed to greater credit risk in the future.

Derivative Instruments and Hedging Activities

Our hedging policy does not permit us to hold derivative instruments for trading purposes. In our hedging program, we utilize a variety of derivative instruments, including swaps, collars and options. We generally place contracts with major financial institutions and other credit-worthy counterparties. Although our hedging program protects a portion of our cash flows from downward price movements, certain hedging strategies, specifically the use of swaps and collars, may also limit our ability to realize the full benefit of future price increases. In addition, because our derivative instruments are typically indexed to New York Mercantile Exchange (NYMEX) prices as opposed to the index price where the gas is actually sold, our hedging strategy may not protect our cash flows if the price differential increases between the NYMEX price and index price for the point of sale.

Our derivative instruments are designated cash flow hedges and qualify for hedge accounting under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, as amended, and, accordingly, we carry the fair market value of our derivative instruments on the balance sheet as either an asset or liability and defer unrealized 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 the income statement. For each the years ended December 31, 2004 and 2003, our net income includes an unrealized loss of $1.9 million ($1.3 million net of tax), which represents the ineffective portion of our derivative instruments that was not eligible for deferral. The ineffectiveness was a result of changes at the end of the current period in the price differentials between the index price of the derivative contract, which uses a NYMEX index, and index price for the point of sale for the cash flow that is being hedged, the majority of which is the Houston Ship Channel index.

Based on market prices at December 31, 2004, we recorded an unrealized loss in accumulated other comprehensive income of $46.0 million, net of tax, representing the fair value of our open contracts. Any loss will be realized in future earnings at the time of the related sales of natural gas production applicable to specific hedges. If prices in effect at December 31, 2004 were to remain unchanged, over the next 12-month period, we would expect to reclassify from accumulated other comprehensive income to earnings a loss of $41.7 million, net of tax, relating to our open derivative contracts. However,

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these amounts could vary materially as a result of changes in market conditions. See Note 7 Derivative Instruments, for a detailed listing of our derivative contracts and the fair market value of those contracts as of December 31, 2004 and 2003.

Accounting for Stock Options

On January 1, 2003, we adopted the fair value expense recognition provisions of SFAS 123, Accounting for Stock Based Compensation, as amended by SFAS 148, Accounting for Stock Based Compensation Transition and Disclosure using the prospective method as defined by the SFAS 148. As a result, we now record as compensation expense the fair value of all stock options issued subsequent to January 1, 2003. No expense for stock options has been recorded for grants made in years prior to January 1, 2003. Prior to 2003, we accounted for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board (APB) Opinion 25, Accounting for Stock Issued to Employees, and related interpretations. Accordingly, compensation cost for stock options was 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 was equal to the fair market value at the time of grant, no compensation expense was incurred. If we had accounted for all stock options using the fair value method as recommended in SFAS 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, 2004, 2003 and 2002.

	Years Ended December 31,		
	2004	**2003**	**2002**
	(in thousands, except per share data)		
Net income as reported	$ 162,824	$ 131,040	$ 70,494
Add: Stock-based compensation expense included in net income, net of tax	2,581	551	55
Less: Stock-based compensation expense determined using fair value method, net of tax	4,694	4,427	3,631
Net income pro forma	$ 160,711	$ 127,164	$ 66,918
Net income per share basic as reported	$ 5.50	$ 4.21	$ 2.31
Net income per share diluted as reported	5.44	4.20	2.28
Net income per share basic pro forma	$ 5.43	$ 4.09	$ 2.19
Net income per share diluted pro forma	5.37	4.07	2.17

The effects of applying SFAS 123 in this pro forma disclosure may not be representative of future amounts. See Note 4 Employee Benefit and Stock and Options Plans, for a summary of stock compensation expenses incurred during the years ended December 31, 2004, 2003 and 2002. The weighted average fair value of options at their grant date during 2004, 2003 and 2002 were 17.12. $13.82 and $14.08, 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 2004, 2003 and 2002:

Years Ended December 31,

	2004	2003	2002
Risk-free interest rate.	3.88%	4.02%	4.59%
Expected years until exercise	5	5	5
Expected stock volatility	40%	43%	46%
Expected dividends			

New Accounting Pronouncements

On September 28, 2004, the SEC released Staff Accounting Bulletin (SAB) 106 regarding the application of SFAS 143, Accounting for Asset Retirement Obligations (AROs), by oil and gas producing companies following the full cost accounting method. Pursuant to SAB 106, oil and gas producing companies that have adopted SFAS 143 should exclude the future cash outflows associated with settling AROs (ARO liabilities) from the computation of the present value of estimated future net revenues for the purposes of the full cost ceiling calculation. In addition, estimated dismantlement and abandonment costs, net of estimated salvage values, that have been capitalized (ARO assets) should be included in the amortization base for computing depreciation, depletion and amortization expense. Disclosures are required to include discussion of how a company s ceiling test and depreciation, depletion and amortization calculations are impacted by the adoption of SFAS 143. SAB 106 is effective prospectively as of the beginning of the first fiscal quarter beginning after

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October 4, 2004. Since our adoption of SFAS 143 on January 1, 2003, we have calculated the ceiling test and our depreciation, depletion and amortization expense in accordance with the interpretations set forth in SAB 106; therefore, the adoption of SAB 106 had no effect on our financial statements.

On December 16, 2004, the FASB revised Statement 123 (revised 2004), Share-Based Payment that will require compensation costs related to share-based payment transactions (e.g., issuance of stock options and restricted stock) to be recognized in the financial statements. With limited exceptions, the amount of compensation cost will be measured based on the grant-date fair value of the equity or liability instruments issued. In addition, liability awards will be measured each reporting period. Compensation cost will be recognized over the period that an employee provides service in exchange for the award. Statement 123(R) replaces SFAS 123, Accounting for Stock-Based Compensation, and supersedes Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees. For us, SFAS 123(R) is effective for the first quarterly reporting period after June 15, 2005. Entities that use the fair-value-based method for either recognition or disclosure under SFAS 123 are required to apply SFAS 123(R) using a modified version of prospective application. Under this method, an entity records compensation expense for all awards it grants after the date of adoption. In addition, the entity is required to record compensation expense for the unvested portion of previously granted awards that remain outstanding at the date of adoption. In addition, entities may elect to adopt SFAS 123(R) using a modified retrospective method where by previously issued financial statements are restated based on the expense previously calculated and reported in their pro forma footnote disclosures.

On January 1, 2003, we adopted the fair value expense recognition provisions of SFAS 123 as amended by SFAS 148, Accounting for Stock-Based Compensation Transition and Disclosure using the prospective method as defined by the SFAS 148. As a result, we have recognized compensation expense for all stock options granted subsequent to January 1, 2003 with no expense recognized for grants made prior to 2003. Adoption of SFAS 123(R) will require us to recognize compensation expense over the remaining service period for the unvested portion of all options granted during 2000, 2001 and 2002. All options granted prior to 2000 are fully vested. We expect to adopt SFAS 123(R) on January 1, 2005 using the modified version of the prospective application and are currently evaluating the effect of adopting SFAS 123(R).

On December 16, 2004, the FASB issued Statement 153, Exchanges of Nonmonetary Assets , an amendment of APB Opinion No. 29, to clarify the accounting for nonmonetrary exchanges of similar productive assets. SFAS 153 eliminates the exception from the fair value measurement for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. The Statement will be applied prospectively and is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. We do not have any nonmonetary transactions for any period presented that this Statement would apply. We do not expect the adoption of SFAS 153 to have a material impact on our financials statements.

NOTE 2 Long-Term Debt and Notes

	Years Ended December 31,	
	2004	**2003**
	(in thousands)	
Senior Debt:		

Revolving bank credit facility, due April 1, 2008	$ 180,000	$ 127,000
Subordinated Debt:		
7% senior subordinated notes, due June 15, 2013	175,000	175,000
Total long-term debt and notes	$ 355,000	$ 302,000

The carrying amount of borrowings outstanding under the revolving bank credit facility approximates fair value as the interest rates are tied to current market rates. At December 31, 2004, the quoted market value of our $175 million of 7% senior subordinated notes was 101% of the $175 million carrying value or $177 million. At December 31, 2003, the quoted market value of our $175 million of 7% senior subordinated notes was 103% of the $175 million carrying value or $180.3 million. At December 31, 2004, principle payments due over the next five-year period and thereafter are as follows.

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	2005	2006	2007	2008	2009	After 2010
			(in thousands)			
Revolving bank credit facility	$	$	$	$ 180,000	$	$
7% senior Subordinated Notes						175,000
Total maturities	$	$	$	$ 180,000	$	$ 175,000

Revolving Bank Credit Facility

We maintain a revolving bank credit facility with a syndicate of lenders led by Wachovia Bank, National Association, as issuing bank and administrative agent, The Bank of Nova Scotia and Fleet National Bank as co-syndication agents and BNP Paribas and Comerica Bank as co-documentation agents. The credit facility was amended and restated on April 1, 2004, primarily to increase the size of the facility, and was amended again on June 2, 2004, in conjunction with the KeySpan Exchange (as defined in Note 3). As amended, the facility provides us with a commitment of $400 million, which may be increased at our request and with prior approval from Wachovia to a maximum of $450 million. Amounts available for borrowing under the credit facility are limited to a borrowing base. On April 1, 2004, our borrowing base was increased from $300 million to $375 million, and on June 2, 2004, was reduced to $340 million as a result of the disposition of our Appalachian Basin assets in the KeySpan Exchange. Pursuant to the reduction in our borrowing base, we incurred $0.2 million debt extinguishment expenses during the second quarter of 2004 relating to the write-off of a portion of our debt issuance costs. The $0.2 million is included in the line item Other (income) expense on our Statement of Operations. Effective October 15, 2004, our borrowing base was increased to $400 million, which is expected to remain in effect until the next scheduled redetermination on April 1, 2005. Up to $40 million of the borrowing base is available for the issuance of letters of credit. Outstanding borrowings are unsecured and rank senior in right of payment to our $175 million 7% subordinated notes. The amended facility matures on April 1, 2008. At December 31, 2004, we had $180 million in outstanding borrowings under the credit facility and $0.4 million in outstanding letter of credit obligations.

Interest rates, margins and terms of payment remained unchanged from prior periods pursuant to the April 1, 2004, amendment. Interest is payable on borrowings under our revolving bank credit facility, as follows:

- on base rate loans, at a fluctuating rate, or base rate, equal to the sum of (a) the greater of the Federal funds rate plus 0.5% or Wachovia s prime rate plus (b) a variable margin between 0.00% and 0.50%, depending on the amount of borrowings outstanding under the credit facility, or

- on fixed rate loans, a fixed rate equal to the sum of (a) a quoted LIBOR rate divided by one minus the average maximum rate during the interest period set for certain reserves of member banks of the Federal Reserve System in Dallas, Texas, plus (b) a variable margin between 1.25% and 2.00%, depending on the amount of borrowings outstanding under the credit facility.

Interest is payable on base-rate loans on the last day of each calendar quarter. Interest on fixed-rate loans is generally payable at maturity or at least every 90 days if the term of the loan exceeds three months. In addition to interest, we must pay a quarterly commitment fee of between 0.30% and 0.50% per annum on the unused portion of the borrowing base.

Our revolving bank credit facility contains customary negative covenants that place restrictions and limits on, among other things, the incurrence of debt, guarantees, liens, leases and certain investments. The credit facility also restricts and limits our ability to pay cash dividends, to purchase or redeem our stock and to sell or encumber our assets. Financial covenants require us to, among other things:

- maintain a ratio of earnings before interest, taxes, depreciation, depletion and amortization (EBITDA) to cash interest payments of at least 3.00 to 1.00;
- maintain a ratio of total debt to EBITDA of not more than 3.50 to 1.00; and
- not hedge more than 85% of our production during any calendar year.

At December 31, 2004, and December 31, 2003, we were in compliance with all covenants.

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Senior Subordinated Notes

On June 10, 2003, we issued $175 million of 7% senior subordinated notes due June 15, 2013. The notes bear interest at a rate of 7% per annum with interest payable semi-annually on June 15 and December 15, beginning December 15, 2003. We may redeem the notes at our option, in whole or in part, at any time on or after June 15, 2008, at a price equal to 100% of the principal amount plus accrued and unpaid interest, if any, plus a specified premium that decreases yearly from 3.5% in 2008 to 0% in 2011 and thereafter. In addition, at any time prior to June 15, 2006, we may redeem up to a maximum of 35% of the aggregate principal amount with the net proceeds of one or more equity offerings at a price equal to 107% of the principal amount, plus accrued and unpaid interest and liquidated damages, if any. The notes are general unsecured obligations and rank subordinate in right of payment to all existing and future senior debt, including the revolving bank credit facility, and will rank senior or equal in right of payment to all existing and future subordinated indebtedness.

The indenture governing the notes contains covenants that, among other things, restrict or limit:

- incurrence of additional indebtedness and issuance of preferred stock;
- repayment of certain other indebtedness;
- payment of dividends or certain other distributions;
- investments and repurchases of equity;
- use of the proceeds of assets sales;
- transactions with affiliates;
- creation, incurrence or assumption of liens;
- merger or consolidation and sales or other dispositions of all or substantially all of our assets;
- entering into agreements that restrict the ability of our subsidiary to make certain distributions or payments; or
- guarantees by our subsidiary of certain indebtedness.

In addition, 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 and liquidated damages, 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 the period constituted our board of directors, including any new directors who were approved by a majority vote of directors then in office who were either directors at the beginning of the two-year period or who were previously so approved, cease for any reason to constitute a majority of the members then in office.

NOTE 3 Stockholders Equity

KeySpan Secondary Offering

On November 24, 2004, KeySpan completed a secondary public offering of its remaining 6,580,392 shares of our common stock at $56.25 per share. All shares were offered by KeySpan under our shelf registration statement filed with the Securities and Exchange Commission on March 16, 2004. We did not receive any proceeds from the sale of these shares in the offering. Subsequent to the offering, KeySpan no longer held any common stock of our company.

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KeySpan Exchange and Offering

On June 2, 2004, we completed an asset exchange transaction with KeySpan pursuant to which we redeemed and cancelled 10,800,000 shares of our common stock owned by KeySpan in exchange for all the stock of Seneca-Upshur Petroleum, Inc., our wholly-owned subsidiary, to which we contributed all of our Appalachian Basin assets valued at $60 million and $389 million in cash, for a total exchange value of $449 million. This transaction is referred to as the KeySpan Exchange. The KeySpan Exchange is intended to qualify as a tax-free exchange under Section 355(a) of the Internal Revenue Code.

To fund the cash portion of the exchange, on June 2, 2004, we sold 6,200,000 shares of our common stock in a registered public offering at $48.00 per share, (the Offering), and contributed to Seneca-Upshur substantially all of the net proceeds from the Offering (approximately $282 million), together with an additional $107 million of proceeds from bank borrowings. We then conveyed to KeySpan all of the shares of Seneca-Upshur in exchange for 10,800,000 shares of our common stock owned by KeySpan.

On June 23, 2004, the underwriters of our Offering exercised a portion of their over-allotment option and we sold an additional 620,000 shares of common stock at $48.00 per share for net proceeds of $28.6 million. The proceeds from the over-allotment were used to reduce bank borrowings.

Our redemption and cancellation of the 10,800,000 shares received from KeySpan and our issuance of 6,820,000 new shares resulted in a net 3,980,000 decrease in the outstanding shares of our common stock, and thereby reduced KeySpan s ownership from approximately 54% to 24%. As a result of the KeySpan Exchange and Offering, our bank borrowings increased by a net $79 million and we incurred approximately $5.1 million in compensation and other expenses related to special bonuses awarded to executives and key employees who assisted in structuring and consummating the transactions. As a result of the reduction in ownership, KeySpan agreed to reduce its representation on our Board of Directors from five to two directors. Our Chief Executive Officer, William G. Hargett, was elected Chairman of the Board replacing Robert B. Catell, Chairman and Chief Executive Officer of KeySpan, who remains on the Board.

Stockholder Rights Plan

On August 12, 2004, we adopted a stockholder rights plan designed to assure that our stockholders receive fair and equal treatment in the event of an unsolicited attempt to takeover our company and to protect against abusive or coercive takeover tactics that are not in the best interest of our company or its stockholders. To implement the rights plan, the Board of Directors declared a dividend of one preferred share purchase right for each outstanding share of our common stock to stockholders of record as of the close of business on August 23, 2004, and directed the issuance of one preferred share purchase right with respect to each share of our common stock that shall become outstanding thereafter until the rights become exercisable or they expire as described below. Each right initially represents a contingent right to purchase, under certain circumstances, one one-thousandth of a share of our Series A Junior Participating Preferred Stock, par value $.01 per share, at an initial exercise price of $275.00 per one one-thousandth of a share, subject to adjustment under certain circumstances. The rights will become exercisable and trade independently from our common stock upon the public announcement of the acquisition by a person or group of 10% or more of our common stock, or ten days after commencement of a tender or exchange offer that would result in the acquisition of 10% or more of our common stock.

Each share purchased upon exercise of the rights will be entitled to a minimum quarterly preferential dividend payment of the greater of (i) $10.00 per share and (ii) an amount equal to 1,000 times the dividend declared per share of common stock. Each share will be entitled to 1,000 votes, voting together with the common stock. In the event of our liquidation, each share of the Series A Junior Participating Preferred Stock will be entitled to a minimum preferential payment of the greater of (a) $10.00 per share (plus any accrued but unpaid dividends) and (b) an amount equal to 1,000 times the payment made per share of common stock.

If we are acquired in a merger or other business combination transaction after a person or group has acquired 10% or more of our common stock, each right will entitle its holder to purchase, at the rights exercise price, that number of the acquiring company s shares of common stock having a market value of twice the right s exercise price. In addition, if a person or group acquires 10% or more of our common stock, each right will entitle its holder (other than the acquiring person or group) to purchase, at the right s exercise price, a number of fractional shares of the Series A Junior Participating Preferred Stock or shares of our common stock having a market value of twice the right s exercise price.

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The rights expire on August 12, 2014, unless redeemed earlier by our Board of Directors. The Board of Directors can redeem the rights at a price of $.01 per right at any time before the rights become exercisable, and thereafter only in limited circumstances.

Issuance of 3,000,000 Shares to the Public and Concurrent Repurchase of 3,000,000 Shares from KeySpan

In connection with our initial public offering in September 1996, we entered into a registration rights agreement with KeySpan pursuant to which we were obligated, at KeySpan s election, to facilitate KeySpan s sale of its shares of our stock by registering the shares under the Securities Act of 1933 and assisting in KeySpan s selling efforts. During February of 2003, KeySpan notified us of its desire to sell 3,000,000 shares of their Houston Exploration stock. To accomplish the transaction, we sold 3,000,000 newly issued shares of our stock in a public offering under our shelf registration statement for net proceeds of $26.40 per share, or an aggregate $79.2 million, and simultaneously bought a like number of KeySpan s shares of our stock for the same price per share. We cancelled the 3,000,000 shares acquired from KeySpan immediately following the repurchase. KeySpan reimbursed us for all costs and expenses, and the transaction had no impact on our capitalization. The transaction was evidenced in a stock purchase agreement, dated February 26, 2003. As a result of the transactions, KeySpan s interest in our outstanding shares decreased from 66% to 55%.

NOTE 4 Employee Benefit and Stock and Option Plans

401(k) Plan

We maintain a tax-qualified defined contribution plan under Section 401(k) of the Internal Revenue Code for our employees. All employees are eligible to participate in the plan upon reaching 21 years of age and completing one month of service. Participants may elect to have us contribute on their behalf up to 12.5% of their total compensation (subject to limitations imposed under the current Internal Revenue Code) 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 Code. The amounts contributed under the 401(k) plan are held in a trust and invested at the direction of each participant among various investment funds. An employee s salary deferral contributions to the 401(k) plan are 100% vested. Our matching contributions vest at the rate of 20% per year of service. Participants are entitled to distribution of their vested account balances upon termination of employment. We made contributions to the 401(k) plan of $1.2 million, $1.3 million and $1.2 million, respectively, for the years ended December 31, 2004, 2003 and 2002.

Deferred Compensation Plan

We maintain a deferred compensation plan for the benefit of our employees. The plan is a non-qualified plan and is intended to supplement our 401(k) plan by allowing highly compensated employees to save on a tax deferred basis a portion of their eligible compensation subject to limitations imposed by the plan. Under the terms of the plan, employees who have made the maximum allowable contribution to their 401(k) accounts for any year ($13,000, $12,000 and $11,000 per year, respectively, for 2004, 2003 and 2002, with an additional one-time contribution of $3,000 in 2004, $2,000 in 2003 and $1,000 in 2002 for employees 50 years of age or older) may elect to defer an additional portion of their compensation into the deferred compensation plan. We match 100% of each employee s deferral up to an aggregate contribution of 12.5% under both the 401(k) plan and the deferred compensation plan. During 2004, 2003 and 2002, we made matching contributions totaling $0.7 million, $0.7 million and $0.5 million, respectively, to the deferred compensation plan. Employer contributions vest 20% per year and become fully vested after a five-year period. Notional accounts are maintained for each eligible employee to record salary deferrals, matching contributions and earnings and losses. We make contributions to a grantor trust to fund plan benefits, but the assets of the trust are subject to the claims of our general creditors. Assets of the grantor trust are invested, at the direction of the employee, in various investment funds. Income on trust assets is treated as our income. Participants are entitled to a benefit attributable to their deferrals and the vested portion of our matching contributions at predetermined future dates or upon termination of their employment. At December 31, 2004 and 2003, the fair market value of the assets held in the trust of $6.7 million and $3.4 million, respectively, are carried on our balance sheet as a non-current asset together with a corresponding non-current liability for the same amount and are located in the line items Other Non-Current Assets and Other Deferred Liabilities.

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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 became 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 $105,000 during each of the years ended December 31, 2004, 2003 and 2002 related to this retirement plan. Annual expense incurred is greater than annual distribution due to the actuarial estimate of the future liability.

Employee Annual Incentive Compensation Plan

We maintain an Annual Incentive Compensation Plan that provides an annual incentive bonus to all full-time employees if certain performance goals are met during the year. The plan is administered by our Chief Executive Officer on behalf of our Board of Directors and the Compensation Committee. Annual objectives and incentive opportunity levels are established and approved by the Compensation Committee. Incentive awards are earned based on our actual performance in relation to pre-established objectives and on an assessment of individual contribution during the year. We incurred incentive compensation costs of approximately $6.2 million, $4.8 million and $3.7 million in 2004, 2003 and 2002.

Deferred Compensation Plan for Non-Employee Directors

We maintain a deferred compensation plan for non-employee, non-affiliated directors, which was adopted by our Board of Directors in October 1997 and under which participants 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. The term phantom stock rights refers to units of value that track the performance of our company s common stock. These units are not convertible to stock and do not possess any voting rights. Phantom stock rights are exchanged for a cash distribution upon retirement.

Stock and Option Plans

We have four stock options plans, together our (Stock Plans): (i) 1996 Stock Option Plan which was adopted at the completion of our initial public offering in September 1996, amended and approved by the stockholders in 1997; (ii) 1999 Non-Qualified Stock Option Plan adopted by our Board of Directors in October 1999; (iii) 2002 Long-Term Incentive Plan adopted in January 2002, approved by the stockholders in May 2002 and amended by our Board in October 2003; and (iv) 2004 Long -Term Incentive Compensation Plan, approved by the stockholders in June 2004. All our employees, directors, consultants and advisors are eligible to participate in our Stock Plans, with the exception of executive officers that are not eligible to participate in the 1999 Plan. Options granted under our Stock Plans 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 directors whose options vest immediately upon grant. All grants are made at the closing price of our common stock as reported on the NYSE on the date of grant. The 1996, 2002 and 2004 Plans allow for the grant of both incentive stock options and non-qualified stock options.

Common stock issued through the exercise of non-qualified options will result in a tax deduction for us which is equal to the taxable gain recognized by the optionee. Generally, we will not receive an income tax deduction for incentive based options. For financial reporting purposes, the tax effect of this deduction is accounted for as a credit to additional paid-in-capital rather than as a reduction of income tax expense. The exercise of stock options during 2004, 2003 and 2002 resulted in a current tax benefit to us of approximately $4.9 million, $1.4 million and $4.8 million, respectively.

In addition to stock options, the 2002 Plan and 2004 Plan allow for the grant of restricted stock. Restricted stock carries voting and dividend rights; however, the sale or transfer of the shares is restricted. During 2004 and 2003, restricted stock was granted and issued to certain executive officers, non-employee directors and affiliated directors as a component of each recipient s annual compensation. Generally, restricted shares vest and become freely transferable at the end of five years from the date of grant. Accelerated vesting will occur upon the occurrence of certain events, including retirement from the company or Board of Directors or upon a change of control (as defined by the Plan).

On January 1, 2003, we adopted the fair value expense recognition provisions of SFAS 123, as amended by SFAS 148, Accounting for Stock Based Compensation Transition and Disclosure using the Prospective Method as defined by the SFAS 148. As a result, we now record as compensation expense the fair value of all stock options issued subsequent to January 1, 2003. No expense for stock options was incurred prior to January 1, 2003.

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The table below provides a detail of stock compensation expenses incurred during the years ended December 31, 2004 and 2003. For 2004, we incurred additional expense of $1.6 million related to the accelerated vesting of stock options and $0.8 million for the accelerated vesting of restricted stock for retiring executive officers and members of our Board of Directors.

	Years Ended December 31,		
	2004	2003	2002
	(in thousands)		
Options	$ 3,670	$ 903	$
Restricted stock[(1)]	1,126	111	85
Amounts capitalized	(800)	(166)	
Stock compensation expense, net of amounts capitalized	$ 3,996	$ 848	$ 85

(1) Includes $21,000, $85,000 and $85,000, respectively, during 2004, 2003 and 2002 for the amortization of 10,000 shares of restricted stock granted to our Chief Executive Officer upon his employment with our company in April 2001. These shares fully vested in April 2004 and were not made pursuant to one of our Plan.

The table below summarizes all of our Stock Plans as of December 31, 2004. Pursuant to shareholder approval of the 2004 Plan received at our annual meeting in June 2004, all remaining options available for grant under the 2002, 1999 and 1996 Plans were cancelled and 1,500,000 shares were made available for grant under the 2004 Plan.

	2004 Plan	**2002 Plan**	**1999 Plan**	**1996 Plan**	**Total Plans**
Options and restricted stock authorized	1,500,000	1,500,000	800,000	3,033,912	6,833,912
Options granted:					
Incentive stock options		47,686		1,032,302	1,079,988
Non-qualified stock options	301,450	1,193,989	806,606	2,009,910	4,311,955
Forfeitures	(3,425)	(39,110)	(39,443)	(11,877)	(93,855)
Cancellations		(275,435)	(32,837)	(3,577)	(311,849)
Total options	298,025	1,478,000	800,000	3,033,912	5,609,937
Restricted stock granted [(1)]	49,000	22,000			71,000
Options and restricted stock available for grant	1,152,975				1,152,975
Total exercised and issued		269,320	421,734	2,649,436	3,340,490

(1) Average grant price for restricted shares issued was $58.28 and $35.08, respectively, during years ended December 31, 2004 and 2003.

The table below summarizes the activity for stock options during the respective years for all of our stock plans.

	Years Ended December 31,					
	2004		2003		2002	
	Shares	**Price** [(1)]	**Shares**	**Price** [(1)]	**Shares**	**Price** [(1)]
Options outstanding January 1	2,535,159	$ 30.23	2,421,166	$ 27.50	2,164,448	$ 24.81
Granted	342,950	55.98	606,725	34.86	753,559	30.14
Exercised	(873,626)	29.30	(461,563)	22.15	(490,788)	19.70
Forfeited	(46,885)	34.49	(31,169)	27.73	(6,053)	27.77
Options outstanding December 31	1,957,598	$ 35.05	2,535,159	$ 30.23	2,421,166	$ 27.50
Options exercisable December 31	555,546	$ 29.80	838,568	$ 28.28	848,103	$ 25.12
Options available for grant December 31	1,152,975		309,889		906,945	

(1) Weighted average price. For all grants, the 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 the number vested and exercisable as of December 31, 2004.

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Range of Exercise Prices	Options Outstanding Shares Underlying Options	Year Granted	Remaining Contractual Life	Weighted Average Exercise Price	Options Exercisable/Vested Shares Underlying Options	Options Exercisable/Vested Weighted Average Exercise Price	Unvested Shares Underlying Options
$15.50 - $17.25	15,000	1996	2 years	$ 15.60	15,000	$ 15.60	
$13.13 - $25.00	17,900	1997	3 years	20.74	17,900	20.74	
$15.75 - $23.38	6,920	1998	4 years	18.86	6,920	18.86	
$16.94 - $21.00	41,000	1999	5 years	19.33	41,000	19.33	
$18.00 - $26.19	46,700	2000	6 years	23.49	33,800	24.07	12,900
$22.50 - $37.38	494,808	2001	7 years	29.41	218,361	29.85	276,447
$27.49 - $33.75	483,540	2002	8 years	30.15	109,560	30.05	373,980
$26.18 - $37.42	512,705	2003	9 years	34.87	94,005	35.36	418,700
$36.56 - $60.45	339,025	2004	10 years	55.98	19,000	56.89	320,025
	1,957,598			$ 35.05	555,546	$ 29.80	1,402,052

NOTE 5 Income Taxes

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

	Years Ended December 31, 2004	2003	2002
	(in thousands)		
Current	$ 46,092	$ 13,913	$ 4,007
Deferred	50,500	58,274	35,085
Total	$ 96,592	$ 72,187	$ 39,092

For 2002, the current provision includes $0.8 million in Section 29 tax credits (see Note 6 Related Party Transactions *Section 29 Tax Credits*). At December 31, 2004 and 2003, we had no net operating loss carryforwards remaining for federal income tax purposes. At of December 31, 2002, we had net operating loss carryforwards of approximately $47.5 million. Net operating loss carryforwards 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, 2004	2003	2002

		(in thousands)	
Income before income taxes	$ 259,416	$ 205,999	$ 109,586
Statutory rate	35%	35%	35%
Income tax expense computed at statutory rate	90,796	72,100	38,355
Reconciling items:			
State income taxes and other, net of federal tax benefit	4,358		
Section 29 tax credits and other tax credits [1]		58	(804)
Permanent differences	45	29	
Non-deductible compensation expense	1,393		1,541
Tax provision	$ 96,592	$ 72,187	$ 39,092

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(1) For 2003, excess deductions taken in 2002.

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Deferred Income Taxes

Deferred income taxes primarily represent the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of our deferred taxes are detailed in the table below.

For 2004, the change in the balance of our deferred tax liability was comprised of deferred tax expense of $50.5 million, a tax benefit of $11.1 million due to the change in the fair value of our open derivative contracts that has been deferred in accumulated other comprehensive income and a reduction of $7.4 million to our deferred tax liabilities related to oil and gas property and equipment associated with the Appalachian Basin assets divested as part of the KeySpan Exchange in June 2004.

For 2003, the change in the balance of our deferred tax liability was comprised of deferred tax expense of $59.7 million, a tax benefit of $1.5 million pursuant to the cumulative effect of the change in accounting principle for the adoption of SFAS 143 and a tax benefit of $1.2 million due to the change in the fair value of our open derivative contracts that has been deferred in accumulated other comprehensive income.

	Years Ended December 31,	
	2004	**2003**
	(in thousands)	
Deferred tax assets:		
Derivative instruments	$ 25,222	$ 14,752
Ineffectiveness derivative instruments	1,381	682
Alternative minimum tax credit carryforwards		7,187
Deferred compensation	4,327	1,203
Total deferred tax assets	30,930	23,824
Deferred tax liabilities:		
Oil and gas property and equipment	294,898	255,605
Total deferred tax liability	$ 263,968	$ 231,781

NOTE 6 Related Party Transactions

Transactions With KeySpan

KeySpan Exchange

To facilitate the KeySpan Exchange (see Note 3 *KeySpan Exchange and Offering*), we entered into a Distribution Agreement with KeySpan that defines each company s rights and obligations with respect to the exchange transaction. The Distribution Agreement contains, among other provisions, customary representations and warranties concerning our Appalachian Basin properties, including title, regulatory compliance and environmental matters, along with limited indemnification obligations. Pursuant to the Distribution Agreement, the two companies also entered into a Tax Matters Agreement, which generally provides that each party would be responsible for its own tax consequences if the KeySpan Exchange fails to qualify as a tax-free transaction. In addition, we entered into a Transition Services Agreement pursuant to which we will provide KeySpan with transitional services with respect to the Appalachian Basin assets for a fee of $27,000 per month until March 31, 2005.

Issuance of 3,000,000 Shares to the Public and Concurrent Repurchase of 3,000,000 Shares from KeySpan. See Note 3 Stockholders Equity.

Sale of Section 29 Tax Credits

In June 2003, we repurchased, for $2.6 million, certain interests in producing wells that were sold in January 1997, to a subsidiary of KeySpan under an agreement designed to monetize tax credits available 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. The wells subject to the agreement are located in West Virginia, Oklahoma and East Texas and produce from formations

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that qualify for Section 29 tax credits. Pursuant to the agreement, KeySpan acquired an economic interest in wells that 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.

During the term of the agreement, we managed and administered the daily operations of the properties in exchange for an annual management fee of $100,000. The agreement expired December 31, 2002, and as a result, we were required to repurchase the interests in the producing wells from KeySpan. Subsequent to the repurchase, ownership of the tax credits reverted back to us. The income statement effect, representing benefits received from Section 29 tax credits, was a benefit of $0.8 million both during 2002 and 2001, with no benefit during 2003.

Acquisition of KeySpan Joint Venture Assets

In October 2002, we purchased from KeySpan a portion of the assets developed under the joint exploration agreement with KeySpan Exploration & Production, LLC, a subsidiary of KeySpan (see discussion of KeySpan Joint Venture below). The acquisition consisted of interests averaging between 11.25% and 45% in 17 wells covering eight of the twelve blocks that were developed under the joint exploration agreement from 1999 through 2002. KeySpan retained a 45% interest in four blocks: South Timbalier 314 and 317 and Mustang Island 725 and 726, as these blocks were in various stages of development at the time of the acquisition. KeySpan committed to continued participation in the ongoing development of these blocks, which included the completion of the platform and production facilities at South Timbalier 314/317, together with possible further developmental drilling. Both Houston Exploration and KeySpan farmed out their interest in Mustang Island 725/726 during 2003. At September 1, 2002, the effective date of the purchase, the estimated proved reserves associated with the interests acquired were 13.5 Bcfe. The $26.5 million purchase price was paid in cash and financed with borrowings under our revolving credit facility. Subsequent purchase price adjustments reduced our acquisition price by $1.2 million. The purchase price was adjusted for various closing items in the normal course of business, including revenues received by and expenditures made by the seller related to the properties acquired for the period between the effective date of the transaction (September 1, 2002) and the closing date (October 11, 2002). Our acquisition of the properties was accounted for as a transaction between entities under common control. As a result, the excess book value of the properties acquired of $3.1 million ($2.0 million net of tax) was treated as a capital contribution from KeySpan and recorded as an increase to additional paid-in capital during the fourth quarter of 2002.

KeySpan Joint Venture

Effective January 1, 1999, 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 we agreed that KeySpan would 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. Further, KeySpan paid 51.75% of all additional intangible drilling costs incurred and we paid 48.25%. Revenues are shared 55% to Houston Exploration and 45% to KeySpan.

Effective December 31, 2000, KeySpan and Houston Exploration agreed to end the primary or exploratory term of the joint venture. As a result, KeySpan has not participated in any of our offshore exploration prospects unless the project involved the development or further exploitation of discoveries made during the initial term of the joint venture. During 2003, KeySpan spent approximately $9.5 million for capital costs associated with its working interests in properties developed under the joint venture. Costs incurred during 2003 were related to the installation of production facilities at South Timbalier 314/317, the completion of the initial two exploratory wells that were brought on-line during the first quarter of 2003 and participation in a third well, a development well on the property during the second quarter of 2003.

From the inception of the joint venture in January 1999 through December 31, 2003, we drilled a total of 29 wells: 21 exploratory wells, of which 17 were successful, and eight development wells, of which seven were successful. The joint venture had no drilling activity during 2004. KeySpan spent a total of $127.8 million over the course of the joint venture, with less than $100,000 in 2004, and $9.5 million and $19.0 million, respectively being spent during 2003 and 2002.

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Transactions With Our Executive Officers and Directors

Employment Contracts

We have entered into employment contracts with all 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 certain insurance benefits for a specified time period. Subsequent to December 31, 2004, we entered into amended and restated employment agreements with certain executive officers. See Note 11- Subsequent Events.

Lump-Sum Payments to Executives Under Employment Contracts

Pursuant to a management organizational change made within our company in November 2004 that changed the reporting responsibilities of three executive officers, Charles W. Adcock, Senior Vice President and General Manager Offshore Division resigned, effective December 14, 2004, and Timothy R. Lindsey, Senior Vice President of Exploration, and Tracy Price, Senior Vice President Land, resigned, effective March 1, 2005. Pursuant to their resignations and the termination of their employment agreements with our company, we incurred approximately $5.1 million in general and administrative expense of which $1.3 million, $1.1 million and $1.0 million, respectively, related to lump-sum severance entitlements for Messrs. Adcock, Lindsey and Price and, $1.7 million related to expense incurred as a result of the accelerated vesting of all their outstanding stock options and restricted stock.

Transactions Involving Companies with Common Directors

John U. Clarke, a member of our Board of Directors and Chairman of the Audit Committee serves as a Chairman and Chief Executive Officer of NATCO Group, a publicly traded oil field services and equipment company. During 2004, 2003 and 2002 we purchased services and supplies from NATCO of $0.9 million, $1.1 million and $1.1 million, respectively. Mr. Clarke meets all requirements of the New York Stock Exchange to be considered an independent director of our company.

NOTE 7 Derivative Instruments

As of December 31, 2004, we had entered into commodity price hedging contracts with respect to our production for 2005 through 2008 as listed in the tables below. The total estimated fair value of our natural gas and oil derivative instruments at December 31, 2004 was a liability of $75.1 million ($48.5 million net of tax), of which we have deferred a net $46.0 million in accumulated other comprehensive income and recognized $3.9 million ($2.5 net of tax) in earnings as a reduction to natural gas and oil revenues as a result of the estimated ineffectiveness of our open contracts as of the end of the period. From time to time, if the fair value of an open contract or contracts exceeds our available credit limit with a particular counterparty, we could be required to post a letter of credit to further guarantee our performance. As of December 31, 2004, we did not have any outstanding letters of credit issued relating to derivative contracts.

Natural Gas	Fixed Price Swaps		Collars			
	Daily Volume	NYMEX Contract	Daily Volume	NYMEX Contract Price		
Period	**(MMBtu)**	**Price**	**(MMBtu)**	**Floor**	**Ceiling**	**Fair Value**
						(thousands)
January December 2005	80,000	$ 5.304	180,000	$ 4.833	$ 6.434	$ (68,081)
January December 2006	30,000	5.893	60,000	5.500	7.248	(3,889)
January December 2007			30,000	5.000	6.597	(1,662)
January December 2008			20,000	5.000	5.720	(1,517)
						$ (75,149)

As of December 31, 2003, we had entered into commodity price hedging contracts with respect to our production for 2004 and 2005 as listed in the tables below. The total estimated fair value of our natural gas and oil derivative instruments at December 31, 2003 was a liability of $36.9 million ($27.4 million net of tax) of which we had deferred a net $26.1 million

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was in accumulated other comprehensive income and recognized $1.3 million in 2003 earnings as a reduction to natural gas and oil revenues as a result of the estimated ineffectiveness of our open contracts as of the end of the period.

Natural Gas	Options - Puts		Fixed Price Swaps		Collars			
	Daily Volume	NYMEX Contract	Daily Volume	NYMEX Contract	Daily Volume	NYMEX Contract Price		
Period	(MMBtu)	Price	(MMBtu)	Price	(MMBtu)	Floor	Ceiling	Fair Value
								(thousands)
January March 2004	100,000	$ 5.000	40,000	$ 4.960	100,000	$ 3.750	$ 5.045	$ (13,897)
April December 2004			40,000	4.960	200,000	4.125	6.023	(18,238)
January December 2005			50,000	4.766	100,000	4.500	5.500	(4,727)
								$ (36,862)

Fair market value is calculated for the respective months using prices derived from NYMEX futures contract prices existing at December 31st and from market quotes received from counterparties.

For natural gas, transactions are settled based upon 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 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.

NOTE 8 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, 2004, 2003 and 2002 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. Amounts presented in the below table that are less than 10% have been included for information and comparison purposed only.

Major Purchaser	For the Year Ended December 31, 2004	2003	2002

ConocoPhillips	11.9%	18.4%	14.9%
KinderMorgan	10.1%	11.4%	9.8%
Anadarko Petroleum Corporation	9.08%	11.7%	12.6%

NOTE 9 Commitments and Contingencies

Legal Proceedings

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.

Severance Tax Refund

During July 2002, we applied for and received from the Railroad Commission of Texas a high-cost/tight-gas formation designation for a portion of our South Texas production. For qualifying wells, production is either exempt from tax or taxed at a reduced rate until certain capital costs are recovered. For the years ended December 31, 2004 and 2003, we recognized as other income refunds of prior period severance tax payments of $1.2 million and $21.6 million, respectively. For the year ended December 31, 2002, we recognized a total of $10.4 million, of which $1.3 million related to refund of 2002 severance tax expense and $9.1 related to refunds of prior period expense. At December 31, 2004, and 2003, our current receivables include $1.3 million and $12.9 million, respectively, in gross refunds of which we estimate, approximately 70%, or $0.9 million and $9.0 million, respectively, relate to our net revenue interest. We expect to collect

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our current receivable prior to the end of the third quarter of 2005. Beginning September 1, 2003, all refunds issued by the State of Texas are to be made in the form of a reduction to or credit against our current severance tax liability rather than in the form of a cash reimbursement.

Leases

We have entered into non-cancelable operating lease agreements in the ordinary course of our business activities. These leases include those for our office space at 1100 Louisiana in Houston, Texas and at 700 17th Street in Denver, Colorado together with various types of office equipment (telephones, copiers and faxes). The terms of these agreements have various expiration dates from 2005 through 2009. Rental expense related to these leases was $1.6 million, $1.3 million and $1.2 million, respectively, for the years ended December 31, 2004, 2003 and 2002. At December 31, 2004, our total commitment under these non-cancelable operating leases was $7.2 million. Minimum rental commitments under the terms of our operating leases are as follows (in thousands):

Years Ended December 31,	**Minimum Payments**
2005	$ 1,550
2006	1,536
2007	1,593
2008	1,611
2009	933
Thereafter	
Total	$ 7,223

NOTE 10 Acquisitions and Dispositions (Reserve quantities, wells, acreage and working interests included below are unaudited.)

Orca Acquisition

On October 29, 2004, we completed the acquisition of certain producing properties from Orca Energy, L.P. The $113.6 purchase price was paid in cash and financed by borrowings under our revolving bank credit facility. The transaction was effective August 1, 2004. The Orca properties consist of 10 offshore blocks and two onshore fields. The onshore fields are non-operated and located in central Mississippi: the Wausau Field, located in Wayne County and the Oakvale Dome Field, located in Jefferson Davis County. The 10 offshore blocks are a mix of state and federal leases, located in less than 50 feet of water, and include seven blocks in federal waters and three blocks in state waters. Total acreage acquired covers 23,777 gross (17,973 net) acres. The properties include 15 platforms, five production caissons and 28 producing wells. Based on internal estimates, total proved reserves acquired were approximately 60.7 Bcfe as of the closing date, October 29, 2004, of which 81% were natural gas. Our average working interest in the properties acquired is 68% and we will operate approximately 85% of the proved reserves acquired.

BP Acquisition

On September 30, 2004, we completed the purchase of two producing offshore fields from BP Exploration & Production Inc. The net purchase price of $30.0 million was paid in cash and financed by borrowings under our revolving bank credit facility. The $31.5 million purchase price was reduced by $1.5 million for various customary closing items, including revenues received by and expenditures made by the seller related to the properties acquired for the period between the effective date of the transaction, August 1, 2004, and the closing date, September 30, 2004. The properties acquired are located at Eugene Island 240 and Main Pass 264 and each block has one producing platform. Based on internal estimates, total proved reserves associated with the interests acquired were approximately 16.2 Bcfe as of September 30, 2004, of which 85% are natural gas. Our average working interest is 85% and we will operate both blocks.

Disposition and Exchange of Appalachian Basin Assets

In connection with the KeySpan Exchange on June 2, 2004, (see Note 1 *KeySpan Exchange and Offering*) we divested all of our Appalachian Basin assets with an agreed upon value of $60 million. Pursuant to an Asset Contribution Agreement, we contributed to Seneca-Upshur all of the assets relating solely to our Appalachian Basin assets that were not already owned by Seneca-Upshur, and Seneca-Upshur assumed all of the liabilities relating to the Appalachian Basin assets for

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which it was not already liable. In the KeySpan Exchange, all of the stock of Seneca-Upshur was then conveyed to KeySpan and effective June 1, 2004, Seneca-Upshur became an indirect wholly-owned subsidiary of KeySpan.

Our Appalachian property base was located primarily in central West Virginia and included the Belington, Clarksburg and Seneca Upshur Fields located in Barbour, Randolph, Upshur and Mingo Counties of West Virginia. Included in the assets exchanged were the assets acquired on December 31, 2003, from EnerVest East Limited Partnership located adjacent to our existing base in the Crawford and Pennsboro Fields in Lewis, Harrison, Tyler and Ritchie Counties of West Virginia and the Waynesburg and Yatesboro Fields in Greene and Armstrong Counties of southwestern Pennsylvania. Based on internal estimates at June 1, 2004, our Appalachian Basin properties had 51.2 Bcfe of estimated proved reserves, and our average daily production was approximately 8 MMcfe/day, which represented approximately 3% of our total daily production. We had approximately 207,000 gross (129,000 net) acres under lease and owned working interests in approximately 1,414 gross (1,035 net) wells, of which we operated approximately 92%. Our average working interest was 73%.

Sale of Onshore South Louisiana Properties

On February 4, 2004, we completed the sale of our onshore South Louisiana producing properties. The sale was effective November 1, 2003, and the properties represented 12.3 Bcfe proved reserves as of December 31, 2003, and included interests in 33 gross (9.5 net) producing wells and covered approximately 6,300 gross (2,300 net) acres. The sale price of $15 million was reduced by $1.9 million for various customary closing items, including revenues received by and expenditures made by us related to the properties sold for the period between the effective date of the transaction and the closing date. The net proceeds of $13.1 million from the sale were used to repay borrowings under our revolving bank credit facility.

EnerVest Acquisition

On December 31, 2003, we completed the purchase of certain producing natural gas and oil properties and associated gathering pipelines and equipment located in the Appalachian Basin of West Virginia and Pennsylvania from EnerVest East Limited Partnership. The properties acquired are adjacent to our existing producing properties in West Virginia. The $28 million purchase price was reduced by $0.2 million for various customary closing items, including revenues received by and expenditures made by the seller related to the properties acquired for the period between the effective date of the transaction, December 1, 2003, and the closing date, December 31, 2003. The net purchase price of $27.9 million was paid in cash and financed by borrowings under our revolving bank credit facility. The properties purchased cover approximately 146,000 gross (83,950 net) acres. The properties acquired include working interests in approximately 774 producing wells Our average working interest is 74% and we will we operate approximately 85% of the wells acquired. In addition, the interests acquired include approximately 300 wells in which we will have an overriding royalty interest. Total proved reserves associated with the interests acquired were 23.4 Bcfe, as of the December 31, 2003.

Transworld Exploration and Production Inc. Acquisition

On October 15, 2003, we completed the acquisition of Transworld Exploration and Production Inc. s shallow-water Gulf of Mexico natural gas and oil producing properties and undeveloped acreage. At closing, the $155 million purchase price was reduced by $7.5 million for various customary closing items, including revenues received by and expenditures made by the seller related to the properties acquired for the period between the effective date of the transaction, July 1, 2003, and the closing date, October 15, 2003. The net purchase price of $147.5 million was paid in cash and financed in part by cash on hand and in part by borrowings under our revolving bank credit facility. The properties are located primarily in the central Gulf of Mexico in less than 320 feet of water and include 21 blocks covering 86,237 gross (64,394 net) acres. As of the October 15, 2003 closing date, proved reserves are an estimated 88.5 Bcfe, of which 75% is natural gas. Current production is from 11 fields and is estimated at approximately 35 MMcfe per day, net to our interest. We operate properties representing 97% of the proved reserves with an average working interest of 65%.

Acquisition of KeySpan Joint Venture Assets (See Note 6 Related Party Transaction Transactions with KeySpan)

Burlington Acquisition

On May 30, 2002, we completed the purchase of natural gas and oil producing properties and associated gathering pipelines, together with undeveloped acreage, from Burlington Resources Inc. located in the Webb, Jim Hogg, Wharton and Calhoun counties of South Texas. The properties purchased cover approximately 24,800 gross (10,800 net) acres located in

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the Northeast Thompsonville, South Laredo, McFarlan and Maude Traylor Fields. The properties purchased represent interests in approximately 145 producing wells and total proved reserves of 42 Bcfe as of January 1, 2002, the effective date of the transaction. Our average working interest is 35% and we are the operator of approximately 23% of the producing wells acquired. The $44.5 million purchase price, which is net of a purchase price adjustment of $3.9 million, was financed by borrowings under our revolving bank credit facility. The purchase price was reduced for various closing items in the normal course of business, including revenues received by and expenditures made by the seller related to the properties acquired for the period between the effective date of the transaction (January 1, 2002) and the closing date (May 30, 2002).

On July 16, 2002, we sold those interests acquired from Burlington in the McFarlan and Maude Traylor Fields for approximately $5.0 million, which was net of a purchase price adjustment of $1.1 million. The effective date of this transaction was January 1, 2002. These two fields, located in Wharton and Calhoun counties, respectively, are outside our current area of focus in South Texas. The sale represented interests in 22 producing wells with reserves of approximately 5 Bcfe. Proceeds from the sale were used to repay borrowings under our revolving bank credit facility.

We retained the Northeast Thompsonville Field, located in Jim Hogg County, and the South Laredo Field, located in Webb County. The Northeast Thompsonville Field has 10 wells producing from the Wilcox formation, all of which we operate, and representing approximately 70% of the proved reserves and 75% of the current production associated with the acquisition from Burlington. The South Laredo Field, located in Webb County and in the Lobo Trend, contains 113 wells, all operated by a third party.

Conoco Acquisition

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 on December 31, 2001. 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%. Total proved reserves associated with the interests acquired were 85 Bcfe, as of the October 1, 2001, the effective date of the transaction.

NOTE 11 Subsequent Events

Proposed Increase in Number of Shares Outstanding

Our Board of Directors intends to seek shareholder approval at the next annual meeting in April 2005, to increase the number of shares we are authorized to issue to up to 105,000,000 shares of stock, including up to 100,000,000 shares of common stock and up to 5,000,000 shares of preferred stock.

Amendments to Employment Agreements

Effective February 8, 2005, we entered into amended and restated employment agreements with William G. Hargett, our President and Chief Executive Officer, Steven L. Mueller, our Executive Vice President and Chief Operating Officer, John H. Karnes, our Senior Vice President and Chief Financial Officer, James F. Westmoreland, our Vice President and Chief Accounting Officer, and Roger B. Rice, our Senior Vice President-Administration. We also entered into a new employment agreement with Joanne C. Hresko, our Vice President and General Manager-Onshore Division. Each agreement is for a term of three years, with automatic one-year extensions thereafter unless we or the executive provide notice of termination at least 90 days prior to the end of the applicable term.

By entering into the amended and restated employment agreements and terminating their prior employment agreements with us, Messrs. Hargett, Mueller, Karnes, Westmoreland and Rice are foregoing certain rights, including the right to receive severance for a termination of employment following a change of control of the Company absent the existence of good reason and the right to guaranteed annual stock option grants and incentive compensation bonuses, which will now be subject to the discretion of our Compensation and Management Development Committee. In addition to these rights, Mr. Hargett also is foregoing the right to receive a transaction bonus upon the occurrence of certain corporate transactions involving the Company, and all of the executives are agreeing to somewhat broader non-competition provisions under the

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amended and restated agreements. In consideration of their entering into the amended and restated agreements and foregoing such rights, we have agreed to pay to each of these executives cash and/or restricted stock. The restricted stock will vest over a period of five years in accordance with the terms of our 2004 Long-Term Incentive Compensation Plan.

All of the new agreements provide that if we terminate an executive s agreement without cause (as defined in the employment agreement), or if the executive terminates his or her employment with us for good reason (as defined in the agreement, which includes the occurrence of certain events following a change in control of the Company), we are obligated to pay the executive a lump-sum severance payment equal to 2.99 times his or her then current annual rate of total compensation, and to continue certain welfare benefits. The agreements further provide that if any payments made to the executives, whether or not under the agreement, would result in an excise tax being imposed on the executives under Section 4999 of the Internal Revenue Code, we will make each of the executives whole on a net after-tax basis.

We may terminate any employment agreement for cause or upon the death or disability of the executive without financial obligation (other than payment of any accrued obligations). Each executive may terminate his or her employment agreement at any time for any reason upon at least 30 days prior written notice. In the event the executive s employment is terminated by us without cause or upon death or disability, or if the executive terminates his or her employment with us for good reason, any unvested shares of restricted stock, unvested options or similar deferred compensation automatically will vest and any other conditions to such awards shall be deemed satisfied.

During the first quarter of 2005, we expect to incur additional general and administrative expense of approximately $5.1 million as a result of our terminating the prior employment agreements for Messrs. Hargett, Mueller, Karnes, Westmoreland and Rice.

Appointment of Thomas A. McKeever as Director

Effective February 1, 2005, our Board of Directors appointed Thomas A. McKeever to serve as a director. Mr. McKeever will stand for election at the Company s Annual Meeting to be held April 26, 2005. Mr. McKeever is not a party to any transaction described in Item 404(a) of Regulation S-K involving the Houston Exploration. With the appointment of Mr. McKeever, Houston Exploration s Board was increased from seven to eight members. Mr. McKeever is expected to serve on our Compensation and Management Development Committee, effective as of the date of our 2005 annual meeting.

Termination of Employment Agreements

On February 17, 2005, Timothy R. Lindsey, Senior Vice President of Exploration, and Tracy Price, Senior Vice President Land, resigned from the company, effective March 1, 2005. Their resignations were prompted by our management organizational change made in November 2004 in which they were given new reporting responsibilities. Upon resignation, their employment agreements will be terminated and each is entitled to receive a lump-sum severance payment in the amount of 2.99 times his total compensation, the continuation of certain health and medical benefits for a period of at least 12 months and accelerated vesting of all outstanding stock options and restricted stock. During the fourth quarter of 2004, we recognized additional general and administrative expense of $3.1 million relating to the entitlements under these employment agreements.

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.

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Capitalized Costs of Natural Gas and Oil Properties

	As of December 31, 2004	2003	2002
		(in thousands)	
Unevaluated properties, not subject to amortization	$ 122,691	$ 134,491	$ 96,192
Properties subject to amortization	2,705,897	2,252,852	1,828,160
Asset retirement obligations [(1)]	71,200	71,159	
Capitalized costs	2,899,788	2,458,502	1,924,352
Accumulated depreciation, depletion and amortization	(1,355,857)	(1,092,073)	(906,089)
Net capitalized costs	$ 1,543,931	$ 1,366,429	$ 1,018,263

(1) For 2002, our presentation does not include asset retirement obligations as we adopted SFAS 143 Asset Retirement Obligations on January 1, 2003.

Additions to Unevaluated Properties

The following table provides a summary of unevaluated costs not being amortized as of December 31, 2004, by the year in which the costs were incurred. There are no individually significant properties or significant development projects included in our unevaluated property balance. We estimate that costs will be evaluated within four years.

	Costs incurred by Year as of December 31, 2004 Total	2004	2003	2002	2001 and Prior
			(in thousands)		
Property acquisition costs	$ 90,049	$ 23,170	$ 44,036	$ 8,909	$ 13,934
Exploration and development	22,128	11,191	397	7,588	2,952
Capitalized interest	10,514	6,723	3,791		
Total	$ 122,691	$ 41,084	$ 48,224	$ 16,497	$ 16,886

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, 2004, 2003 and 2002 include interest expense and general and administrative costs related to acquisition, exploration and development of natural gas and oil properties of $23.2 million, $20.2 million and $21.1 million, respectively. During the years ended December 2004, 2003 and 2002, we spent $56.7 million, $46.0 million and $11.0 million, respectively, to develop our proved undeveloped reserves.

As of December 31,

	2004	2003	2002
		(in thousands)	
Property acquisition and leasehold costs			
Unevaluated	$ 28,059	$ 61,224	$ 14,600
Proved	179,281	170,272	89,873
Exploration costs	63,646	66,259	26,563
Development costs	245,971	162,235	122,036
	516,957	459,990	253,072
Asset retirement obligations costs assumed[1]	12,116	31,652	
Asset retirement obligations costs properties sold[1]	(12,714)		
Asset retirement expenditures[1]	(2,362)		
Total costs incurred	$ 513,997	$ 491,642	$ 253,072

(1) Asset retirement obligation costs reflect abandonment obligations assumed during the year and revisions to prior estimates. As a result of the disposition of our South Louisiana and Appalachian Basin assets during 2004, asset retirement obligations were reduced by $12.7 million. Actual retirement expenditures reflect plugging and abandonment costs during the year. For 2003, our presentation of asset retirement obligation costs incurred does not include the cumulative effect of adopting SFAS 143 Asset Retirement Obligations on January 1, 2003 of $42.5 million (see Note 1 Summary of Organization and Accounting Policies - *Asset Retirement Obligations*).

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

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 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%.

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,		
	2004	**2003**	**2002**
		(in thousands)	
Future cash inflows	$ 4,558,560	$ 4,335,669	$ 2,845,768
Future production costs	(812,800)	(764,373)	(486,399)
Future development costs	(545,192)	(369,121)	(241,876)

Future income taxes	(976,611)	(850,264)	(542,782)
Future net cash flows	2,223,957	2,351,911	1,574,711
10% annual discount for estimated timing of cash flows	(783,902)	(847,505)	(516,647)
Standardized measure of discounted future net cash flows	$ 1,440,055	$ 1,504,406	$ 1,058,064

At December 31, 2004, our Standardized Measure of Discounted Future Net Cash Flows includes estimated future development costs for our proved undeveloped reserves for the next three years of $229.7 million, $127.7 million, and $9.5 million, respectively, for 2005, 2006 and 2007.

Present Value of Future Net Cash Flows Relating to Proved Natural Gas and Oil Reserves

The present value of future net cash flows attributable to estimated net proved reserves, discounted at 10% per annum, (PV10) is a computation of the Standardized Measure of Discounted Future Net Cash Flows on a pre-tax basis. The table below provides a reconciliation of PV10 to the Standardized Measure of Discounted Future Net Cash Flows. PV10 may be considered a non-GAAP financial measure as defined by the SEC s Regulation G. We consider PV10 to be an important

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measure for evaluating the relative significance of our natural gas and oil properties. PV10 is computed on the same basis as the Standardized Measure of Discounted Future Net Cash Flows but without deducting income taxes. We believe investors and creditors may utilize our PV10 as a basis for comparison of the relative size and value of our reserves to other companies. However, PV10 is not a substitute for the standardized measure. Our PV10 measure and the Standardized Measure of Discounted Future Net Cash Flows do not purport to present the fair value of our natural gas and oil reserves.

	As of December 31,		
	2004	2003	2002
		(in thousands)	
Net present value of future cash flows, before income taxes	$ 2,071,976	$ 2,056,414	$ 1,364,921
Future income taxes, discounted at 10%	(631,921)	(552,008)	(306,857)
Standardized measure of discounted future net cash flows	$ 1,440,055	$ 1,504,406	$ 1,058,064

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

	As of December 31,		
	2004	2003	2002
		(in thousands)	
Beginning of the year	$ 1,504,406	$ 1,058,064	$ 551,525
Revisions to previous estimates:			
Revisions in quantities	(59,549)	(123,954)	(36,368)
Changes in prices	(34,170)	459,373	629,542
Changes in future development costs	(35,056)	(13,029)	(1,970)
Development costs incurred during the period	85,439	72,717	23,393
Extensions and discoveries, net of related costs	445,908	434,311	242,055
Sales of natural gas and oil, net of production costs	(639,555)	(486,382)	(275,157)
Accretion of discount	205,641	136,492	64,858
Net change in income taxes	(79,913)	(245,151)	(209,807)
Purchase of reserves in place	247,671	254,030	99,741
Sale of reserves in place	(110,877)		(170)
Production timing and other	(89,890)	(42,065)	(29,578)
End of year	$ 1,440,055	$ 1,504,406	$ 1,058,064

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Estimated Net Quantities of Natural Gas and Oil Reserves

The following table sets forth our 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, 2004, 2003 and 2002.

	Natural Gas (MMcf)			Crude Oil, Liquids and Condensate (MBbls)		
	2004	**2003**	**2002**	**2004**	**2003**	**2002**
Beginning of the year reserves	709,883	610,409	568,208	7,481	6,533	6,605
Revisions of previous estimates	(13,232)	(30,573)	(14,863)	(1,110)	(1,615)	(26)
Extensions and discoveries	162,719	140,632	105,798	255	117	342
Production	(115,855)	(99,965)	(97,368)	(1,355)	(1,307)	(859)
Purchase of reserves in place	67,806	89,380	48,777	2,245	3,753	483
Sales of reserves in place	(62,207)		(143)	(181)		(12)
End of year reserves	749,114	709,883	610,409	7,335	7,481	6,533
Proved developed reserves:						
Beginning of year	487,867	435,629	438,538	4,073	2,413	2,123
End of year	475,080	487,867	435,629	3,535	4,073	2,413

	Natural Gas Equivalents (MMcfe)		
	2004	**2003**	**2002**
Beginning of year reserves	754,769	649,607	607,838
Revisions of previous estimates	(19,892)	(40,263)	(15,019)
Extensions and discoveries	164,249	141,334	107,850
Production	(123,985)	(107,807)	(102,522)
Purchase of reserves in place	81,276	111,898	51,675
Sales of reserves in place	(63,293)		(215)
End of year reserves	793,124	754,769	649,607
Proved developed reserves:			
Beginning of year	512,305	450,107	451,276
End of year	496,290	512,305	450,107

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NOTE 13 Quarterly Financial Information (Unaudited)

The following represents our unaudited quarterly results for years ended December 31, 2004 and 2003. There quarterly results were prepared in accordance with GAAP and reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results. These adjustments are of a normal recurring nature.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2004				
Total revenues	$ 151,882	$ 172,776	$ 162,760	$ 163,021
Total operating expenses [1]	86,839	97,702	94,366	103,719
Income from operations	65,043	75,074	68,394	59,302
Net income	39,690	45,350	42,998	34,786
Net income per share basic [2]	$ 1.26	$ 1.49	$ 1.53	$ 1.23
Net income per share diluted [2]	$ 1.25	$ 1.47	$ 1.51	$ 1.21
2003				
Total revenues	$ 129,003	$ 120,632	$ 118,887	$ 124,230
Total operating expenses	68,807	70,341	69,856	85,153
Income from operations	60,196	50,291	49,031	39,077
Income before cumulative effect of change in accounting principle	44,469	28,923	34,719	25,701
Cumulative effect of change in accounting principle	(2,772)			
Net income	41,697	28,923	34,719	25,701
Net income per share basic:				
Income before cumulative effect of change in accounting principle	$ 1.44	$ 0.93	$ 1.12	$ 0.82
Cumulative effect of change in accounting principle	(0.09)			
Net income per share basic [2]	$ 1.35	$ 0.93	$ 1.12	$ 0.82
Net income per share diluted:				
Income before cumulative effect of change in accounting principle	$ 1.43	$ 0.93	$ 1.11	$ 0.82
Cumulative effect of change in accounting principle	(0.09)			
Net income per share diluted [2]	$ 1.34	$ 0.93	$ 1.11	$ 0.82

(1)

As a result of management organizational changes made within our company in November 2004, we recognized additional general and administrative expense of $5.1 million during the fourth quarter of 2004. The additional compensation expenses were a result of lump-sum severance payments and entitlements under executive employment agreements, including expenses related to the accelerated vesting of stock options and restricted stock. See Note 11 Subsequent Events *Termination of Employment Agreements*.

(2) Quarterly earnings per share is based on the weighted average number of shares outstanding during the quarter. Because of changes in the number of shares outstanding during the quarters due to the exercise of stock options and/or the issuance or repurchase of common stock, the sum of quarterly earnings per share may not equal earnings per share for the year.

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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 June 10, 2003, between The Houston Exploration Company and the Bank of New York, as Trustee, with respect to the 7% Senior Subordinated Notes due 2013 (filed as Exhibit 4.2 to our Registration Statement on Form S-4 (Registration No. 333-106836) and incorporated by reference).
10.1	Rights Agreement, dated as of August 12, 2004, between The Houston Exploration Company and The Bank of New York, as Rights Agent (filed as Exhibit 4.1 to our Current Report on Form 8-K dated August 13, 2004 (File No. 001-11899) and incorporated by reference).
10.2	Registration Rights Agreement dated as of June 5, 2003, among The Houston Exploration Company and Wachovia Securities, Inc., Lehman Brothers Inc., BNP Paribas Securities Corp., Fleet Securities, Inc. and Scotia Capital (USA) Inc., as Initial Purchasers (filed as Exhibit 4.5 to our Registration Statement on Form S-4 (Registration No. 333-106836) and incorporated by reference).
10.3	Amended and Restated Registration Rights Agreement dated as of June 2, 2004 between The Houston Exploration Company and THEC Holdings Corp. (filed as Exhibit 99.6 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).
10.4	Form of Certificate of Designation of Series A Junior Participation Preferred Stock of The Houston Exploration Company (filed as Exhibit 4.2 to our Current Report on Form 8-K dated August 13, 2004 (File No. 001-11899) and incorporated by reference).
10.5	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).
10.6	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).
10.7	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 Report on Form 10-Q for the quarter ended September 30, 2000 (File No. 001-11899) 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)]	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).
10.10[(2)]	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).
10.11[(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).

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INDEX TO EXHIBITS

EXHIBITS	DESCRIPTION
10.12(2)	Executive Deferred Compensation Plan dated January 1, 2002 (filed as Exhibit 10.28 to our Annual Report on Form 10-K for the year ended December 31, 2002 (File No. 001-11899) and incorporated by reference).
10.13(2)	Amended and Restated 2002 Long-Term Incentive Plan effective May 17, 2002, adopted October 26, 2003 (filed as Exhibit 10.31 to our Annual Report on Form 10-K for the year ended December 31, 2003 (file No. 001-11899) and incorporated by reference).
10.14(2)	2004 Long Term Incentive Plan approved by vote of stockholders on June 3, 2004 (filed as Appendix E to our Definitive Proxy Statement on Schedule 14 A dated June 3, 2004 (File No. 001-11899) and incorporated by reference).
10.16(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) and incorporated by reference).
10.17(2)	Employment Agreement dated September 29, 2003 between The Houston Exploration Company and Timothy R. Lindsey (filed as Exhibit 10.3 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2003 (File No. 001-11899) and incorporated by reference).
10.18(2)	Amended and Restated Employment Agreement dated February 8, 2005 between The Houston Exploration Company and William G. Hargett (filed as Exhibit 10.1 to our Current Report on Form 8-K dated February 8, 2005 (File No. 001-11899) and incorporated by reference).
10.19(1)(2)	Amended and Restated Employment Agreement between The Houston Exploration Company and Steven L. Mueller dated February 8, 2005.
10.20(1)(2)	Amended and Restated Employment Agreement between The Houston Exploration Company and John H. Karnes February 8, 2005.
10.21(1)(2)	Amended and Restated Employment Agreement between The Houston Exploration Company and James F. Westmoreland dated February 8, 2005.
10.22(1)(2)	Amended and Restated Employment Agreement between The Houston Exploration Company and Roger B. Rice dated February 8, 2005.
10.23(2)	Employment Agreement dated February 10, 2005 between The Houston Exploration Company and Joanne C. Hresko (filed as Exhibit 10.3 to our Current Report on Form 8-K dated February 8, 2005 (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	Amended and Restated Credit Agreement dated April 1, 2004 among The Houston Exploration Company and Wachovia Bank, National Association, as Issuing Bank and Administrative Agent; The Bank of Nova Scotia and Fleet National Bank as Co-Syndication Agents; and BNP Paribas and Comerica Bank as Co-Documentation Agents (filed as Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2004 (File No. 001-11899) and incorporated by reference).
10.26	First Amendment dated May 26, 2004 to the Amended and Restated Credit Agreement dated April 1, 2004 among The Houston Exploration Company and Wachovia Bank, National Association, as Issuing Bank and Administrative Agent; The Bank of Nova Scotia and Fleet National Bank as Co-Syndication Agents; and BNP Paribas and Comerica Bank as Co-Documentation Agents dated June 2, 2004 (filed as Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 (File No. 001-11899) and incorporated by reference).

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INDEX TO EXHIBITS

EXHIBITS	DESCRIPTION
10.27	Purchase and Sale Agreement, dated September 3, 2003, by and among Transworld Exploration and Production, Inc., as Seller, and The Houston Exploration Company, as Buyer (Exhibit 2.1 to Current Report on Form 8-K dated October 15, 2003 (file No. 001-11899) and incorporated by reference).
10.28	Purchase and Sale Agreement, dated September 17, 2004, between The Houston Exploration Company and Orca Energy, L.P. (filed as Exhibit 2.1 to our Current Report on Form 8-K dated November 1, 2004 (File No. 001-11899) and incorporated by reference).
10.29	Distribution Agreement dated as of June 2, 2004 by and among The Houston Exploration Company, Seneca-Upshur Petroleum, Inc., THEC Holdings Corp. and KeySpan Corporation (filed as Exhibit 99.2 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).
10.30	Asset Contribution Agreement dated June 2, 2004 between The Houston Exploration Company and Seneca-Upshur Petroleum, Inc. (filed as Exhibit 99.3 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).
10.31	Tax Matters Agreement dated as of June 2, 2004 by and among The Houston Exploration Company, Seneca-Upshur Petroleum, Inc., THEC Holdings Corp., and KeySpan Corporation (filed as Exhibit 99.4 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).
10.32	Transition Service Agreement dated June 2, 2004 between The Houston Exploration Company and Seneca-Upshur Petroleum, Inc. (filed as Exhibit 99.4 to our Current Report on Form 8-K dated June 30, 2004 (File No. 001-11899) and incorporated by reference).
10.33(2)	Form of waiver to employment agreement between The Houston Exploration Company and its executive officers allowing restricted stock awards in addition to stock option awards (filed as Exhibit 10.4 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2004 (File No. 001-11899) and incorporated by reference).
10.34(1)(2)	Compensation table for Officers and Directors.
12.1(1)	Computation of ratio of earnings to fixed charges.
23.1(1)	Consent of Deloitte & Touche LLP.
23.2(1)	Consent of Netherland, Sewell & Associates.
23.3(1)	Consent of Miller and Lents.
31.1(1)	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2[(1)]	Certification of John H. Karnes, Chief Financial Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1[(1)]	Certification of William G. Hargett, Chief Executive Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2[(1)]	Certification of John H. Karnes, Chief Financial Officer, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(1) Filed herewith.

(2) Management contract or compensation plan.