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

FORM 10-K

☒ Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the Fiscal Year Ended December 31, 2004

☐ Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Commission File No. 1-13726

Chesapeake Energy Corporation
(Exact Name of Registrant as Specified in Its Charter)

Oklahoma **(State or other jurisdiction of incorporation or organization)**	**73-1395733** **(I.R.S. Employer Identification No.)**
6100 North Western Avenue **Oklahoma City, Oklahoma** **(Address of principal executive offices)**	**73118** **(Zip Code)**

(405) 848-8000
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, par value $.01	New York Stock Exchange
8.375% Senior Notes due 2008	New York Stock Exchange
8.125% Senior Notes due 2011	New York Stock Exchange
9.0% Senior Notes due 2012	New York Stock Exchange
7.5% Senior Notes due 2013	New York Stock Exchange
7.0% Senior Notes due 2014	New York Stock Exchange
7.5% Senior Notes due 2014	New York Stock Exchange
7.75% Senior Notes due 2015	New York Stock Exchange
6.875% Senior Notes due 2016	New York Stock Exchange
6.0% Cumulative Convertible Preferred Stock	New York Stock Exchange
5.0% Cumulative Convertible Preferred Stock	New York Stock Exchange

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

None

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

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

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2004 was $3,229,393,436. At March 2, 2005, there were 314,122,017 shares of common stock issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2005 Annual Meeting of Shareholders are incorporated by reference in Part III.

PART I

ITEM 1. *Business*

General

We are one of the four largest independent producers of natural gas in the U.S. and own interests in approximately 20,000 producing oil and gas wells. Our proved oil and natural gas reserves as of December 31, 2004 were approximately 4.9 tcfe. At December 31, 2004, approximately 89% of our proved reserves (by volume) were natural gas, and approximately 70% of our proved oil and natural gas reserves were located in our primary operating area-the Mid-Continent region of the United States, which includes Oklahoma, western Arkansas, southwestern Kansas and the Texas Panhandle. In addition, we are building significant secondary operating areas in the South Texas and Texas Gulf Coast region, the Permian Basin of western Texas and eastern New Mexico and in the Ark-La-Tex area of central and eastern Texas and northern Louisiana.

From January 1, 1998 through December 31, 2004, we have been one of the most active consolidators of onshore U.S. natural gas assets, having purchased approximately 3.8 tcfe of proved reserves at a total cost of approximately $4.5 billion (excluding $851 million of unproved properties as well as $558 million of deferred taxes in connection with certain corporate acquisitions).

During 2004, we remained active in the acquisitions market. Acquisition expenditures totaled $2.0 billion in 2004 (excluding $464 million of deferred taxes in connection with certain corporate acquisitions). Through our completed 2004 acquisitions, we acquired an internally estimated 1,137 bcfe of proved oil and natural gas reserves at a cost of $1.36 per mcfe (excluding $0.41 per mcfe of deferred taxes in connection with certain corporate acquisitions).

During 2004, we drilled 561 (425 net) operated wells and participated in another 890 (121 net) wells operated by other companies. The company's success rate was 96% for both operated and non-operated wells. Through our exploration and development operations, we added approximately 962 bcfe of proved oil and gas reserves. As of December 31, 2004, our proved developed producing reserves were 66% of our total proved reserves. In 2004, we invested $299.8 million in leasehold (exclusive of leases acquired through acquisitions) and 3-D seismic data.

Our principal executive offices are located at 6100 North Western Avenue, Oklahoma City, Oklahoma 73118 and our main telephone number at that location is (405) 848-8000. We make available free of charge on our website at *www.chkenergy.com* our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. References to "us", "we" and "our" in this report refer to Chesapeake Energy Corporation together with its subsidiaries.

Recent Developments

On January 28, 2005, we amended and restated our revolving bank credit facility, increasing the borrowing base to $1.25 billion and extending the maturity to January 2010.

On February 1, 2005, we acquired Mid-Continent and Ark-La-Tex natural gas and oil assets through the purchase of the stock of BRG Petroleum Corporation and the acquisition of various other partnership interests for cash consideration of approximately $325 million, of which $16.3 million was paid in 2004.

Business Strategy

Since the company's inception in 1989, our goal has been to create value for our investors by building one of the largest onshore natural gas resource bases in the United States. For the past seven years, our strategy to accomplish this goal has been to build the dominant operating position in the Mid-Continent region, the third largest gas supply region in the U.S. In building this industry-leading position in the Mid-Continent, we have integrated an aggressive and technologically advanced drilling program with an active property consolidation program focused on small to medium-sized corporate and property acquisitions of up to $600 million. We are now building significant secondary operating areas in the South Texas and Texas Gulf Coast region, Permian Basin and Ark-La-Tex area. We believe significant elements of our successful Mid-Continent strategy can be transferred to these areas.

Key elements of this business strategy are further explained below:

- *Make High-Quality Acquisitions.* Our acquisition program is focused on small to medium-sized acquisitions of natural gas properties that offer high-quality, long-lived production and significant development and higher potential deep drilling opportunities. From January 1, 1998 through December 31, 2004, we have acquired $4.5 billion of such proved properties (largely through 48 separate transactions of greater than $10 million each) at an estimated average cost of $1.18 per mcfe of proved reserves (excluding $0.15 per mcfe of deferred taxes in connection with certain corporate acquisitions). The vast majority of these acquisitions either increased our ownership in existing wells or fields or added additional drilling locations in the Mid-Continent, and more recently in our secondary operating areas. Because our operating areas contain many small companies seeking liquidity opportunities and larger companies seeking to divest non-core assets, we expect to continue to find additional attractive acquisition opportunities in the future.
- *Grow through the Drillbit.* One of our most distinctive characteristics is our ability to increase reserves and production through the drillbit. We are currently utilizing 68 operated drilling rigs and 62 non-operated drilling rigs to conduct what we believe is the most active drilling program in the United States. We focus on both finding significant new natural gas reserves and developing existing proved reserves, principally at deeper depths than the industry average. For the past seven years, we have been aggressively investing in the leasehold, 3-D seismic information and human capital to be able to take advantage of the favorable drilling economics that exist in our industry today. While U.S. natural gas production has been declining during the past few years, we are one of the few mid- to large-cap companies that have been able to increase production, as we have successfully done for the past 15 years and 14 consecutive quarters. In the Mid-Continent, our drilling program remains the most active in the region and is supported by our ownership of the region's largest leasehold and 3-D seismic inventories. Across our operating areas, we seek a balanced approach to drilling, with approximately one-third of our expenditures focused on targets located at depths shallower than 10,000 feet, one-third on medium depth drilling between 10,000 – 15,000 feet and one-third targeting deeper objectives below 15,000 feet.
- *Build Regional Scale.* We believe one of the keys to success in the natural gas exploration industry is to build significant operating scale in a limited number of operating areas. Achieving such scale provides many benefits, the most important of which are higher per unit revenues, lower per unit operating costs, greater rates of drilling success, higher returns from more easily integrated acquisitions and higher returns on drilling investments. We first began pursuing this focused strategy in the Mid-Continent in 1997 and we are now the largest natural gas producer, the most active driller and the most active acquirer of leasehold and producing properties in the Mid-Continent. We believe this region, which trails only the Gulf Coast and Rocky Mountain basins in current U.S. gas production, has many attractive characteristics. These characteristics include long-lived natural gas properties with predictable decline curves; multi-pay geological targets that decrease drilling risk and have resulted in a drilling success rate of 92% over the past fifteen years; favorable basis differentials to benchmark commodity prices; generally lower service costs than in more competitive or more remote basins; and a favorable regulatory environment with virtually no federal land ownership. We believe our secondary operating areas possess many of these same favorable characteristics.
- *Focus on Low Costs.* By minimizing lease operating costs and general and administrative expenses through focused activities and increased scale, we have been able to deliver attractive financial returns

through all phases of the commodity price cycle. We believe our low cost structure is the result of our management's effective cost-control programs, a high-quality asset base and the extensive and competitive services, gas processing and transportation infrastructures that exist in our key operating areas. We believe our acquisitions in 2004 will help maintain our low per unit operating and administrative costs because of our large existing scale of operations and the reimbursements we will receive from third parties in the approximately 2,800 wells on which we have assumed operations during 2004. As of December 31, 2004, we operated approximately 8,800 wells, or approximately 81% of our current daily production.

- *Improve Our Balance Sheet.* We made significant progress in improving our balance sheet over the past six years. From December 31, 1998 through December 31, 2004, we have increased our shareholders' equity by $3.4 billion through a combination of earnings and common and preferred equity issuances. During 2004, we issued $650.0 million of common equity and $313.3 million of preferred equity (4.125% convertible preferred stock) and our net income was $515.2 million. We also completed an exchange of our 6.0% convertible preferred stock (liquidation preference of $224.8 million) for 24.0 million shares of common stock and forced the conversion of all of our 6.75% convertible preferred stock (liquidation preference of $149.9 million) into 19.5 million shares of common stock. As of December 31, 2004, our debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders' equity) was 49%, compared to 137% as of December 31, 1998. Additionally, through debt repurchases and exchanges completed in 2004, we have extended the average maturity of our long-term debt to over nine years and have lowered our average interest rate to 7.3%. We plan to continue improving our balance sheet in years ahead.

Based on our view that natural gas will be in a tight supply/high demand relationship in the U.S. during at least the next five years because of flat to declining supply and growing demand for this clean-burning, domestically-produced fuel, we believe our focused natural gas acquisition, exploitation and exploration strategy should provide substantial value-creating growth opportunities in the years ahead. Our goal is to increase our overall production by 10% to 20% per year, with growth at an annual rate of 10% generated organically through the drillbit and the remaining growth generated through future acquisitions. We have reached or exceeded this overall production goal in 10 of our 12 years as a public company.

Company Strengths

We believe the following six characteristics distinguish our past performance and differentiate our future growth potential from other independent natural gas producers:

- *High-Quality Asset Base.* Our producing properties are characterized by long-lived reserves, established production profiles and an emphasis on natural gas. Based upon current production and reserve estimates, our proved reserves-to-production ratio, or reserve life, is approximately 12 years. In each of our operating areas, our properties are concentrated in locations that enable us to establish substantial economies of scale in drilling and production operations and facilitate the application of more effective reservoir management practices. We intend to continue building our asset base in each of our operating areas through a balance of acquisitions, exploitation and exploration. We operate properties accounting for approximately 81% of our current daily production volumes. This large percentage of operated properties provides us with a high degree of operating flexibility and cost control.
- *Low-Cost Producer.* Our high-quality asset base, the work ethic of our employees, our "hands-on" management style and our location in Oklahoma City have enabled us to achieve a low operating and administrative cost structure. During the year ended December 31, 2004, our operating costs per unit of production were $0.95 per mcfe, which consisted of general and administrative expenses of $0.10 per mcfe (including non-cash stock-based compensation of $0.01 per mcfe), production expenses of $0.56 per mcfe and production taxes of $0.29 per mcfe. We believe this is one of the lowest cost structures among publicly traded mid- to large-cap independent oil and natural gas producers.

- *Successful Acquisition Program.* Our experienced asset acquisition team focuses on enhancing and expanding our existing assets in each of our operating areas. These areas are characterized by long-lived natural gas reserves, low lifting costs, multiple geological targets, favorable basis differentials to benchmark commodity prices, well-developed oil and gas transportation infrastructures and considerable potential for further consolidation of assets. Since 1998, we have completed $4.5 billion in acquisitions of proved properties at an average cost of $1.18 per mcfe of proved reserves (excluding $0.15 per mcfe of deferred taxes in connection with certain corporate acquisitions). We believe we are well-positioned to continue making attractive small and medium-sized acquisitions as a result of our extensive track record of identifying, completing and integrating multiple successful acquisitions, our large operating scale and our knowledge and expertise in the regions in which we operate.

- *Large Inventory of Drilling Projects.* During the 15 years since our inception, we believe we have been among the five most active drillers of new wells in the United States. Presently, we are the most active driller in the United States (with 68 operated and 62 non-operated rigs drilling) and the most active driller in the Mid-Continent (with 40 of our 68 operated rigs). Through this high level of activity over the years, we have developed an industry-leading expertise in drilling deep vertical and horizontal wells in search of large natural gas accumulations in challenging reservoir conditions. We pursue deep drilling targets because of our view that most undiscovered gas reserves in the U.S. will be found at depths below 15,000 feet. In addition, we believe that our large 3-D seismic inventory, much of which is proprietary to us, provides us with significant advantages over our competitors, which largely prefer to drill shallower development wells. As a result of our aggressive leasehold acquisition and seismic acquisition strategies, we have been able to accumulate an onshore leasehold position of approximately 3.3 million net acres and have acquired rights to over 9.9 million acres of 3-D seismic data to help evaluate our expansive acreage inventory. On this very large acreage position, our technical teams have identified over 7,000 exploratory and developmental drill sites, representing a backlog of more than seven years of future drilling opportunities.

- *Hedging Program.* We have used and intend to continue using hedging programs to reduce the risks inherent in producing oil and natural gas, commodities that are frequently characterized by significant price volatility. We believe this price volatility is likely to continue and may even increase in the years ahead, but that we can use this volatility to our benefit by taking advantage of prices when they reach levels that management believes lock in unusually high rates of return on our invested capital. Between January 1, 2001 and December 31, 2004, we have increased our oil and gas revenues by $29 million from net realized gains through our successful hedging programs. We currently have gas hedges in place covering 51% of our anticipated gas production for 2005 and 11% of our anticipated gas production for 2006 at average NYMEX prices of $6.27 and $6.38 per mcf, respectively. In addition, we have 34% of our projected oil production hedged for 2005 at an average NYMEX price of $41.02 per barrel of oil.

- *Entrepreneurial Management.* Our management team formed the company in 1989 with an initial capitalization of $50,000. Since then, our current management team has guided the company through various operational and industry challenges and extremes of oil and gas prices to create one of the four largest independent producers of natural gas in the U.S. with an enterprise value of approximately $10.1 billion (based on a common stock price of $20 per share). Our co-founders, Aubrey K. McClendon and Tom L. Ward, have been business partners in the oil and gas industry for 22 years and beneficially own, as of March 2, 2005, approximately 17.3 million and 18.8 million of our common shares, respectively.

Drilling Activity

The following table sets forth the wells we drilled during the periods indicated. In the table, "gross" refers to the total wells in which we had a working interest and "net" refers to gross wells multiplied by our working interest.

	2004				2003				2002			
	Gross	**Percent**	**Net**	**Percent**	**Gross**	**Percent**	**Net**	**Percent**	**Gross**	**Percent**	**Net**	**Percent**
Development:												
Productive	1,239	97%	462.5	98%	958	96%	401.0	97%	617	95%	237.7	95%
Non-productive	34	3	9.2	2	37	4	11.2	3	34	5	11.5	5
Total	1,273	100%	471.7	100%	995	100%	412.2	100%	651	100%	249.2	100%
Exploratory:												
Productive	164	92%	67.6	91%	76	86%	35.9	83%	47	82%	24.6	82%
Non-productive	14	8	7.0	9	12	14	7.5	17	10	18	5.4	18
Total	178	100%	74.6	100%	88	100%	43.4	100%	57	100%	30.0	100%

The following table shows the wells we drilled by area:

	2004		2003		2002	
	Gross Wells	**Net Wells**	**Gross Wells**	**Net Wells**	**Gross Wells**	**Net Wells**
Mid-Continent	1,195	417	984	403	673	263
South Texas and Texas Gulf Coast	67	38	55	25	19	9
Permian Basin	107	55	44	28	13	6
Ark-La-Tex	82	36	—	—	—	—
Other	—	—	—	—	3	1
Total	1,451	546	1,083	456	708	279

At December 31, 2004, we had 114 (50 net) wells in process. We own 10 rigs which are dedicated to drilling wells operated by Chesapeake and 12 additional rigs are under construction or on order. Our drilling business is conducted through our wholly owned subsidiary, Nomac Drilling Corporation.

Well Data

At December 31, 2004, we had interests in approximately 19,800 (8,058 net) producing wells, including properties in which we held an overriding royalty interest, of which 2,900 (1,222 net) were classified as primarily oil producing wells and 16,900 (6,836 net) were classified as primarily gas producing wells. Chesapeake operates approximately 8,800 of its 19,800 producing wells. During 2004, we drilled 561 (425 net) wells and participated in another 890 (121 net) wells operated by other companies. We operate approximately 81% of our current daily production volumes.

Production, Sales, Prices and Expenses

The following table sets forth information regarding the production volumes, oil and gas sales, average sales prices received and expenses for the periods indicated:

	2004	2003	2002
Net Production:			
Oil (mbbl)	6,764	4,665	3,466
Gas (mmcf)	322,009	240,366	160,682
Gas equivalent (mmcfe)	362,593	268,356	181,478
Oil and Gas Sales ($ in thousands):			
Oil sales	$ 260,915	$ 132,630	$ 88,495
Oil derivatives – realized gains (losses)	(69,267)	(12,058)	(1,092)
Oil derivatives – unrealized gains (losses)	3,454	(9,440)	(7,369)
Total oil sales	$ 195,102	$ 111,132	$ 80,034
Gas sales	$1,789,275	$1,171,050	$470,913
Gas derivatives – realized gains (losses)	(85,634)	(5,331)	97,138
Gas derivatives – unrealized gains (losses)	37,433	19,971	(79,898)
Total gas sales	$1,741,074	$1,185,690	$488,153
Total oil and gas sales	$1,936,176	$1,296,822	$568,187
Average Sales Price (excluding gains (losses) on derivatives):			
Oil ($ per bbl)	$ 38.57	$ 28.43	$ 25.53
Gas ($ per mcf)	$ 5.56	$ 4.87	$ 2.93
Gas equivalent ($ per mcfe)	$ 5.65	$ 4.86	$ 3.08
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Oil ($ per bbl)	$ 28.33	$ 25.85	$ 25.22
Gas ($ per mcf)	$ 5.29	$ 4.85	$ 3.54
Gas equivalent ($ per mcfe)	$ 5.23	$ 4.79	$ 3.61
Expenses ($ per mcfe):			
Production expenses	$ 0.56	$ 0.51	$ 0.54
Production taxes	$ 0.29	$ 0.29	$ 0.17
General and administrative expenses:			
General and administrative expenses (excluding stock-based compensation)	$ 0.09	$ 0.09	$ 0.10
Stock-based compensation	$ 0.01	$ 0.00	$ 0.00
Oil and gas depreciation, depletion and amortization	$ 1.61	$ 1.38	$ 1.22
Depreciation and amortization of other assets	$ 0.08	$ 0.06	$ 0.08
Interest expense(a)	$ 0.45	$ 0.55	$ 0.61

(a) Includes the effects of realized gains or (losses) from hedging, but does not include the effects of unrealized gains or (losses) from hedging.

Proved Reserves

The following table sets forth our estimated proved reserves and the present value of the proved reserves (based on our weighted average wellhead prices at December 31, 2004 of $39.91 per barrel of oil and $5.65 per mcf of gas). These weighted average wellhead prices were based on the cash spot prices for oil and natural gas at December 31, 2004.

	Oil (mbbl)	Gas (mmcf)	Gas Equivalent (mmcfe)	Percent of Proved Reserves	Present Value ($ in thousands)
Mid-Continent	46,726	3,157,081	3,437,439	70%	$ 7,112,733
South Texas and Texas Gulf Coast	2,162	377,163	390,136	8	1,067,889
Permian Basin	28,722	309,279	481,614	10	1,026,401
Ark-La-Tex	5,299	515,055	546,848	11	1,221,565
Other	5,051	15,411	45,714	1	75,802
Total	87,960	4,373,989	4,901,751	100%	$10,504,390[(a)]

(a) The standardized measure of discounted future net cash flows at December 31, 2004 was $7.6 billion.

As of December 31, 2004, the present value of our proved developed reserves as a percentage of total proved reserves was 70%, and the volume of our proved developed reserves as a percentage of total proved reserves was 66%. Natural gas reserves accounted for 89% of the volume of total proved reserves at December 31, 2004.

Future prices and costs may be materially higher or lower than the prices and costs as of the date of any estimate. A change in price of $0.10 per mcf for natural gas and $1.00 per barrel for oil would result in a change in our December 31, 2004 present value of proved reserves of approximately $215 million and $40 million, respectively.

Development, Exploration, Acquisition and Divestiture Activities

The following table sets forth historical cost information regarding our development, exploration, acquisition and divestiture activities during the periods indicated:

	Years Ended December 31, 2004	2003	2002
	($ in thousands)		
Acquisition of properties:			
Proved properties	$1,541,920	$1,110,077	$316,583
Unproved properties	570,495	198,394	14,000
Deferred income taxes	463,949	(4,903)	62,398
Development costs:			
Development drilling (a)	863,268	474,355	240,313
Leasehold acquisition costs	110,530	84,984	44,734
Asset retirement obligation and other (c)	41,924	54,657	2,541
Exploration costs:			
Exploratory drilling	128,635	103,424	89,422
Geological and geophysical costs (b)	55,618	42,736	25,819
Sales of oil and gas properties	(12,048)	(22,156)	(839)
Total	$3,764,291	$2,041,568	$794,971

(a) Includes capitalized internal cost of $45.4 million, $30.9 million and $21.3 million, respectively.
(b) Includes capitalized internal cost of $6.3 million, $4.6 million and $3.0 million, respectively.
(c) The 2003 amount includes $24.1 million of asset retirement costs recorded as a result of implementation of SFAS 143 effective January 1, 2003.

Our development and leasehold costs included $333 million, $229 million and $120 million of expenditures in 2004, 2003 and 2002, respectively, related to properties carried as proved undeveloped locations in the prior year's reserve reports. Included in our reserve report as of December 31, 2004 are estimated future development costs of $1.9 billion related to the development of proved undeveloped reserves ($1.0 billion in 2005, $0.5 billion in 2006, $0.2 billion in 2007 and $0.2 billion in 2008 and beyond). Chesapeake's developmental drilling schedules are subject to revision and reprioritization throughout the year, resulting from unknowable factors such as the relative success in an individual developmental drilling prospect leading to an additional drilling opportunity, rig availability, title issues or delays, and the effect that acquisitions may have on prioritizing development drilling plans.

Acreage

The following table sets forth as of December 31, 2004 the gross and net acres of both developed and undeveloped oil and gas leases which we hold. "Gross" acres are the total number of acres in which we own a working interest. "Net" acres refer to gross acres multiplied by our fractional working interest. Acreage numbers do not include our options to acquire additional leasehold which have not been exercised.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	3,285,276	1,653,500	1,686,037	815,715	4,971,313	2,469,215
South Texas and Texas Gulf Coast	317,828	204,727	259,517	164,531	577,345	369,258
Permian Basin	111,546	62,862	527,877	249,030	639,423	311,892
Ark-La-Tex	40,449	21,843	109,486	60,237	149,935	82,080
Other	41,930	18,587	118,142	91,504	160,072	110,091
Total	3,797,029	1,961,519	2,701,059	1,381,017	6,498,088	3,342,536

Marketing

Chesapeake's oil production is generally sold under market sensitive or spot price contracts. Our natural gas production is sold to purchasers under percentage-of-proceeds contracts, percentage-of-index contracts or spot price contracts. By the terms of the percentage-of-proceeds contracts, we receive a percentage of the resale price received by the purchaser for sales of residue gas and natural gas liquids recovered after transportation and processing of our gas. These purchasers sell the residue gas and natural gas liquids based primarily on spot market prices. The revenue we receive from the sale of natural gas liquids is included in oil sales. Under percentage-of-index contracts, the price per mmbtu we receive for our gas is tied to indexes published in *Inside FERC* or *Gas Daily*.

During 2004, sales to Eagle Energy Partners I, L.P. ("Eagle") of $467 million accounted for 17% of our total revenues. Chesapeake owns approximately 31% of Eagle. Management believes that the loss of this customer would not have a material adverse effect on our results of operations or our financial position. No other customer accounted for more than 10% of total revenues in 2004.

Chesapeake Energy Marketing, Inc., which is our marketing subsidiary, provides marketing services, including commodity price structuring, contract administration and nomination services for Chesapeake and its partners. This subsidiary is a reportable segment under SFAS No. 131, *Disclosure about Segments of an Enterprise and Related Information.* See note 8 of notes to consolidated financial statements in Item 8.

Hedging Activities

We utilize hedging strategies to hedge the price of a portion of our future oil and natural gas production and to manage interest rate exposure. See Item 7A—Quantitative and Qualitative Disclosures About Market Risk.

Risk Factors

Oil and gas prices are volatile. A decline in prices could adversely affect our financial position, financial results, cash flows, access to capital and ability to grow.

Our revenues, operating results, profitability and future rate of growth depend primarily upon the prices we receive for the oil and gas we sell. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. The amount we can borrow from banks is subject to periodic redeterminations based on prices specified by our bank group at the time of redetermination. In addition, we may have ceiling test write-downs in the future if prices fall significantly.

Historically, the markets for oil and gas have been volatile and they are likely to continue to be volatile. Wide fluctuations in oil and gas prices may result from relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and other factors that are beyond our control, including:

- worldwide and domestic supplies of oil and gas,
- weather conditions,
- the level of consumer demand,
- the price and availability of alternative fuels,
- the availability of pipeline capacity,
- the price and level of foreign imports,
- domestic and foreign governmental regulations and taxes,
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls,
- political instability or armed conflict in oil-producing regions, and
- the overall economic environment.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and gas price movements with any certainty. Declines in oil and gas prices would not only reduce revenue, but could reduce the amount of oil and gas that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves. Further, oil and gas prices do not necessarily move in tandem. Because approximately 89% of our reserves at December 31, 2004 are natural gas reserves, we are more affected by movements in natural gas prices.

Our level of indebtedness may limit our financial flexibility.

As of December 31, 2004, we had long-term indebtedness of $3.1 billion, with $59 million drawn under our revolving bank credit facility. Our long-term indebtedness represented 49% of our total book capitalization at December 31, 2004. We increased the borrowing base under our revolving bank credit facility to $1.25 billion on January 28, 2005, with approximately $437 million drawn as of March 2, 2005.

Our level of indebtedness affects our operations in several ways, including the following:

- a portion of our cash flows from operating activities must be used to service our indebtedness and is not available for other purposes,
- we may be at a competitive disadvantage as compared to similar companies that have less debt,
- the covenants contained in the agreements governing our outstanding indebtedness and future indebtedness may limit our ability to borrow additional funds, pay dividends and make certain investments and may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry,

- additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes may have higher costs and more restrictive covenants,
- changes in the credit ratings of our debt may negatively affect the cost, terms, conditions and availability of future financing, and lower ratings will increase the interest rate and fees we pay on our revolving bank credit facility, and
- we may be more vulnerable to general adverse economic and industry conditions.

We may incur additional debt, including significant secured indebtedness, in order to make future acquisitions or to develop our properties. A higher level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, oil and gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flow to pay the interest on our debt, and future working capital, borrowings or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital.

In addition, our bank borrowing base is subject to periodic redetermination. A lowering of our borrowing base could require us to repay indebtedness in excess of the borrowing base, or we might need to further secure the lenders with additional collateral.

Competition in the oil and natural gas industry is intense, and many of our competitors have greater financial and other resources than we do.

We operate in the highly competitive areas of oil and natural gas acquisition, development, exploitation, exploration and production. We face intense competition from both major and other independent oil and natural gas companies in each of the following areas:

- seeking to acquire desirable producing properties or new leases for future exploration, and
- seeking to acquire the equipment and expertise necessary to develop and operate our properties.

Many of our competitors have financial and other resources substantially greater than ours, and some of them are fully integrated oil companies. These companies may be able to pay more for development prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to develop and exploit our oil and natural gas properties and to acquire additional properties in the future will depend upon our ability to successfully conduct operations, evaluate and select suitable properties and consummate transactions in this highly competitive environment.

Significant capital expenditures are required to replace our reserves.

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations, our revolving bank credit facility and debt and equity issuances. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of oil and gas, and our success in developing and producing new reserves. If revenue were to decrease as a result of lower oil and gas prices or decreased production, and our access to capital were limited, we would have a reduced ability to replace our reserves. If our cash flow from operations is not sufficient to meet our obligations and fund our capital expenditure budget, we may not be able to access debt, equity or other methods of financing on an economic basis to meet these requirements.

If we are not able to replace reserves, we may not be able to sustain production.

Our future success depends largely upon our ability to find, develop or acquire additional oil and gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, exploration or acquisition activities, our proved reserves and production will decline over time. In addition, approximately 34% of our total estimated proved reserves (by volume) at December 31, 2004 were undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. Our reserve estimates reflect that our production rate on producing properties will decline approximately 26% from the beginning until the end of 2005. Thus, our future oil and natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves.

The actual quantities and present value of our proved reserves may prove to be lower than we have estimated.

This report contains estimates of our proved reserves and the estimated future net revenues from our proved reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and gas reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from these estimates. Such variations may be significant and could materially affect the estimated quantities and present value of our proved reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development drilling, prevailing oil and gas prices and other factors, many of which are beyond our control. Our properties may also be susceptible to hydrocarbon drainage from production by operators on adjacent properties.

At December 31, 2004, approximately 34% of our estimated proved reserves (by volume) were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. These reserve estimates include the assumption that we will make significant capital expenditures to develop these reserves, including $1.0 billion in 2005. You should be aware that the estimated costs may not be accurate, development may not occur as scheduled and results may not be as estimated.

You should not assume that the present values referred to in this report represent the current market value of our estimated oil and gas reserves. In accordance with SEC requirements, the estimates of our present values are based on prices and costs as of the date of the estimates. The December 31, 2004 present value is based on weighted average oil and gas wellhead prices of $39.91 per barrel of oil and $5.65 per mcf of natural gas. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of an estimate.

Any changes in consumption by oil and gas purchasers or in governmental regulations or taxation will also affect actual future net cash flows.

The timing of both the production and the expenses from the development and production of oil and gas properties will affect both the timing of actual future net cash flows from our proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and gas industry in general will affect the accuracy of the 10% discount factor.

Acquisitions may prove to be worth less than we paid because of uncertainties in evaluating recoverable reserves and potential liabilities.

Our recent growth is due in part to acquisitions of exploration and production companies, producing properties and undeveloped leasehold. We expect acquisitions will also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, exploration potential, future oil and gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. We are generally not entitled to contractual indemnification for preclosing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. As a result of these factors, we may not be able to acquire oil and gas properties that contain economically recoverable reserves or be able to complete such acquisitions on acceptable terms.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or be in different geographic locations than our existing properties. It is our current intention to continue focusing on acquiring properties with development and exploration potential located in the Mid-Continent, the South Texas and Texas Gulf Coast region, the Permian Basin region and the Ark-La-Tex area. To the extent that we acquire properties substantially different from the properties in our operating regions or acquire properties that require different technical expertise, we may not be able to realize the economic benefits of these acquisitions as efficiently as in our prior acquisitions.

Exploration and development drilling may not result in commercially productive reserves.

We do not always encounter commercially productive reservoirs through our drilling operations. The new wells we drill or participate in may not be productive and we may not recover all or any portion of our investment in wells we drill or participate in. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or gas is present or may be produced economically. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Our efforts will be unprofitable if we drill dry wells or wells that are productive but do not produce enough reserves to return a profit after drilling, operating and other costs. Further, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions,
- title problems,
- pressure or irregularities in formations,
- equipment failures or accidents,
- adverse weather conditions,
- compliance with environmental and other governmental requirements, and
- increases in the cost of, or shortages or delays in the availability of, drilling rigs and equipment.

Future price declines may result in a write-down of our asset carrying values.

We utilize the full cost method of accounting for costs related to our oil and gas properties. Under this method, all such costs (for both productive and nonproductive properties) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the unit-of-production method. However, these capitalized costs are subject to a ceiling test which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved oil and gas reserves discounted at 10% plus the lower of cost or market value of unproved properties. The full cost ceiling is evaluated at the end of each quarter using the prices for oil and gas at that date, adjusted for the impact of derivatives accounted for as cash flow hedges. A significant decline in oil and gas prices from current levels, or other factors, without other mitigating circumstances, could cause a future writedown of capitalized costs and a non-cash charge against future earnings. Our aggregate present value of future net revenues plus the value of the unproved properties would equal the recorded net book value of our oil and gas properties at December 31, 2004, assuming an index price of approximately $3.90 per mcf for gas and assuming the price of oil remains constant at $43.39 per barrel for oil. If index prices were to fall below these levels, we could experience a write-down of the book value of our oil and gas assets.

Our hedging activities may reduce the realized prices received for our oil and gas sales and require us to provide collateral for hedging liabilities.

In order to manage our exposure to price volatility in marketing our oil and gas, we enter into oil and gas price risk management arrangements for a portion of our expected production. Commodity price hedging may limit the prices we actually realize and therefore reduce oil and gas revenues in the future. The fair value of our oil and gas derivative instruments outstanding as of December 31, 2004 was an asset of approximately $38.4 million. In addition, our commodity price risk management transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected,
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement, or
- the counterparties to our contracts fail to perform under the contracts.

Some of our commodity price risk management arrangements require us to deliver cash collateral or other assurances of performance to the counterparties in the event that our payment obligations exceed certain levels. As of December 31, 2004, we were required to post a total of $66 million of collateral with our counterparties through letters of credit issued under our bank credit facility with respect to commodity price and financial risk management transactions. As of March 2, 2005, we were required to post a total of $61 million of collateral. Future collateral requirements are uncertain and will depend on arrangements with our counterparties, highly volatile natural gas and oil prices.

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

Our amended and restated revolving bank credit facility limits our borrowings to $1.25 billion, based on our borrowing base. The borrowing base is determined periodically at the discretion of a majority of the banks and is based in part on oil and gas prices. Additionally, some of our indentures contain covenants limiting our ability to incur indebtedness in addition to that incurred under our bank credit facility. These indentures limit our ability to incur additional indebtedness unless we meet one of two alternative tests. The first alternative is based on our adjusted consolidated net tangible assets (as defined in all of our indentures), which is determined using discounted future net revenues from proved oil and gas reserves as of the end of each year. The second alternative is based on the ratio of our adjusted consolidated EBITDA (as defined in all of our indentures) to our adjusted consolidated interest expense over a trailing twelve-month period. As of December 31, 2004 we were permitted to incur significant additional indebtedness under both of these debt incurrence tests. Lower oil and gas prices in the future could reduce our adjusted consolidated EBITDA, as well as our adjusted consolidated net tangible assets, and thus could reduce our ability to incur additional indebtedness.

Oil and gas drilling and producing operations can be hazardous and may expose us to environmental liabilities.

Oil and gas operations are subject to many risks, including well blowouts, cratering and explosions, pipe failure, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, and other environmental hazards and risks. Our drilling operations involve risks from high pressures and from mechanical difficulties such as stuck pipes, collapsed casings and separated cables. If any of these risks occur, we could sustain substantial losses as a result of:

- injury or loss of life,
- severe damage to or destruction of property, natural resources and equipment,
- pollution or other environmental damage,
- clean-up responsibilities,
- regulatory investigations and penalties, and
- suspension of operations.

Our liability for environmental hazards includes those created either by the previous owners of properties that we purchase or lease or by acquired companies prior to the date we acquire them. We maintain insurance against some, but not all, of the risks described above. Our insurance may not be adequate to cover casualty losses or liabilities. Also, in the future we may not be able to obtain insurance at premium levels that justify its purchase.

Regulation

General. The oil and gas industry is subject to regulation at the federal, state and local level, and some of the laws, rules and regulations that govern our operations carry substantial penalties for noncompliance. This regulatory burden increases our cost of doing business and, consequently, affects our profitability.

Exploration and Production. Our operations are subject to various types of regulation at the U.S. federal, state and local levels. Such regulation includes requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling and well operations. Other activities subject to regulation are:

- the location of wells,
- the method of drilling and completing wells,
- the surface use and restoration of properties upon which wells are drilled,
- the plugging and abandoning of wells,
- the disposal of fluids used or other wastes obtained in connection with operations,
- the marketing, transportation and reporting of production, and
- the valuation and payment of royalties.

Our operations are also subject to various conservation regulations. These include the regulation of the size of drilling and spacing units (regarding the density of wells which may be drilled in a particular area) and the unitization or pooling of oil and gas properties. In this regard, some states, such as Oklahoma, allow the forced pooling or integration of tracts to facilitate exploration, while other states, such as Texas, rely on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units and, therefore, more difficult to fully develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose certain requirements regarding the ratability of production. The effect of these regulations is to limit the amount of oil and gas we can produce and to limit the number of wells or the locations at which we can drill.

We do not anticipate that compliance with existing laws and regulations governing exploration and production will have a significantly adverse effect upon our capital expenditures, earnings or competitive position.

Environmental Regulation. Various federal, state and local laws and regulations concerning the discharge of contaminants into the environment, the generation, storage, transportation and disposal of contaminants, and the protection of public health, natural resources, wildlife and the environment affect our exploration, development and production operations, including processing facilities. We must take into account the cost of complying with environmental regulations in planning, designing, drilling, operating and abandoning wells. In most instances, the regulatory requirements relate to the handling and disposal of drilling and production waste products, water and air pollution control procedures, and the remediation of petroleum-product contamination. In addition, our operations may require us to obtain permits for, among other things,

- air emissions,
- discharges into surface waters, and
- the construction and operation of underground injection wells or surface pits to dispose of produced saltwater and other nonhazardous oilfield wastes.

Under state and federal laws, we could be required to remove or remediate previously disposed wastes, including wastes disposed of or released by us or prior owners or operators in accordance with current laws or otherwise, to suspend or cease operations in contaminated areas, or to perform remedial well plugging operations or cleanups to prevent future contamination. The Environmental Protection Agency and various state agencies have limited the disposal options for hazardous and nonhazardous wastes. The owner and operator of a site, and persons that treated, disposed of or arranged for the disposal of hazardous substances found at a site, may be liable, without regard to fault or the legality of the original conduct, for the release of a hazardous substance into the environment. The Environmental Protection Agency, state environmental agencies and, in some cases, third parties are authorized to take actions in response to threats to human health or the environment and to seek to recover from responsible classes of persons the costs of such action. Furthermore, certain wastes generated by our oil and natural gas operations that are currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes and, therefore, be subject to considerably more rigorous and costly operating and disposal requirements.

Federal and state occupational safety and health laws require us to organize information about hazardous materials used, released or produced in our operations. Certain portions of this information must be provided to employees, state and local governmental authorities and local citizens. We are also subject to the requirements and reporting set forth in federal workplace standards.

We have made and will continue to make expenditures to comply with environmental regulations and requirements. These are necessary business costs in the oil and gas industry. Although we are not fully insured against all environmental risks, we maintain insurance coverage which we believe is customary in the industry. Moreover, it is possible that other developments, such as stricter and more comprehensive environmental laws and regulations, as well as claims for damages to property or persons resulting from company operations, could result in substantial costs and liabilities, including civil and criminal penalties, to Chesapeake. We believe we are in compliance with existing environmental regulations, and that, absent the occurrence of an extraordinary event the effect of which cannot be predicted, any noncompliance will not have a material adverse effect on our operations or earnings.

Income Taxes

Chesapeake recorded income tax expense of $289.8 million in 2004 compared to income tax expense of $191.8 million in 2003 and $26.9 million in 2002. Our effective income tax rate decreased to 36% in 2004 compared to 38% in 2003 and 40% in 2002. The decrease in 2004 and 2003 reflected the impact state income taxes had on our overall effective rate. Our effective income tax rate will increase to 36.5% in 2005 to reflect our current assessment of the impact state income taxes and permanent differences will have on our overall effective income tax rate.

At December 31, 2004, Chesapeake had federal income tax net operating loss (NOL) carryforwards of approximately $546 million. We also had approximately $114 million of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income and approximately $10 million of percentage depletion carryforwards. The NOL carryforwards expire from 2012 through 2024. The value of the remaining carryforwards depends on the ability of Chesapeake to generate taxable income. In addition, for AMT purposes, only 90% of AMT income in any given year may be offset by AMT NOLs.

The ability of Chesapeake to utilize NOL carryforwards to reduce future federal taxable income and federal income tax is subject to various limitations under the Internal Revenue Code of 1986, as amended. The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the issuance or exercise of rights to acquire stock, the purchase or sale of stock by 5% stockholders, as defined in the Treasury regulations, and the offering of stock by us during any three-year period resulting in an aggregate change of more than 50% in the beneficial ownership of Chesapeake.

In the event of an ownership change (as defined for income tax purposes), Section 382 of the Code imposes an annual limitation on the amount of a corporation's taxable income that can be offset by these carryforwards. The limitation is generally equal to the product of (i) the fair market value of the equity of the company multiplied by (ii) a percentage approximately equivalent to the yield on long-term tax exempt bonds during the month in which an ownership change occurs. In addition, the limitation is increased if there are recognized built-in gains during any post-change year, but only to the extent of any net unrealized built-in gains (as defined in the Code) inherent in the assets sold. Certain NOLs acquired through various acquisitions are also subject to limitations. The following table summarizes our net operating losses as of December 31, 2004 and any related limitations:

	Net Operating Losses		
	Total	Limited	Annual Limitation
		($ in thousands)	
Net operating loss	$545,848	$118,089	$50,030
AMT net operating loss	$114,021	$ 38,479	$18,045

Although no assurances can be made, we do not believe that an ownership change has occurred as of December 31, 2004. Future equity transactions by Chesapeake or by 5% stockholders (including relatively small transactions and transactions beyond our control) could cause an ownership change and therefore a limitation on the annual utilization of NOLs.

In the event of an ownership change, the amount of Chesapeake's NOLs available for use each year will depend upon future events that cannot currently be predicted and upon interpretation of complex rules under Treasury regulations. If less than the full amount of the annual limitation is utilized in any given year, the unused portion may be carried forward and may be used in addition to successive years' annual limitation.

We expect to utilize our NOL carryforwards and other tax deductions and credits to offset taxable income in the future. However, there is no assurance that the Internal Revenue Service will not challenge these carryforwards or their utilization.

In 2002, the Internal Revenue Service completed an audit of Chesapeake for the years ended December 31, 1999 and 2000. There were no significant adjustments resulting from this audit.

Title to Properties

Our title to properties is subject to royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the oil and gas industry, to liens for current taxes not yet due and to other encumbrances. As is customary in the industry in the case of undeveloped properties, only cursory investigation of record title is made at the time of acquisition. Drilling title opinions are usually prepared before commencement of drilling operations. We believe we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the oil and gas industry. Nevertheless, we are involved in title disputes from time to time which result in litigation.

Operating Hazards and Insurance

The oil and gas business involves a variety of operating risks, including the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards such as oil spills, gas leaks, ruptures or discharges of toxic gases. If any of these should occur, Chesapeake could suffer substantial losses due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, and suspension of operations. Our horizontal and deep drilling activities involve greater risk of mechanical problems than vertical and shallow drilling operations.

Chesapeake maintains a $50 million oil and gas lease operator policy that insures against certain sudden and accidental risks associated with drilling, completing and operating our wells. There is no assurance that this insurance will be adequate to cover all losses or exposure to liability. Chesapeake also carries a $125 million comprehensive general liability umbrella policy and a $75 million pollution liability policy. We provide workers' compensation insurance coverage to employees in all states in which we operate and we maintain a $1 million employment practice liability policy. While we believe these policies are customary in the industry, they do not provide complete coverage against all operating risks.

Employees

Chesapeake had 1,718 employees as of December 31, 2004, which includes 209 employed by our drilling subsidiary, Nomac Drilling Corporation. No employees are represented by organized labor unions. We believe our employee relations are good.

Glossary of Oil and Gas Terms

The terms defined in this section are used throughout this Form 10-K.

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet of gas equivalent.

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

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.

Commercial Well; Commercially Productive Well. An oil and gas well which produces oil and gas in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Developed Acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development 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; Dry Well. A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Exploratory Well. A well drilled to find and produce oil or gas in an unproved area, 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.

Farmout. An assignment of an interest in a drilling location and related acreage conditional upon the drilling of a well on that location.

Formation. A succession of sedimentary beds that were deposited under the same general geologic conditions.

Full Cost Pool. The full cost pool consists of all costs associated with property acquisition, exploration, and development activities for a company using the full cost method of accounting. Additionally, any internal costs that can be directly identified with acquisition, exploration and development activities are included. Any costs related to production, general corporate overhead or similar activities are not included.

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

Horizontal Wells. Wells which are drilled at angles greater than 70 degrees from vertical.

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

Mbtu. One thousand btus.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet of gas equivalent.

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

Mmbtu. One million btus.

Mmcf. One million cubic feet.

Mmcfe. One million cubic feet of gas equivalent.

Net Acres or Net Wells. The sum of the fractional working interests owned in gross acres or gross wells.

NYMEX. New York Mercantile Exchange.

Present Value or PV-10. When used with respect to oil and gas reserves, present value or PV-10 means 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 at the determination date, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

Productive Well. A well that is producing oil or gas or that is capable of production.

Proved Developed Reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production responses that increased recovery will be achieved.

Reserve Replacement. Calculated by dividing the sum of reserve additions from all sources (revisions, extensions and acquisitions) by the actual production for the corresponding period. The values for these reserve additions are derived directly from the proved reserves table on page 94. Management uses the reserve replacement ratio as an indicator of the Company's ability to replenish annual production volumes and grow its reserves, thereby providing some information on the sources of future production.

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, i.e., prices and costs as of the date the estimate is made. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

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. Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Proved undeveloped reserves may not include estimates attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

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

Standardized Measure of Discounted Future Net Cash Flows. The discounted future net cash flows relating to proved reserves based on year-end prices, costs and statutory tax rates (adjusted for permanent differences) and a 10-percent annual discount rate.

Tcf. One trillion cubic feet.

Tcfe. One trillion cubic feet of gas equivalent.

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

ITEM 2. ***Properties***

Chesapeake focuses its natural gas exploration, development and acquisition efforts in one primary operating area and in three secondary operating areas: (i) the Mid-Continent (consisting of Oklahoma, western Arkansas, southwestern Kansas and the Texas Panhandle), representing 70% of our proved reserves, (ii) the South Texas and Texas Gulf Coast region, representing 8% of our proved reserves, (iii) the Permian Basin of western Texas and eastern New Mexico, representing 10% of our proved reserves, and (iv) the Ark-La-Tex area of central and eastern Texas and northern Louisiana, representing 11% of our proved reserves.

During the year ended December 31, 2004, we participated in 1,451 gross (546 net) wells, 561 (425 net) of which we operated. A summary of our development, exploration, acquisition and divestiture activities by operating area is as follows:

	Gross Wells Drilled	Net Wells Drilled	Exploration and Development	Leasehold	Acquisition of Unproved Properties	Acquisition of Proved Properties (a)	Sales of Properties	Total
					($ in thousands)			
Mid-Continent	1,195	417	$ 800,072	$ 78,935	$165,992	$ 537,329	$(12,048)	$1,570,280
South Texas and Texas Gulf Coast	67	38	113,922	11,109	148,267	202,516	—	475,814
Permian Basin	107	55	98,854	18,879	90,650	597,372	—	805,755
Ark-La-Tex	82	36	73,632	1,328	161,962	665,404	—	902,326
Other	—	—	2,965	279	3,624	3,248	—	10,116
Total	1,451	546	$1,089,445	$110,530	$570,495	$2,005,869	$(12,048)	$3,764,291

(a) Includes $463.9 million of deferred tax adjustments.

Chesapeake's proved reserves increased 55% during 2004 to an estimated 4,902 bcfe at December 31, 2004, compared to 3,169 bcfe of estimated proved reserves at December 31, 2003. See note 11 of notes to our consolidated financial statements in Item 8 of this report.

Chesapeake's strategy for 2005 is to continue developing our natural gas assets through exploratory and developmental drilling and by selectively acquiring strategic properties in the Mid-Continent and in our secondary areas. We project that our 2005 production will be between 430 bcfe and 438 bcfe. We have budgeted $1.4 to $1.5 billion for drilling, acreage acquisition, seismic and related capitalized internal costs, all of which is expected to be funded with operating cash flow based on our current assumptions. Our budget is frequently adjusted based on changes in oil and gas prices, drilling results, drilling costs and other factors. We expect to fund future acquisitions through a combination of operating cash flow, our revolving bank credit facility and new debt and equity issuances.

Primary Operating Area

Mid-Continent. Chesapeake's Mid-Continent proved reserves of 3,437 bcfe represented 70% of our total proved reserves as of December 31, 2004, and this area produced 268.5 bcfe, or 74%, of our 2004 production. We anticipate the Mid-Continent will contribute approximately 292 bcfe, or 67%, of expected total production during 2005. During 2004, we invested approximately $800.1 million to drill 1,195 (417 net) wells in the Mid-Continent. We anticipate spending approximately 58% of our total budget for exploration and development activities in the Mid-Continent region during 2005.

Secondary Operating Areas

South Texas and Texas Gulf Coast. Chesapeake's South Texas and Texas Gulf Coast proved reserves represented 390 bcfe, or 8%, of our total proved reserves as of December 31, 2004. During 2004, the South

Texas and Texas Gulf Coast assets produced 42.4 bcfe, or 12%, of our total production. We anticipate this area will contribute approximately 58 bcfe, or 13%, of expected total production during 2005. During 2004, we invested approximately $113.9 million to drill 67 (38 net) wells in the South Texas and Texas Gulf Coast region. We anticipate spending approximately 13% of our total budget for exploration and development activities in the South Texas and Texas Gulf Coast region during 2005.

Permian Basin. Chesapeake's Permian Basin proved reserves represented 482 bcfe, or 10%, of our total proved reserves as of December 31, 2004. During 2004, the Permian assets produced 29.5 bcfe, or 8%, of our total production. We anticipate the Permian Basin will contribute approximately 34 bcfe, or 8%, of expected total production during 2005. During 2004, we invested approximately $98.9 million to drill 107 (55 net) wells in the Permian Basin. For 2005, we anticipate spending approximately 13% of our total budget for exploration and development activities in the Permian Basin.

Ark-La-Tex. Chesapeake's Ark-La-Tex proved reserves represented 547 bcfe, or 11%, of our total proved reserves as of December 31, 2004. During 2004, the Ark-La-Tex assets produced 19.6 bcfe, or 5%, of our total production. We anticipate the Ark-La-Tex will contribute approximately 48 bcfe, or 11%, of expected total production during 2005. During 2004, we invested approximately $73.6 million to drill 82 (36 net) wells in Ark-La-Tex. For 2005, we anticipate spending approximately 16% of our total budget for exploration and development activities in Ark-La-Tex.

Oil and Gas Reserves

The tables below set forth information as of December 31, 2004 with respect to our estimated proved reserves, the associated estimated future net revenue and the present value at such date. Chesapeake employed third party engineers to prepare independent reserve forecasts for approximately 75% of our proved reserves (by volume) and 76% (by value) at year-end 2004. These are not audits or reviews of internally prepared reserve reports. The company's own estimates of the proved reserves evaluated by third party engineers were within 99% of the third party estimates. Netherland, Sewell & Associates, Inc. evaluated 25%, Lee Keeling and Associates, Inc. evaluated 23%, Ryder Scott Company L.P. evaluated 12%, LaRoche Petroleum Consultants, Ltd. evaluated 7%, H. J. Gruy and Associates, Inc. evaluated 7% and Miller and Lents, Ltd. evaluated 2% of our estimated proved reserves at December 31, 2004 based on discounted future net revenues. Of the 25,264 properties included in the 2004 report, the reserve estimates prepared by the independent firms covered 8,761 properties, or 34.7% of the total well count. Because of the time, effort and cost involved in preparing reserve estimates on every oil and gas property owned by Chesapeake, the company's internal reservoir engineers evaluated many of the properties, but these represent only 24% of our proved reserves. All estimates were prepared based upon a review of production histories and other geologic, economic, ownership and engineering data we developed. The estimates are not based on any single significant assumption due to the diverse nature of the reserves and there is no significant concentration of proved reserves volume or value in any one well. The present value of estimated future net revenue shown is not intended to represent the current market value of the estimated oil and gas reserves we own.

Estimated Proved Reserves as of December 31, 2004	**Oil (mbbl)**	**Gas (mmcf)**	**Total (mmcfe)**
Proved developed	62,713	2,842,141	3,218,418
Proved undeveloped	25,247	1,531,848	1,683,333
Total proved	87,960	4,373,989	4,901,751

Estimated Future New Revenue as of December 31, 2004	**Proved Developed**	**Proved Undeveloped**	**Total Proved**
		($ in thousands)	
Estimated future net revenue (a)	$13,323,584	$6,260,774	$19,584,358
Present value of future net revenue	$ 7,366,167	$3,138,223	$10,504,390[b]

(a) Estimated future net revenue represents 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 at December 31, 2004. The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization. The prices used in the external and internal reports yield weighted average wellhead prices of $39.91 per barrel of oil and $5.65 per mcf of gas. These prices should not be interpreted as a prediction of future prices.

(b) The standardized measure of discounted future net cash flows at December 31, 2004 was $7.6 billion.

As of December 31, 2004, our reserve estimates included 1,683.3 bcfe of reserves classified as proved undeveloped (PUD). Of this amount, approximately 68% (by volume) were initially classified as PUDs in 2004, 11% were initially classified as PUDs in 2003, 6% were initially classified as PUDs in 2002, and the remaining 15% were initially classified as PUDs prior to 2002. Of our proved developed reserves, 413 bcfe are non-producing, which are primarily "behind pipe" zones in producing wells.

The future net revenue attributable to our estimated proved undeveloped reserves of $6.3 billion at December 31, 2004, and the $3.1 billion present value thereof, has been calculated assuming that we will expend approximately $1.9 billion to develop these reserves. The amount and timing of these expenditures will depend on a number of factors, including actual drilling results, product prices and the availability of capital, but we have projected to incur $1.0 billion in 2005, $0.5 billion in 2006, $0.2 billion in 2007 and $0.2 billion in 2008 and beyond. We do not believe any of these proved undeveloped reserves are contingent upon installation of additional infrastructure and we are not subject to regulatory approval other than routine permits to drill, which we expect to obtain in the normal course of business.

No estimates of proved reserves comparable to those included herein have been included in reports to any federal agency other than the Securities and Exchange Commission.

Chesapeake's ownership interest used in calculating proved reserves and the associated estimated future net revenue was determined after giving effect to the assumed maximum participation by other parties to our farmout and participation agreements. The prices used in calculating the estimated future net revenue attributable to proved reserves do not reflect market prices for oil and gas production sold subsequent to December 31, 2004. There can be no assurance that all of the estimated proved reserves will be produced and sold at the assumed prices.

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 Chesapeake's control. The reserve data represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way, and 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 made by different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimates, and such revisions may be material. Accordingly, reserve estimates are often different from the actual quantities of oil and gas that are ultimately recovered. Furthermore, the estimated future net revenue from proved reserves and the associated present value are based upon certain assumptions, including prices, future production levels and costs that may not prove correct. The foregoing uncertainties are particularly true as to proved undeveloped reserves, which are inherently less certain than proved developed reserves and which comprise a significant portion of our proved reserves. In addition, the estimated future net revenue from proved reserves and the associated present value do not include any estimates of corporate overhead, debt service costs, future income tax expense, or depreciation, depletion and amortization expense.

See Item 1— Business and note 11 of notes to consolidated financial statements included in Item 8 of this report for a description of drilling, production and other information regarding our oil and gas properties.

Facilities

Chesapeake owns an office complex in Oklahoma City and also owns field offices in Arkoma, Lindsay, Waynoka, Weatherford and Wilburton, Oklahoma; Garden City, Kansas; Borger, Dumas and College Station, Texas; Van Buren, Arkansas; Cheneyville, Louisiana; and Eunice and Hobbs, New Mexico. In addition, Chesapeake leases office space in Oklahoma City, Forgan, Kingfisher and Sayre, Oklahoma; Zapata, Texas; Dickinson, North Dakota and Shreveport, Louisiana. Chesapeake owns approximately 55 gas gathering and processing facilities located in Oklahoma, Kansas, Texas and Louisiana.

ITEM 3. *Legal Proceedings*

We are currently involved in various disputes incidental to our business operations. We believe that the final resolution of currently pending or threatened litigation is not likely to have a material adverse effect on our financial position or results of operations.

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

Not applicable.

PART II

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

Price Range of Common Stock

Our common stock trades on the New York Stock Exchange under the symbol "CHK." The following table sets forth, for the periods indicated, the high and low sales prices per share of our common stock as reported by the New York Stock Exchange:

	Common Stock	
	High	**Low**
Year ended December 31, 2003:		
First Quarter	$ 8.64	$ 7.27
Second Quarter	11.45	7.45
Third Quarter	10.97	9.17
Fourth Quarter	14.00	10.66
Year ended December 31, 2004:		
First Quarter	$13.98	$11.70
Second Quarter	15.05	12.68
Third Quarter	16.24	13.69
Fourth Quarter	18.31	15.17

At March 2, 2005 there were 1,265 holders of record of our common stock and approximately 140,000 beneficial owners.

Dividends

The following table sets forth the amount of dividends per share declared on Chesapeake common stock during the two years ended December 31:

	2004	2003
First Quarter	$0.035	$0.030
Second Quarter	0.045	0.035
Third Quarter	0.045	0.035
Fourth Quarter	0.045	0.035

While we expect to continue to pay dividends on our common stock, the payment of future cash dividends will depend upon, among other things, our financial condition, funds from operations, the level of our capital and development expenditures, our future business prospects, contractual restrictions and any other factors considered relevant by the board of directors.

The indentures governing our outstanding senior notes contain restrictions on our ability to declare and pay cash dividends. Under these indentures, we may not pay any cash dividends on our common or preferred stock if an event of default has occurred, if we have not met one of the two debt incurrence tests described in the indentures, or if immediately after giving effect to the dividend payment, we have paid total dividends and made other restricted payments in excess of the permitted amounts. As of December 31, 2004, our coverage ratio for purposes of the debt incurrence test was 6.39 to 1, compared to 2.25 to 1 required in our indentures. Our adjusted consolidated net tangible assets exceeded 200% of our total indebtedness, as required in our indentures, by more than $2.2 billion.

The following table presents information about repurchases of our common stock during the three months ended December 31, 2004:

Period	Total Number of Shares Purchased[a]	Average Price Paid Per Share[a]	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs[b]
October 1, 2004 through October 31, 2004	35,879	$16.143	—	—
November 1, 2004 through November 30, 2004	50,450	$16.886	—	—
December 1, 2004 through December 31, 2004	36,583	$17.025	—	—
Total	122,912	$16.710	—	—

(a) Includes 98,386 shares purchased in the open market for the matching contributions we make to our 401(k) plans and the deemed surrender to the Company of 24,526 shares of common stock to pay the exercise price in connection with the exercise of employee stock options.

(b) We make matching contributions to our 401(k) plans and 401(k) make-up plan using Chesapeake common stock which is held in treasury or is purchased by the respective plan trustees in the open market. The plans contain no limitation on the number of shares that may be purchased for purposes of Company contributions. There are no other repurchase plans or programs currently authorized by the Board of Directors.

ITEM 6. *Selected Financial Data*

The following table sets forth selected consolidated financial data of Chesapeake for the years ended December 31, 2004, 2003, 2002, 2001 and 2000. The data are derived from our audited consolidated financial statements revised to reflect the reclassification of certain items. In addition to changes in the annual average prices for oil and gas and increased production from drilling activity, significant acquisitions in recent years also impacted comparability between years. See notes 11 and 13 to notes to financial statements. The table should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements, including the notes, appearing in Items 7 and 8 of this report.

	Years Ended December 31,				
	2004	2003	2002	2001	2000
	($ in thousands, except per share data)				
Statement of Operations Data:					
Revenues:					
Oil and gas sales	$1,936,176	$1,296,822	$ 568,187	$ 820,318	$ 470,170
Oil and gas marketing sales	773,092	420,610	170,315	148,733	157,782
Total revenues	2,709,268	1,717,432	738,502	969,051	627,952
Operating costs:					
Production expenses	204,821	137,583	98,191	75,374	50,085
Production taxes	103,931	77,893	30,101	33,010	24,840
General and administrative expenses:					
General and administrative (excluding stock-based compensation)	32,217	22,808	17,262	13,649	12,938
Stock-based compensation	4,828	945	356	800	239
Oil and gas marketing expenses	755,314	410,288	165,736	144,373	152,309
Oil and gas depreciation, depletion and amortization	582,137	369,465	221,189	172,902	101,291
Depreciation and amortization of other assets	29,185	16,793	14,009	8,663	7,481
Provision for legal settlements	4,500	6,402	—	—	—
Total operating costs	1,716,933	1,042,177	546,844	448,771	349,183
Income from operations	992,335	675,255	191,658	520,280	278,769
Other income (expense):					
Interest and other income	4,476	2,827	7,340	2,877	3,649
Interest expense	(167,328)	(154,356)	(112,031)	(98,321)	(86,256)
Loss on investment in Seven Seas	—	(2,015)	(17,201)	—	—
Loss on repurchases or exchanges of Chesapeake debt	(24,557)	(20,759)	(2,626)	(76,667)	—
Impairments of investments in securities	—	—	—	(10,079)	—
Gain on sale of Canadian subsidiary	—	—	—	27,000	—
Gothic standby credit facility costs	—	—	—	(3,392)	—
Total other income (expense)	(187,409)	(174,303)	(124,518)	(158,582)	(82,607)
Income before income taxes and cumulative effect of accounting change	804,926	500,952	67,140	361,698	196,162
Income tax expense (benefit):					
Current	—	5,000	(1,822)	3,565	—
Deferred	289,771	185,360	28,676	140,727	(259,408)
Total income tax expense (benefit)	289,771	190,360	26,854	144,292	(259,408)
Net income before cumulative effect of accounting change, net of tax	515,155	310,592	40,286	217,406	455,570
Cumulative effect of accounting change, net of income taxes of $1,464,000	—	2,389	—	—	—
Net Income	515,155	312,981	40,286	217,406	455,570
Preferred stock dividends	(39,506)	(22,469)	(10,117)	(2,050)	(8,484)
Gain (loss) on conversion/exchange of preferred stock	(36,678)	—	—	—	6,574
Net income available to common shareholders	$ 438,971	$ 290,512	$ 30,169	$ 215,356	$ 453,660
Earnings per common share—basic:					
Income before cumulative effect of accounting change	$ 1.73	$ 1.36	$ 0.18	$ 1.33	$ 3.52
Cumulative effect of accounting change	—	0.02	—	—	—
	$ 1.73	$ 1.38	$ 0.18	$ 1.33	$ 3.52
Earnings per common share— assuming dilution:					
Income before cumulative effect of accounting change	$ 1.53	$ 1.20	$ 0.17	$ 1.25	$ 3.01
Cumulative effect of accounting change	—	0.01	—	—	—
	$ 1.53	$ 1.21	$ 0.17	$ 1.25	$ 3.01
Cash dividends declared per common share	$ 0.170	$ 0.135	$ 0.060	$ —	$ —

	Years Ended December 31,				
	2004	2003	2002	2001	2000
	($ in thousands, except per share data)				
Cash Flow Data:					
Cash provided by operating activities before changes in working capital	$1,418,803	$ 903,929	$ 412,517	$ 518,563	$ 305,804
Cash provided by operating activities	1,448,555	945,602	432,531	553,737	314,640
Cash used in investing activities	3,381,204	2,077,217	779,745	670,105	325,229
Cash provided by (used in) financing activities	1,898,964	924,559	477,257	234,507	(27,740)
Effect of exchange rate changes on cash	—	—	—	(545)	(329)
Balance Sheet Data (at end of period):					
Total assets	$8,244,509	$4,572,291	$2,875,608	$2,286,768	$1,440,426
Long-term debt, net of current maturities	3,075,109	2,057,713	1,651,198	1,329,453	944,845
Stockholders' equity	3,162,883	1,732,810	907,875	767,407	313,232

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

Financial Data

The following table sets forth certain information regarding the production volumes, oil and gas sales, average sales prices received and expenses for the periods indicated:

	Years Ended December 31,		
	2004	2003	2002
Net Production:			
Oil (mbbl)	6,764	4,665	3,466
Gas (mmcf)	322,009	240,366	160,682
Gas equivalent (mmcfe)	362,593	268,356	181,478
Oil and Gas Sales ($ in thousands):			
Oil sales	$ 260,915	$ 132,630	$ 88,495
Oil derivatives – realized gains (losses)	(69,267)	(12,058)	(1,092)
Oil derivatives – unrealized gains (losses)	3,454	(9,440)	(7,369)
Total oil sales	195,102	111,132	80,034
Gas sales	1,789,275	1,171,050	470,913
Gas derivatives – realized gains (losses)	(85,634)	(5,331)	97,138
Gas derivatives – unrealized gains (losses)	37,433	19,971	(79,898)
Total gas sales	1,741,074	1,185,690	488,153
Total oil and gas sales	$1,936,176	$1,296,822	$568,187
Average Sales Price (excluding gains (losses) on derivatives):			
Oil ($ per bbl)	$ 38.57	$ 28.43	$ 25.53
Gas ($ per mcf)	$ 5.56	$ 4.87	$ 2.93
Gas equivalent ($ per mcfe)	$ 5.65	$ 4.86	$ 3.08
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Oil ($ per bbl)	$ 28.33	$ 25.85	$ 25.22
Gas ($ per mcf)	$ 5.29	$ 4.85	$ 3.54
Gas equivalent ($ per mcfe)	$ 5.23	$ 4.79	$ 3.61
Expenses ($ per mcfe):			
Production expenses	$ 0.56	$ 0.51	$ 0.54
Production taxes (a)	$ 0.29	$ 0.29	$ 0.17
General and administrative expenses:			
General and administrative expenses (excluding stock-based compensation)	$ 0.09	$ 0.08	$ 0.10
Stock-based compensation	$ 0.01	$ 0.00	$ 0.00
Oil and gas depreciation, depletion and amortization	$ 1.61	$ 1.38	$ 1.22
Depreciation and amortization of other assets	$ 0.08	$ 0.06	$ 0.08
Interest expense (b)	$ 0.45	$ 0.55	$ 0.61
Interest Expense ($ in thousands):			
Interest expense	$ 162,781	$ 151,676	$114,695
Interest rate derivatives – realized (gains) losses	(791)	(3,859)	(3,415)
Interest rate derivatives – unrealized (gains) losses	5,338	6,539	751
Total interest expense	$ 167,328	$ 154,356	$112,031
Net Wells Drilled	546	456	279
Net Producing Wells as of the End of Period	8,058	5,873	4,237

(a) Production taxes in 2004 include a benefit of \$6.8 million, or \$0.02 per mcfe, from 2003 severance tax credits.
(b) Includes the effects of realized gains or (losses) from interest rate derivatives, but does not include the effects of unrealized gains or (losses) from interest rate derivatives.

We manage our business as two separate segments, an exploration and production segment and a marketing segment. We refer you to note 8 of the notes to our consolidated financial statements appearing in Item 8 of this report, which summarizes by segment our net income and capital expenditures for 2004, 2003 and 2002 and our assets as of December 31, 2004, 2003 and 2002.

Executive Summary

Chesapeake is the fourth largest independent producer of natural gas in the U.S. and owns interests in approximately 20,000 producing oil and gas wells. Our primary operating area is the Mid-Continent region of the United States, which includes Oklahoma, western Arkansas, southwestern Kansas and the Texas Panhandle, and we are building significant secondary operating areas in the South Texas and Texas Gulf Coast region, the Permian Basin of western Texas and eastern New Mexico and in the Ark-La-Tex area of central and eastern Texas and northern Louisiana.

Our revenues, operating results, profitability and future growth depend on our ability to find, develop and acquire oil and gas reserves that are economically recoverable based on prevailing prices for natural gas and oil. We favor gas over oil, strive to establish regional dominance in our operating areas, have grown through a combination of drilling and acquisitions and manage price risk through opportunistic oil and natural gas hedging. We believe we have the largest onshore U.S. inventories of leasehold and 3-D seismic data (more than 3.3 million and 9.9 million net acres, respectively) with more than a seven year drilling backlog of 7,000 locations.

Oil and natural gas production for 2004 was 362.6 bcfe, an increase of 94.2 bcfe, or 35%, over the 268.4 bcfe produced in 2003. We have increased our production for 15 consecutive years and 14 consecutive quarters. During these 14 quarters, Chesapeake's domestic production has increased 186%, for an average compound quarterly growth rate of 8% and an average compound annual growth rate of 35%. We believe this is one of the two best operating performances in the industry during this time period.

In addition to increased oil and natural gas production, the prices we received were higher in 2004 than in 2003. On a natural gas equivalent basis, weighted average prices (excluding the effect of unrealized gains or losses on derivatives) were \$5.23 per mcfe in 2004 compared to \$4.79 per mcfe in 2003. The increase in prices resulted in an increase in revenue of \$157.6 million, and increased production resulted in an increase in revenue of \$451.4 million, for a total increase in revenue of \$609.0 million (excluding the effect of unrealized gains or losses on derivatives). In each of the core operating areas where Chesapeake sells its oil and natural gas, established marketing and transportation infrastructures exist thereby contributing to high wellhead price realizations on all properties in which we own an economic interest.

Chesapeake began 2004 with estimated proved reserves of 3,169 bcfe and ended the year with 4,902 bcfe. Taking into account production of 362.6 bcfe, reserve replacement during the year was 2,096 bcfe, or 578% of our production. This compares to reserve replacement of 459% and 334% for 2003 and 2002, respectively. Reserve additions through the drill bit were 962 bcfe (including 141 bcfe from performance revisions and 5 bcfe from revisions due to oil and natural gas price increases), or 46% of the total increase in 2004, and reserve additions through acquisitions, net of miscellaneous divestitures, were 1,134 bcfe, or 54% of the total increase. Our decline rate on producing properties is projected to be 26% in the first year (2005), 18% in year two, 14% in year three, 12% in year four and 11% in year five.

During 2004, Chesapeake drilled 561 (425 net) operated wells and participated in another 890 (121 net) wells operated by other companies. Chesapeake's drilling costs were \$756.0 million for operated wells and \$235.9 million for non-operated wells. The company's success rate was 96%. Our investment in leasehold and

3-D seismic data totaled $299.8 million (exclusive of leases acquired through acquisitions) and our acquisition expenditures totaled $2,112.4 million during 2004 (excluding $464 million of deferred taxes in connection with certain corporate acquisitions.)

During 2004, we received net proceeds of $2.1 billion through issuances of $650 million of common equity, $313 million of preferred equity (4.125% convertible preferred stock), $300 million principal amount of 7.5% Senior Notes due 2014, $300 million principal amount of 7.0% Senior Notes due 2014 and $600 million principal amount of 6.375% Senior Notes due 2015. As of December 31, 2004, the company's debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders' equity) was 49%, compared to 54% as of December 31, 2003. Additionally, through debt repurchases and exchanges completed in 2004, we have extended the average maturity of our long-term debt to over nine years and have lowered our average interest rate to approximately 7.3%.

During 2004, all of our outstanding 6.75% preferred stock was converted into 19,467,482 shares of common stock (at a conversion price of $7.70 per share). Also during 2004, we exchanged 4,496,890 shares of our outstanding 6.0% preferred stock for 23,979,817 shares of common stock. In March 2004, we paid $42.1 million representing the balance outstanding on our 7.875% Senior Notes upon their maturity and we redeemed the $4.3 million outstanding balance of our 8.5% Senior Notes due 2012. In December 2004, we repurchased and retired $190.8 million of our 8.375% Senior Notes due 2008 for cash. We subsequently repurchased and retired an additional $11.0 million of our 8.375% Senior Notes due 2008 for cash in January 2005.

We intend to continue to focus on improving the strength of our balance sheet. We believe our business strategy and operational performance will lead to an investment grade credit rating for our unsecured debt in the future.

Liquidity and Capital Resources

Sources of Liquidity and Uses of Funds

Our primary source of liquidity to meet operating expenses and fund capital expenditures (other than for certain acquisitions) is cash flow from operations. Based on our current production, price and expense assumptions, we expect cash flow from operations will exceed our drilling capital expenditures in 2005. Our budget for drilling, land and seismic activities during 2005 is currently between $1.4 billion and $1.5 billion. While we believe this level of exploration and development will be sufficient to increase our reserves in 2005 and achieve our target of a 10% to 20% increase in production over 2004 production (inclusive of acquisitions completed in 2005 through the filing date of this report but without regard to any additional acquisitions that may be completed in 2005), higher drilling and field operating costs, drilling results that alter planned development schedules, acquisitions or other factors could cause us to revise our drilling program, which is largely discretionary. Any cash flow from operations not needed to fund our drilling program will be available for acquisitions, debt repayment or other general corporate purposes in 2005.

Cash provided by operating activities (exclusive of changes in assets and liabilities) was $1,418.8 million in 2004, compared to $903.9 million in 2003 and $412.5 million in 2002. The $514.9 million increase from 2003 to 2004 was primarily due to higher realized prices and higher volumes of oil and gas production. The $491.4 million increase from 2002 to 2003 was primarily due to higher prices and higher volumes produced. We expect that 2005 production volumes will be higher than in 2004 and that cash provided by operating activities in 2005 will exceed 2004 levels. While a precipitous decline in gas prices in 2005 would significantly affect the amount of cash flow that would be generated from operations, we have 34% of our expected oil production in 2005 hedged at an average NYMEX price of $41.02 per barrel of oil and 51% of our expected natural gas production in 2005 hedged at an average NYMEX price of $6.27 per mcf. This level of hedging provides certainty of the cash flow we will receive for a substantial portion of our 2005 production. Depending on changes in oil and gas futures markets and management's view of underlying oil and natural gas supply and demand trends, however, we may increase or decrease our current hedging positions.

Based on fluctuations in natural gas and oil prices, our hedging counterparties may require us to deliver cash collateral or other assurances of performance from time to time. At December 31, 2004 and March 2, 2005, we had $66 million and $61 million, respectively, of letters of credit securing our performance of hedging contracts. To mitigate the liquidity impact of those collateral requirements, we have negotiated caps on the amount of collateral that we might be required to post with five of our counterparties. All of our existing commodity hedges that are not under our secured hedge facility are with these counterparties and the maximum amount of collateral that we would be required to post with these counterparties is capped at $230 million.

A significant source of liquidity is our $1.25 billion revolving bank credit facility which matures in January 2010. At March 2, 2005, there was $749 million of borrowing capacity available under the revolving bank credit facility. We use the facility to fund daily operating activities and acquisitions as needed. We borrowed $2,160 million and repaid $2,101 million in 2004, and we borrowed and repaid $738 million in 2003 and $253 million in 2002 under our bank credit facility. We incurred $2.2 million, $2.5 million and $2.9 million of financing costs related to our revolving credit facility in 2004, 2003 and 2002, respectively, as a result of amendments to the credit facility agreement.

We believe that our available cash, cash provided by operating activities and funds available under our revolving bank credit facility will be sufficient to fund our operating, interest and general and administrative expenses, our capital expenditure budget, our short-term contractual obligations and dividend payments at current levels for the foreseeable future. Our revolving bank credit facility and secured hedge facility are both syndicated facilities, neither of which contain material adverse or adequate assurance clauses. Although the applicable interest rates and commitment fees in our bank credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, neither the bank facility nor the secured hedge facility contain provisions which would trigger an acceleration of amounts due under the facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

The public and institutional markets have been our principal source of capital to finance certain of our acquisitions. We have sold debt and equity in both public and private offerings in the past, and we expect that these sources of capital will continue to be available to us in the future for acquisitions. Nevertheless, we caution that ready access to capital on reasonable terms and the availability of desirable acquisition targets at attractive prices are subject to many uncertainties, as explained under "Risk Factors" in Item 1—Business.

The following table reflects the proceeds from sales of securities we issued in 2004, 2003 and 2002 ($ in millions):

	2004		2003		2002	
	Total Proceeds	**Net Proceeds**	**Total Proceeds**	**Net Proceeds**	**Total Proceeds**	**Net Proceeds**
Unsecured senior notes guaranteed by subsidiaries	$1,200.0	$1,166.0	$ 500.0	$ 485.4	$450.0	$439.4
Convertible preferred stock	313.3	304.9	402.5	390.4	—	—
Common stock	650.0	624.2	186.3	177.4	172.5	164.1
Total	$2,163.3	$2,095.1	$1,088.8	$1,053.2	$622.5	$603.5

We filed a $600 million "universal shelf" registration statement with the Securities and Exchange Commission on September 28, 2004. Securities issued under this shelf may be in the form of common stock, preferred stock, depository shares representing fractional shares of preferred stock or debt securities of Chesapeake. A prospectus supplement will be prepared at the time of a debt or equity offering and will contain specific information about the security issued and the use of proceeds. No securities have been issued under this shelf registration statement.

In June 2004, we amended our certificate of incorporation to increase our authorized capital stock. The number of authorized shares of our common stock increased from 350 million to 500 million and the number of authorized shares of our preferred stock increased from 10 million to 20 million.

We paid dividends on our common stock of $38.9 million, $27.3 million and $5.0 million in 2004, 2003 and 2002, respectively, and we paid dividends on our preferred stock of $40.9 million, $20.9 million and $10.2 million in 2004, 2003 and 2002, respectively. We received $12.0 million, $9.3 million and $3.8 million from the exercise of employee and director stock options in 2004, 2003 and 2002, respectively. We paid $2.1 million to purchase treasury stock in 2003 to fund our matching contributions to our 401(k) make-up plan.

Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists increased by $88.3 million and $28.3 million in 2004 and 2003, respectively. All disbursements are funded on the day they are presented to our bank using available cash on hand or draws on our credit facility.

Historically, we have used significant funds to purchase and retire outstanding senior notes issued by Chesapeake. The following table shows our purchases and exchanges of senior notes for 2004, 2003 and 2002, respectively ($ in millions):

	Senior Notes Activity				
For the Year Ended December 31, 2004:	**Retired**	**Premium**	**Other(f)**	**Issued**	**Cash Paid**
8.375% Senior Notes due 2008	$190.8	$16.1	$ 0.5	—	$207.4
7.875% Senior Notes due 2004	42.1	—	—	—	42.1
8.5% Senior Notes due 2012	4.3	0.2	—	—	4.5
8.125% Senior Notes due 2011 (a)	482.8	—	62.1	(534.2)	10.7
	$720.0	$16.3	$62.6	$(534.2)	$264.7
For the Year Ended December 31, 2003:					
8.5% Senior Notes due 2012	$106.4	$ 6.7	$ —	$ —	$113.1
8.5% Senior Notes due 2012 (b)	32.0	—	1.5	(33.5)	—
8.375% Senior Notes due 2008 (c)	27.9	—	1.6	(29.5)	—
8.375% Senior Notes due 2008 and 8.125% Senior Notes due 2011 (d)	22.9	—	0.8	(23.7)	—
8.375% Senior Notes due 2008 and 8.125% Senior Notes due 2011 (e)	61.2	—	2.6	(63.8)	—
	$250.4	$ 6.7	$ 6.5	$(150.5)	$113.1
For the Year Ended December 31, 2002:					
7.875% Senior Notes due 2004	$107.9	$ 3.7	$ —	$ —	$111.6

(a) We issued $63.7 million of our 7.75% Senior Notes and $470.5 million of our 6.875% Senior Notes.
(b) We issued $33.5 million of our 7.75% Senior Notes.
(c) We issued $29.5 million of our 7.75% Senior Notes.
(d) We issued $23.7 million of our 7.75% Senior Notes for $6.0 million 8.375% Senior Notes and $16.8 million 8.125% Senior Notes.
(e) We issued $63.8 million of our 7.5% Senior Notes for $6.3 million 8.375% Senior Notes and $54.9 million 8.125% Senior Notes.
(f) Includes adjustments to accrued interest and discount associated with notes retired and new notes issued, cash in lieu of fractional notes, transaction costs and fair value hedging adjustments.

Cash used in investing activities increased to $3,381.2 million in 2004, compared to $2,077.2 million in 2003 and $779.7 million in 2002. The following table shows our capital expenditures during these years ($ in millions):

	2004	2003	2002
Exploration and development of oil and gas properties	$1,276.3	$ 727.2	$400.2
Acquisitions of oil and gas companies, proved and unproved properties, net of cash acquired	1,914.7	1,261.3	331.7
Deposits for pending acquisitions	16.3	13.3	15.0
Cash paid for other investments	37.0	30.8	2.4
Additions to drilling rigs, plants, compressor and gathering systems	79.1	23.3	6.6
Additions to buildings and other fixed assets	70.7	49.4	30.6
Total	$3,394.1	$2,105.3	$786.5

Through divestitures of oil and gas properties, we received $12.0 million in 2004, $22.2 million in 2003 and $0.8 million, in 2002. Sales of other assets and recoveries of investments in securities of other companies provided $0.9 million, $5.8 million and $5.8 million of cash in 2004, 2003 and 2002, respectively.

During 2004, we took several steps to improve our capital structure, including the transactions described below under *Financing Transactions*. These transactions enabled us to extend our average maturity of long-term debt to over nine years with an average interest rate of approximately 7.3%. The company's debt as a percentage of total capitalization decreased to 49% and debt per mcfe of proved reserves decreased to $0.63 per mcfe. Maintaining a debt-to-total-capitalization ratio below 50% and reducing debt per mcfe of proved reserves to below $0.60 are key goals of our business strategy.

Our accounts receivable are primarily from purchasers of oil and natural gas ($347.1 million at December 31, 2004) and exploration and production companies which own interests in properties we operate ($68.2 million at December 31, 2004). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

Our liquidity is not dependent on the use of off-balance sheet financing arrangements, such as the securitization of receivables or obtaining access to assets through special purpose entities. We have not relied on off-balance sheet financing arrangements in the past and we do not intend to rely on such arrangements in the future as a source of liquidity. We are not a commercial paper issuer.

Investing Transactions

The following table outlines significant investing transactions that we completed in 2004 and in January and February 2005 ($ in millions):

Quarter	Year	Acquisition	Location	Amount
First	2004	Concho Resources, Inc.	Permian Basin and Mid-Continent	$ 420[(a)]
		Other	Texas Gulf Coast	65[(b)]
Second	2004	Greystone Petroleum, LLC	Ark-La-Tex	425
		Permian Resources Holdings, Inc.	Permian Basin	69
		Other	Mid-Continent	31
Third	2004	Bravo Natural Resources, Inc.	Mid-Continent	335
		Tilford Pinson Exploration, LLC	Mid-Continent	20
		Legend Natural Gas, LLP	South Texas	215
		Other	Mid-Continent	90
Fourth	2004	Hallwood Energy Corporation	Ark-La-Tex	292
		Other	Mid-Continent and Ark-La-Tex	78
				$2,040
First	2005	BRG Petroleum Corporation	Mid-Continent and Ark-La-Tex	$ 325[(c)]

(a) We paid $10 million of the purchase amount in 2003.
(b) We paid $3.3 million of the purchase amount in 2003.
(c) We paid $16.3 million of the purchase amount in 2004.

Financing Transactions

First Quarter 2004

- Completed a public offering of 23 million shares of common stock at $13.51 per share. Net proceeds of approximately $298.1 million were used to finance a portion of the acquisitions completed in January 2004.
- Issued 275,000 shares of 4.125% convertible preferred stock at $1,000 per share in a private placement. Net proceeds of approximately $267.7 million were used to pay outstanding borrowings under our revolving bank credit facility which were incurred as a result of acquisitions completed in the first quarter of 2004.
- Completed a public exchange offer in which we retired $458.5 million of our 8.125% Senior Notes due 2011 and $10.8 million of accrued interest and issued $72.8 million of our 7.75% Senior Notes due 2015 and $2.8 million of accrued interest and $433.5 million of our 6.875% Senior Notes due 2016 and $4.1 million of accrued interest.
- Issued an additional $37.0 million of our 6.875% Senior Notes due 2016 and $0.5 million of accrued interest in exchange for $24.3 million of our $8.125% Senior Notes due 2011 and $0.7 million of accrued interest and $9.1 million of our 7.75% Senior Notes due 2015 and $0.1 million of accrued interest in four private exchange transactions. No cash was received or paid in connection with this transaction.
- Paid $4.5 million (including a premium of $0.2 million) to redeem $4.3 million of 8.5% Senior Notes due 2012 representing all outstanding notes which were not tendered pursuant to a cash tender offer completed in December 2003.
- Paid $42.1 million representing the balance outstanding on our 7.875% Senior Notes that matured on March 15, 2004.

Second Quarter 2004

- Completed a private placement of $300 million of 7.5% Senior Notes due 2014. Net proceeds of approximately $288.6 million were used to finance a portion of the Greystone acquisition completed in June 2004.
- Issued an additional 38,250 shares of 4.125% convertible preferred stock upon exercise of an option we granted to the purchasers in a March 2004 private placement for net proceeds of $37.2 million.

Third Quarter 2004

- Completed a public offering of 23 million shares of common stock at $14.75 per share. Net proceeds of approximately $326.2 million were used to finance a portion of the Bravo, Legend and Tilford Pinson acquisitions and to repay amounts outstanding under our bank credit facility.
- Completed a private placement of $300 million of 7.0% Senior Notes due 2014. Net proceeds of approximately $294.3 million were used to finance a portion of the Bravo, Legend and Tilford Pinson acquisitions and to repay amounts outstanding under our revolving bank credit facility.

Fourth Quarter 2004

- Completed a private placement of $600 million of 6.375% Senior Notes due 2015. Net proceeds of approximately $583.1 million were used to finance the Hallwood acquisition completed in December 2004, repurchase our 8.375% Senior Notes due 2008 and repay amounts outstanding under our revolving bank credit facility.
- Paid $209.3 million (including premium of $16.1 million, accrued interest of $1.9 million and transaction costs of $0.5 million) for $190.8 million of 8.375% Senior Notes due 2008 pursuant to a cash tender offer.
- Completed a private exchange of $30.0 million of our 6.0% cumulative convertible preferred stock for 3.2 million shares of our common stock. No cash was received or paid in connection with this transaction.
- Completed a public exchange of $194.8 million of our 6.0% cumulative convertible preferred stock for 20.8 million shares of our common stock. No cash was received or paid in connection with this transaction.
- Completed a mandatory conversion of $149.9 million of our 6.75% cumulative convertible preferred stock for 19.5 million of our common stock. No cash was received or paid in connection with this transaction.

January and February 2005

- Amended our revolving bank credit facility to increase the committed borrowing base to $1.25 billion and extend the maturity of the facility to January 2010.
- Completed a private purchase of $11.0 million of our 8.375% Senior Notes due 2008 for $12.0 million (including premium of $0.8 million and accrued interest of $0.2 million).

Contractual Obligations

We currently have a $1.25 billion revolving bank credit facility which matures in January 2010. The credit facility was increased from $600 million to $1.25 billion in January 2005. As of December 31, 2004, we had $59.0 million of outstanding borrowings under this facility and had utilized $122.5 million of the facility for various letters of credit. Borrowings under the facility are collateralized by certain producing oil and gas properties and bear interest at either (i) the greater of the reference rate of Union Bank of California, N.A., or the federal funds effective rate plus 0.50% or (ii) London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are redetermined periodically. The unused portion of the facility is subject to an annual commitment fee that also varies according to our senior unsecured long-term debt ratings. Currently the annual commitment fee is 0.30%. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, sell properties, purchase or redeem our capital stock, make investments or loans, and create liens. Prior to its amendment and restatement in January 2005, the credit facility agreement required us to maintain a current ratio (as defined) of at least 1 to 1 and a fixed charge coverage ratio (as defined) of at least 2.5 to 1. At December 31, 2004, our current ratio was 1.1 to 1 and our fixed charge coverage ratio was 5.6 to 1. As amended, the agreement no longer includes a current ratio test. The 2.5 to 1 fixed charge coverage ratio continues to apply and a new financial covenant was added requiring an indebtedness to EBITDA ratio (as defined) not to exceed 3.5 to 1. Under this test, our indebtedness to EBITDA ratio at December 31, 2004 was 2.1 to 1. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million or more, would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $50 million.

Some of our commodity price and financial risk management arrangements require us to deliver cash collateral or other assurances of performance to the counterparties in the event that our payment obligations exceed certain levels. As of December 31, 2004, we were required to post $66 million of collateral in the form of letters of credit with respect to such derivative transactions. These collateral requirements were $61 million as of March 2, 2005. Future collateral requirements are uncertain and will depend on arrangements with our counterparties and fluctuations in natural gas and oil prices and interest rates. We currently have arrangements with five of our counterparties which limit the amount of collateral that we would be required to post with a counterparty to no more than $50 million each.

In May 2004, we entered into a secured natural gas hedging facility with a nationally recognized counterparty. Under this hedging facility, which matures in May 2009, we can enter into cash-settled natural gas commodity transactions, valued by the counterparty, for up to $600 million. Outstanding transactions under the facility are collateralized by certain oil and gas properties, exclusive of the oil and gas properties that collateralize our revolving bank credit facility. The hedging facility is subject to an annual fee of 0.30% of the maximum total capacity and a 1.0% exposure fee, which is assessed quarterly on the average of the daily negative fair market value amounts, if any, during the quarter. As of December 31, 2004, the fair market value of the natural gas hedging transactions related to the hedging facility was an asset of $56.4 million.

The hedging facility contains the standard representations and default provisions that are typical of such agreements. The agreement also contains various restrictive provisions which govern the aggregate gas production volumes that we are permitted to hedge under all of our agreements at any one time. The hedging facility is guaranteed by Chesapeake and its subsidiaries.

Our subsidiary, Chesapeake Exploration Limited Partnership, is the borrower under our revolving bank credit facility and is the named party of our hedging facility. The facilities are guaranteed by Chesapeake and all its other subsidiaries. Our revolving bank credit facility and secured hedge facility are both syndicated facilities, neither of which contain material adverse or adequate assurance clauses. Although the applicable interest rates and commitment fees in our bank credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, neither the bank facility nor the secured hedge facility contain provisions which would trigger an acceleration of amounts due under the facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

In addition to outstanding revolving bank credit facility borrowings discussed above, as of December 31, 2004, senior notes represented approximately $3.0 billion of our long-term debt and consisted of the following ($ in thousands):

8.375% senior notes due 2008	$ 18,990
8.125% senior notes due 2011	245,407
9.0% senior notes due 2012	300,000
7.5% senior notes due 2013	363,823
7.0% senior notes due 2014	300,000
7.5% senior notes due 2014	300,000
7.75% senior notes due 2015	300,408
6.375% senior notes due 2015	600,000
6.875% senior notes due 2016	670,437
Discount on senior notes	(84,924)
Premium for interest rate swap	1,968
	$3,016,109

In January 2005, we purchased $11.0 million of our 8.375% Senior Notes due 2008. No scheduled principal payments are required on any of the senior notes until 2008, when $8.0 million is due.

Debt ratings for the senior notes are Ba3 by Moody's Investor Service (positive outlook), BB- by Standard & Poor's Ratings Services (positive outlook) and BB by Fitch Ratings.

Our senior notes are unsecured senior obligations of Chesapeake and rank equally with all of our other unsecured indebtedness. All of our wholly owned subsidiaries guarantee the notes including Chesapeake Energy Marketing, Inc., Mayfield Processing, L.L.C. and MidCon Compression, L.P., for which the guarantee became effective September 21, 2004. The indentures permit us to redeem the senior notes at any time at specified make-whole or redemption prices. The indentures contain covenants limiting our ability and our restricted subsidiaries' ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; incur liens; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. The debt incurrence covenants do not presently restrict our ability to borrow under or expand our secured credit facility. As of December 31, 2004, we estimate that secured commercial bank indebtedness of approximately $1.9 billion could have been incurred under the most restrictive indenture covenant.

The table below summarizes our contractual obligations as of December 31, 2004 ($ in thousands):

	Payments Due By Period				
Contractual Obligations	**Total**	**Less than 1 Year**	**1-3 Years**	**3-5 Years**	**More than 5 Years**
Long-term debt obligations	$3,158,065	$ —	$ —	$18,990	$3,139,075
Capital lease obligations	420	120	300	—	—
Operating lease obligations	7,017	2,415	2,650	853	1,099
Purchase obligations	—	—	—	—	—
Standby letters of credit	122,788	122,788	—	—	—
Other long-term obligations	1,468	1,468	—	—	—
Total contractual cash obligations	$3,289,758	$126,791	$2,950	$19,843	$3,140,174

Hedging Activities

Oil and Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. Executive management is involved in all risk management activities and the Board of Directors reviews the company's hedging program at every Board of Director's meeting. We believe we have sufficient internal controls to prevent unauthorized hedging. As of December 31, 2004, our oil and gas derivative instruments were comprised of swaps, cap-swaps, basis protection swaps, call options and collars. Item 7A—Quantitative and Qualitative Disclosures About Market Risk contains a description of each of these instruments. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

Hedging allows us to predict with greater certainty the effective prices we will receive for our hedged oil and gas production. We closely monitor the fair value of our hedging contracts and may elect to settle a contract prior to its scheduled maturity date in order to lock in a gain or loss. Commodity markets are volatile, and Chesapeake's hedging activity is dynamic.

Mark-to-market positions under oil and gas hedging contracts fluctuate with commodity prices. As described above under "Contractual Obligations", we may be required to deliver cash collateral or other assurances of performance if our payment obligations to our hedging counterparties exceed levels stated in our contracts.

Realized gains and losses from our oil and gas derivatives resulted in a net decrease in oil and gas sales of $154.9 million or $0.43 per mcfe in 2004, a net decrease of $17.4 million or $0.06 per mcfe in 2003 and a net increase of $96.0 million or $0.53 per mcfe in 2002. Oil and gas sales also include changes in the fair value of oil and gas derivatives that do not qualify as cash flow hedges under SFAS 133, as well as gains (losses) on ineffectiveness of instruments designated as cash flow hedges. Unrealized gains (losses) included in oil and gas sales in 2004, 2003 and 2002 were $40.9 million, $10.5 million and ($87.3) million, respectively. Included in these unrealized gains (losses) are gains (losses) on ineffectiveness of cash flow hedges of ($8.2) million in 2004, ($9.2) million in 2003 and ($3.6) million in 2002.

Changes in the fair value of oil and gas derivative instruments designated as cash flow hedges, to the extent effective in offsetting cash flows attributable to the hedged commodities, and locked-in gains and losses of derivative contracts are recorded in accumulated other comprehensive income until being transferred to earnings in the month of related production. These unrealized losses, net of related tax effects, totaled $4.4 million, $20.3 million and $3.5 million as of December 31, 2004, 2003, and 2002, respectively. Based upon the market prices at December 31, 2004, we expect to transfer to earnings approximately $7.3 million of the income included in the balance of accumulated other comprehensive income during the next 12 months when the transactions actually occur. A detailed explanation of accounting for oil and gas derivatives under SFAS 133 appears under "Application of Critical Accounting Policies—Hedging" elsewhere in this Item 7.

The fair values of our oil and gas derivative instruments are recorded on our consolidated balance sheet as assets or liabilities. The estimated fair values of our oil and gas derivative instruments as of December 31, 2004 and 2003 are provided below:

	December 31,	
	2004	2003
	($ in thousands)	
Derivative assets (liabilities):		
Fixed-price gas swaps	$ 57,073	$(44,794)
Fixed-price gas locked swaps	(77,299)	1,777
Fixed-price gas cap-swaps	(48,761)	(18,608)
Fixed-price gas counter swaps	4,654	—
Gas basis protection swaps	122,287	46,205
Gas call options(a)	(5,793)	(17,876)
Fixed-price gas collars	(5,573)	—
Fixed-price oil cap-swaps	(8,238)	(11,692)
Estimated fair value	$ 38,350	$(44,988)

(a) After adjusting for the remaining $3.2 million and $16.8 million premium paid to Chesapeake by the counterparty, the cumulative unrealized loss related to these call options as of December 31, 2004 and 2003 was ($2.6) million and ($1.1) million, respectively.

As of December 31, 2004, we had hedged approximately 29% of our expected oil production and 42% of our expected natural gas production in 2005. In addition, hedging contracts were in place for approximately 9% of expected natural gas production in 2006. Natural gas basis protection swaps extend to 2009. A detailed listing of our oil and gas derivatives by year of maturity is included in Item 7A—Quantitative and Qualitative Disclosures About Market Risk.

Additional information concerning changes in the fair value of our oil and gas derivative instruments is as follows:

	December 31,		
	2004	2003	2002
	($ in thousands)		
Fair value of contracts outstanding, beginning of year	$ (44,988)	$(14,533)	$157,309
Change in fair value of contracts during the period	(69,927)	(31,078)	(52,419)
Contracts realized or otherwise settled during the period	154,901	17,389	(96,046)
Fair value of new contracts when entered into during the period	(5,369)	(16,766)	(45,603)
Fair value of contracts when closed during the period	3,733	—	22,226
Fair value of contracts outstanding, end of year	$ 38,350	$(44,988)	$ (14,533)

Interest Rate Derivatives

We also utilize hedging strategies to manage our exposure to changes in interest rates. To the extent interest rate swaps have been designated as fair value hedges, changes in the fair value of the derivative instrument and the corresponding debt are reflected as adjustments to interest expense in the corresponding months covered by the derivative agreement. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

As of December 31, 2004, the following interest rate swaps to convert a portion of our long-term fixed rate debt to floating rate debt were outstanding:

Term	Notional Amount	Fixed Rate	Floating Rate	Fair Value as of December 31, 2004
				($ in thousands)
November 2004 – June 2014	$75,000,000	7.500%	6-month LIBOR in arrears plus 254 basis points	$(333)
November 2004 – January 2015	$75,000,000	7.750%	6-month LIBOR in arrears plus 291 basis points	$(914)
September 2004 – August 2012	$75,000,000	9.000%	6-month LIBOR plus 452 basis points	$(269)

During 2004, we entered into and subsequently closed five separate interest rate swaps for a total gain of $3.8 million. These interest rate swaps were designated as fair value hedges of the related senior notes. The settlement amounts received will be amortized as a reduction to interest expense over the remaining terms of the related senior notes. The senior notes hedged mature in 2014 and 2015.

In 2005, we closed the 7.5% and 7.75% interest rate swaps for gains totaling $0.8 million. These interest rate swaps were designated as fair value hedges of the related senior notes. The settlement amounts received will be amortized as a reduction to interest expense over the remaining terms of the related senior notes. The senior notes hedged mature in 2014 and 2015.

In March 2004, Chesapeake entered into an interest rate swap which requires Chesapeake to pay a fixed rate of 8.68% while the counterparty pays Chesapeake a floating rate of six month LIBOR plus 0.75% on a notional amount of $142.7 million. The counterparty may elect to terminate the swap and cause it to be settled at the then current estimated fair value of the interest rate swap on March 15, 2005 and annually thereafter until March 15, 2011. The interest rate swap expires on March 15, 2012. Chesapeake may elect to terminate the swap and cause it to be settled at the then current estimated fair value of the interest rate swap at any time during the term of the swap.

As of December 31, 2004, the fair value of the interest rate swap was a liability of $34.3 million. Because the interest rate swap is not designated as a fair value hedge, changes in the fair value of the swap are recorded as adjustments to interest expense. In 2004, interest expense related to the swap included an unrealized loss of $4.2 million and a realized loss of $2.2 million.

In January 2004, Chesapeake acquired a $50 million interest rate swap as part of the purchase of Concho Resources Inc. Under the terms of the interest rate swap, the counterparty pays Chesapeake a floating three-month LIBOR rate and Chesapeake pays a fixed rate of 2.875%. Payments are made quarterly and the interest rate swap extends through September 2005. An initial liability of $0.6 million was recorded based on the fair value of the interest rate swap at the time of acquisition. As of December 31, 2004, the interest rate swap had a negligible fair value. Because this instrument is not designated as a fair value hedge, an unrealized gain of $0.1 million was recognized in 2004 as part of interest expense.

Results of Operations

General. For the year ended December 31, 2004, Chesapeake had net income of $515.2 million, or $1.53 per diluted common share, on total revenues of $2,709.3 million. This compares to net income of $313.0 million, or $1.21 per diluted common share, on total revenues of $1,717.4 million during the year ended December 31, 2003, and net income of $40.3 million, or $0.17 per diluted common share, on total revenues of $738.5 million during the year ended December 31, 2002. The 2004 net income includes, on a pre-tax basis, a $24.6 million loss on repurchased debt, a $4.5 million provision for legal settlements and $35.5 million in net unrealized gains on oil and gas and interest rate derivatives. The 2003 net income includes, on a pre-tax basis, a $20.8 million loss on repurchased debt, a $6.4 million provision for legal settlements, $4.0 million in net unrealized gains on oil and gas and interest rate derivatives and a $2.0 million impairment of our investment in Seven Seas Petroleum Inc. The 2002 net income includes, on a pre-tax basis, $88.0 million in net unrealized losses on oil and gas and interest rate derivatives, a $17.2 million impairment of our investment in Seven Seas Petroleum Inc. and a $2.6 million loss on repurchased debt.

Oil and Gas Sales. During 2004, oil and gas sales were $1,936.2 million compared to $1,296.8 million in 2003 and $568.2 million in 2002. In 2004, Chesapeake produced 362.6 bcfe at a weighted average price of $5.23 per mcfe, compared to 268.4 bcfe produced in 2003 at a weighted average price of $4.79 per mcfe, and 181.5 bcfe produced in 2002 at a weighted average price of $3.61 per mcfe (weighted average prices for all years discussed exclude the effect of unrealized gains or (losses) on derivatives of $40.9 million, $10.5 million and ($87.3) million in 2004, 2003 and 2002, respectively). The increase in prices in 2004 resulted in an increase in revenue of $157.6 million and increased production resulted in a $451.4 million increase, for a total increase in revenues of $609.0 million (excluding unrealized gains or losses on oil and gas derivatives). The increase in production from period to period was due to the combination of production growth from drilling as well as acquisitions completed during those periods.

For 2004, we realized an average price per barrel of oil of $28.33, compared to $25.85 in 2003 and $25.22 in 2002 (weighted average prices for all years discussed exclude the effect of unrealized gains or losses on derivatives). Natural gas prices realized per mcf (excluding unrealized gains or losses on derivatives) were $5.29, $4.85 and $3.54 in 2004, 2003 and 2002, respectively. Realized gains or losses from our oil and gas derivatives resulted in a net decrease in oil and gas revenues of $154.9 million or $0.43 per mcfe in 2004, a net decrease of $17.4 million or $0.06 per mcfe in 2003 and a net increase of $96.0 million or $0.53 per mcfe in 2002.

A change in oil and gas prices has a significant impact on our oil and gas revenues and cash flows. Assuming 2004 production levels, a change of $0.10 per mcf of gas sold would result in an increase or decrease in revenues and cash flow of approximately $32.2 million and $30.4 million, respectively, and a change of $1.00 per barrel of oil sold would result in an increase or decrease in revenues and cash flow of approximately $6.8 million and $6.4 million, respectively, without considering the effect of hedging activities.

The following table shows our production by region for 2004, 2003 and 2002:

	Years Ended December 31,					
	2004		2003		2002	
	Mmcfe	Percent	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	268,459	74%	233,559	87%	147,348	81%
South Texas and Texas Gulf Coast	42,427	12	15,546	6	16,349	9
Permian Basin	29,468	8	8,496	3	7,637	4
Ark-La-Tex	19,640	5	7,776	3	6,915	4
Other	2,599	1	2,979	1	3,229	2
Total Production	362,593	100%	268,356	100%	181,478	100%

Natural gas production represented approximately 89% of our total production volume on an equivalent basis in 2004, compared to 90% in 2003 and 89% in 2002.

Oil and Gas Marketing Sales. Chesapeake realized $773.1 million in oil and gas marketing sales to third parties in 2004, with corresponding oil and gas marketing expenses of $755.3 million, for a net margin of $17.8 million. Marketing activities are substantially for third parties who are owners in Chesapeake operated wells. This compares to sales of $420.6 million and $170.3 million, expenses of $410.3 million and $165.7 million, and margins of $10.3 million and $4.6 million in 2003 and 2002, respectively. In 2004 and 2003, Chesapeake realized an increase in volumes and prices related to oil and gas marketing sales as compared to the previous year.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $204.8 million in 2004, compared to $137.6 million and $98.2 million in 2003 and 2002, respectively. On a unit-of-production basis, production expenses were $0.56 per mcfe in 2004 compared to $0.51 and $0.54 per mcfe in 2003 and 2002, respectively. The increase in 2004 was primarily due to higher field service costs. The decrease in costs on a per unit basis in 2003 is due primarily to lower production costs associated with properties acquired during the year and realization of efficiencies from a higher scale of operations in the Mid-Continent region. We expect that production expenses per mcfe for 2005 will range from $0.62 to $0.67.

Production Taxes. Production taxes were $103.9 million in 2004 compared to $77.9 million in 2003 and $30.1 million in 2002. On a unit-of-production basis, production taxes were $0.29 per mcfe in 2004 compared to $0.29 per mcfe in 2003 and $0.17 per mcfe in 2002. Included in 2004 is a credit of $6.8 million, or $0.02 per mcfe, related to certain Oklahoma severance tax abatements for the period July 2003 through December 2003. In April 2004, the Oklahoma Tax Commission concluded that a pre-determined oil and gas price cap for 2003 sales had not been exceeded (on a statewide basis) and notified the company that it was eligible to receive certain severance tax abatements for the period from July 1, 2003 through June 30, 2004. The company had previously estimated that the average oil and gas sales prices in Oklahoma (on a statewide basis) could exceed the price cap, and did not reflect the benefit from these potential severance tax abatements until the first quarter of 2004. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil and gas prices are higher. We expect production taxes per mcfe to range from $0.38 to $0.40 during 2005 based on an assumption that oil and natural gas wellhead prices will range from $6.00 to $6.50 per mcfe.

General and Administrative Expense (Excluding Stock-Based Compensation). General and administrative expenses, which are net of internal payroll and non-payroll costs capitalized in our oil and gas properties (see note 11 of notes to consolidated financial statements), were $32.2 million in 2004, $22.8 million in 2003 and $17.3 million in 2002. The increase in 2004 and 2003 was the result of the company's growth related to the various acquisitions which occurred in 2004 and 2003 and the increase in drilling activity associated with the growth of our exploration activities. This growth has resulted in a substantial increase in employees and related costs. We anticipate that general and administrative expenses for 2005 will be between $0.10 and $0.11 per mcfe produced, which is approximately the same level as 2004.

Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $51.7 million, $35.5 million and $24.3 million of internal costs in 2004, 2003 and 2002, respectively, directly related to our oil and gas property acquisition, exploration and development efforts.

Stock-Based Compensation. Stock-based compensation was $4.8 million in 2004, $0.9 million in 2003 and $0.4 million in 2002. During 2004, 2.7 million shares of restricted stock were granted to employees. The cost of all outstanding restricted shares is amortized over a four-year period which resulted in the recognition of $6.3 million of stock-based compensation costs during 2004. Of this amount, $4.2 million was reflected as stock-based compensation expense (a sub-category of general and administrative costs) in the consolidated statements of operations, and the remaining $2.1 million was capitalized to oil and gas properties. Chesapeake did not issue restricted stock awards prior to 2004. Additionally, we recognized $0.6 million, $0.9 million and $0.4 million in stock-based compensation expense in 2004, 2003 and 2002, respectively, as a result of modifications made to previously issued stock options. Stock-based compensation was $0.01 per mcfe for 2004. We anticipate that stock-based compensation expense for 2005 will be between $0.04 and $0.06 per mcfe produced.

Provision for Legal Settlements. In 2004, we recorded a provision for legal settlement of $4.5 million related to certain pending litigation. In 2003, recorded a $6.4 million provision related to the settlement of a class-action lawsuit whereby we refunded certain royalty owners.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and gas properties was $582.1 million, $369.5 million and $221.2 million during 2004, 2003 and 2002, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs, and the related underlying reserves in the periods presented, was $1.61, $1.38 and $1.22 in 2004, 2003 and

2002, respectively. The increase in the average rate from $1.38 in 2003 to $1.61 in 2004 is primarily the result of higher drilling costs, higher costs associated with acquisitions and the recognition of the tax effect of acquisition costs in excess of tax basis acquired in certain corporate acquisitions. We expect the 2005 DD&A rate to be between $1.75 and $1.80 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $29.2 million in 2004, compared to $16.8 million in 2003 and $14.0 million in 2002. The increase in 2004 and 2003 was primarily the result of higher depreciation costs resulting from the acquisition of a processing plant, various gathering facilities, construction of new buildings at our corporate headquarters complex and at various field office locations and the purchase of additional information technology equipment and software in 2004 and 2003. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 39 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to fifteen years. To the extent drilling rigs are used to drill our wells, a substantial portion of the depreciation is capitalized in oil and gas properties as exploration or development costs. We expect 2005 depreciation and amortization of other assets to be between $0.09 and $0.11 per mcfe produced.

Interest and Other Income. Interest and other income was $4.5 million, $2.8 million and $7.3 million in 2004, 2003 and 2002, respectively. The 2004 income consisted of $2.1 million of interest income, $0.8 million of income related to earnings on investments, and $1.6 million of miscellaneous income. The 2003 income consisted of $1.0 million of interest income, a $0.4 million loss on our investment in Pioneer Drilling Company (AMEX:PDC), a $0.6 million gain on the final settlement of the sale of our Canadian subsidiary and $1.6 million of miscellaneous income. The 2002 income consisted of $2.9 million in interest income, $2.9 million of interest accrued on our investment in Seven Seas, a $0.5 million gain on the sale of our investment in RAM notes, a $0.3 million loss on our investment in Petroleum Place and $1.3 million of miscellaneous income.

Interest Expense. Interest expense increased to $167.3 million in 2004 compared to $154.4 million in 2003 and $112.0 million in 2002 as follows:

	Years Ended December 31,		
	2004	2003	2002
	($ in millions)		
Interest expense on senior notes and revolving bank credit facility	$194.5	$163.2	$118.5
Capitalized interest	(36.2)	(13.0)	(5.0)
Amortization of loan discount	4.5	1.6	1.1
Unrealized loss on interest rate derivatives	5.3	6.5	0.8
Realized gain on interest rate derivatives	(0.8)	(3.9)	(3.4)
Total interest expense	$167.3	$154.4	$112.0
Average long-term borrowings	$2,428	$1,932	$1,415

We use interest rate derivatives to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value of interest rate derivatives are recorded on the consolidated balance sheets as assets (liabilities) and the debt's carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Any resulting differences are recorded currently as ineffectiveness in the consolidated statements of operations as an adjustment to interest expense. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense. A detailed explanation of our interest rate derivative activity appears below in Item 7. Quantitative and Qualitative Disclosures About Market Risk.

Interest expense, excluding unrealized (gains) losses on derivatives, was $0.45 per mcfe in 2004 compared to $0.55 per mcfe in 2003 and $0.61 in 2002. We expect interest expense for 2005 to be between $0.43 and $0.47 per mcfe produced (before considering the effect of interest rate derivatives).

Loss on Investment in Seven Seas. In July 2001, Chesapeake purchased $22.5 million principal amount of 12% senior secured notes due 2004 issued by Seven Seas Petroleum Inc. and detachable seven-year warrants to purchase approximately 12.6 million shares of Seven Seas common stock at an exercise price of approximately $1.78 per share. In the third quarter of 2002, Chesapeake recorded an impairment of $4.8 million representing 100% of the cost allocated to our Seven Seas common stock warrants. During the fourth quarter of 2002, we recorded an additional impairment of $12.4 million to reduce our net investment in the senior secured notes, including accrued interest, to $7.5 million, representing Chesapeake's anticipated share of the net proceeds from the liquidation of Seven Seas' assets in bankruptcy. In the third quarter of 2003, we received approximately $5.5 million in proceeds from the sale of its principal assets. Seven Seas reported in October 2003 that it had no source of additional cash flow and only contingent assets remaining, the value of which was considered speculative. Accordingly, in the fourth quarter of 2003 we determined that any remaining assets of Seven Seas would not be adequate for us to realize the remaining investment on our books. At that time, we recorded an impairment of $2.0 million which reduced the carrying value of our investment to zero.

Loss on Repurchases or Exchanges of Debt. During the past three years we have repurchased or exchanged Chesapeake debt and incurred losses in connection with these transactions. The following table shows the losses related to these transactions for 2004, 2003 and 2002, respectively ($ in millions):

	Notes	Loss on Repurchases/Exchanges		
For the Year Ended December 31, 2004:	**Retired**	**Premium**	**Other(a)**	**Total**
8.375% Senior Notes due 2008	$190.8	$16.1	$ 1.5	$17.6
8.5% Senior Notes due 2012	4.3	0.2	0.7	0.9
8.125% Senior Notes due 2011	482.8	—	6.0	6.0
	$677.9	$16.3	$ 8.2	$24.5
For the Year Ended December 31, 2003:				
8.5% Senior Notes due 2012	$106.4	$ 6.7	$14.1(b)	$20.8
For the Year Ended December 31, 2002:				
7.875% Senior Notes due 2004	$107.9	$ 3.7	$ (1.1)(c)	$ 2.6

(a) Includes write-offs of discounts, deferred charges and interest rate derivatives associated with notes retired and transaction costs.

(b) Includes a $12.0 million loss that was recognized based on the hedging relationship between the notes and the interest rate derivative.

(c) Includes a $1.7 million gain that was recognized based on the hedging relationship between the notes and the interest rate derivative.

Income Tax Expense. Chesapeake recorded income tax expense of $289.8 million in 2004 compared to income tax expense of $191.8 million in 2003 and $26.9 million in 2002. Our effective income tax rate decreased to 36% in 2004 compared to 38% in 2003 and 40% in 2002. The decrease in 2004 and 2003 reflected the impact state income taxes and permanent differences had on our overall effective rate. Our effective income tax rate will increase to 36.5% in 2005 to reflect our current assessment of the impact state income taxes and permanent differences will have on our overall effective rate. During 2003 and 2001, we determined that it was more likely than not that $4.4 million and $2.4 million, respectively, of the deferred tax assets related to Louisiana net operating losses would not be realized and we recorded a valuation allowance equal to such amounts during those years. In 2004, we acquired Louisiana oil and gas properties which resulted in us determining that it was more likely than not that the $6.8 million of deferred tax assets related to Louisiana net operating losses would be realized. Therefore, the $6.8 million valuation allowance was reversed at December 31, 2004 as part of the recording of the purchase of these assets. All 2004 income tax expense was deferred, and we expect most, if not all, of our 2005 and 2006 income tax expense to be deferred.

Cumulative Effect of Accounting Change. Effective January 1, 2003, Chesapeake adopted SFAS No. 143, *Accounting For Asset Retirement Obligations*. Upon adoption of SFAS 143 in 2003, we recorded the discounted fair value of our expected future obligations of $30.5 million, a cumulative effect of the change in accounting principle, as an increase to earnings of $2.4 million (net of income taxes) and an increase in net oil and gas properties of $34.3 million.

Loss on Conversion/Exchange of Preferred Stock. Loss on conversion/exchange of preferred stock was $36.7 million in 2004. This loss was the result of a private exchange of $30.0 million of our 6.0% cumulative convertible preferred stock for 3.2 million shares of common stock and a public exchange of $194.8 million of our 6.0% cumulative convertible preferred stock for 20.8 million shares of common stock. The loss on the exchanges represented the excess of the fair value of the common stock issued over the fair value of the securities issuable pursuant to the original conversion terms. We also incurred $1.2 million in transaction costs related to the public exchange.

Application of Critical Accounting Policies

Readers of this report and users of the information contained in it should be aware of how certain events may impact our financial results based on the accounting policies in place. The four policies we consider to be the most significant are discussed below. The company's management has discussed each critical accounting policy with the audit committee of the company's board of directors.

The selection and application of accounting policies is an important process that changes as our business changes and as accounting rules are developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules and the use of judgment to the specific set of circumstances existing in our business.

Hedging. Chesapeake uses commodity price and financial risk management instruments to mitigate our exposure to price fluctuations in oil and natural gas and interest rates. Recognized gains and losses on derivative contracts are reported as a component of the related transaction. Results of oil and gas derivative transactions are reflected in oil and gas sales, and results of interest rate hedging transactions are reflected in interest expense. The changes in the fair value of derivative instruments not qualifying for designation as either cash flow or fair value hedges that occur prior to maturity are reported currently in the consolidated statement of operations as unrealized gains (losses) within oil and gas sales or interest expense. Cash flows from derivative instruments are classified in the same category within the statement of cash flows as the items being hedged, or on a basis consistent with the nature of the instruments.

Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the consolidated balance sheet as assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Any change in the fair value resulting from ineffectiveness, as defined by SFAS 133, is recognized immediately in oil and gas sales. For derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value, as well as the offsetting changes in the estimated fair value of the hedged item attributable to the hedged risk, are recognized currently in earnings. Differences between the changes in the fair values of the hedged item and the derivative instrument, if any, represent gains or losses on ineffectiveness and are reflected currently in interest expense. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Changes in fair value of contracts that do not qualify as hedges or are not designated as hedges are also recognized currently in earnings. See "Hedging Activities" above and "Item 7A—Quantitative and Qualitative Disclosures about Market Risk" for additional information regarding our hedging activities.

One of the primary factors that can have an impact on our results of operations is the method used to value our derivatives. We have established the fair value of all derivative instruments using estimates determined by our counterparties and subsequently evaluated internally using established index prices and other sources. These values are based upon, among other things, futures prices, volatility, time to maturity and credit risk. The values we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Another factor that can impact our results of operations each period is our ability to estimate the level of correlation between future changes in the fair value of the hedge instruments and the transactions being hedged, both at the inception and on an ongoing basis. This correlation is complicated since energy commodity prices, the primary risk we hedge, have quality and location differences that can be difficult to hedge effectively. The factors underlying our estimates of fair value and our assessment of correlation of our hedging derivatives are impacted by actual results and changes in conditions that affect these factors, many of which are beyond our control.

Due to the volatility of oil and natural gas prices and, to a lesser extent, interest rates, the company's financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2004, 2003 and 2002, the net market value of our derivatives was an asset of $2.5 million, a liability of $75.4 million and a liability of $44.7 million, respectively. With respect to our derivatives held as of December 31, 2004, an increase or decrease in natural gas prices of $0.10 per mmbtu would decrease or increase the estimated fair value of our derivatives by approximately $21 million. An increase or decrease in crude oil prices of $1.00 per barrel would decrease or increase the estimated fair value of our derivatives by approximately $2 million.

Oil and Gas Properties. The accounting for our business is subject to special accounting rules that are unique to the oil and gas industry. There are two allowable methods of accounting for oil and gas business activities: the successful efforts method and the full-cost method. Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion, amortization and impairment of oil and gas properties are generally calculated on a well by well or lease or field basis versus the aggregated "full cost" pool basis. Additionally, gain or loss is generally recognized on all sales of oil and gas properties under the successful efforts method. As a result, our financial statements will differ from companies that apply the successful efforts method since we will generally reflect a higher level of capitalized costs as well as a higher oil and gas depreciation, depletion and amortization rate.

Capitalized costs are amortized on a composite unit-of-production method based on proved oil and gas reserves. Depreciation, depletion and amortization expense is also based on the amount of estimated reserves. If we maintain the same level of production year over year, the depreciation, depletion and amortization expense may be significantly different if our estimate of remaining reserves changes significantly.

Proceeds from the sale of properties are accounted for as reductions of capitalized costs unless such sales involve a significant change in the relationship between costs and the value of proved reserves or the underlying value of unproved properties, in which case a gain or loss is recognized. No income is recognized in connection with contractual services provided by Chesapeake on properties in which we hold an economic interest.

The costs of unproved properties are excluded from amortization until the properties are evaluated. We review all of our unevaluated properties quarterly to determine whether or not and to what extent proved reserves have been assigned to the properties, and otherwise if impairment has occurred. Unevaluated properties are grouped by major producing area where individual property costs are not significant and are assessed individually when individual costs are significant.

We review the carrying value of our oil and gas properties under the full-cost accounting rules of the Securities and Exchange Commission on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. The two primary factors impacting this test are reserve levels and current prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of natural gas and oil reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues.

The process of estimating natural gas and oil reserves is very complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various properties increases the likelihood of significant changes in these estimates.

As of December 31, 2004, approximately 76% of our present value (discounted at 10%) of estimated future net revenues of proved reserves was evaluated by independent petroleum engineers, with the balance evaluated by our internal reservoir engineers. In addition, our internal engineers reevaluate our reserves on a quarterly basis. All reserve estimates are prepared based upon a review of production histories and other geologic, economic, ownership and engineering data we developed. The present value of estimated future net revenue shown is not intended to represent the current market value of the estimated oil and gas reserves we own. Additional information about our 2004 year-end reserve evaluation is included under "Oil and Gas Reserves" in Item 1—Properties.

In addition, the prices of natural gas and oil are volatile and change from period to period. Price changes directly impact the estimated revenues from our properties and the associated present value of future net revenues. Such changes also impact the economic life of our properties and thereby affect the quantity of reserves that can be assigned to a property.

The volatility of oil and natural gas prices and the impact of revisions to reserve estimates can have a significant impact on the company's financial condition and results of operations. Our oil and gas depreciation, depletion and amortization rates have fluctuated between $1.22 per mcfe in 2002 to $1.61 per mcfe in 2004 reflecting the impact of changes in prices and finding costs during these periods. As of December 31, 2004, a decrease in natural gas prices of $0.10 per mcf and a decrease in oil prices of $1.00 per barrel would reduce the company's estimated proved reserves by 3.4 bcfe and by 0.7 bcfe, respectively, and would also reduce the company's present value of estimated future net revenues by approximately $215 million and $40 million, respectively.

Income Taxes. As part of the process of preparing the consolidated financial statements, we are required to estimate the federal and state income taxes in each of the jurisdictions in which Chesapeake operates. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as derivative instruments, depreciation, depletion and amortization, and certain accrued liabilities for tax and accounting purposes. These differences and the net operating loss carryforwards result in deferred tax assets and liabilities, which are included in our consolidated balance sheet. We must then assess, using all available positive and negative evidence, the likelihood that the deferred tax assets will be recovered from future taxable income. If we believe that recovery is not likely, we must establish a valuation allowance. Generally, to the extent Chesapeake establishes a valuation allowance or increases or decreases this allowance in a period, we must include an expense or reduction of expense within the tax provisions in the consolidated statement of operations.

Under Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes*, an enterprise must use judgment in considering the relative impact of negative and positive evidence. The weight given to the potential effect of negative and positive evidence should be commensurate with the extent to which it can be objectively verified. The more negative evidence that exists (a) the more positive evidence is necessary and (b) the more difficult it is to support a conclusion that a valuation allowance is not needed for some portion or all of the deferred tax asset. Among the more significant types of evidence that we consider are:

- taxable income projections in future years,
- whether the carryforward period is so brief that it would limit realization of tax benefits,
- future sales and operating cost projections that will produce more than enough taxable income to realize the deferred tax asset based on existing sales prices and cost structures, and
- our earnings history exclusive of the loss that created the future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition.

If (a) natural gas and oil prices were to decrease significantly below present levels (and if such decreases were considered other than temporary), (b) exploration, drilling and operating costs were to increase significantly beyond current levels, or (c) we were confronted with any other significantly negative evidence pertaining to our ability to realize our NOL carryforwards prior to their expiration, we may be required to provide a valuation allowance against our deferred tax asset. As of December 31, 2004, we had deferred tax assets of $240.8 million.

Accounting for Business Combinations. Our business has grown substantially through acquisitions and our business strategy is to continue to pursue acquisitions as opportunities arise. We have accounted for all of our business combinations using the purchase method, which is the only method permitted under SFAS 141. Prior to the issuance of SFAS 141, *Accounting for Business Combinations* in 2001, we applied the guidance provided by Accounting Principles Board Opinion (APB) No. 16, and its interpretations, as well as various other authoritative literature and interpretations that address issues encountered in accounting for business combinations. The accounting for business combinations is complicated and involves the use of significant judgment.

Under the purchase method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given, whether in the form of cash, assets, stock or the assumption of liabilities. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess of the cost of an acquired entity, if any, over the net of the amounts assigned to assets acquired and liabilities assumed is recognized as goodwill. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if any, is allocated as a pro rata reduction of the amounts that otherwise would have been assigned to certain acquired assets.

Determining the fair values of the assets and liabilities acquired involves the use of judgment, since some of the assets and liabilities acquired do not have fair values that are readily determinable. Different techniques may be used to determine fair values, including market prices, where available, appraisals, comparisons to transactions for similar assets and liabilities and present value of estimated future cash flows, among others. Since these estimates involve the use of significant judgment, they can change as new information becomes available.

Each of the business combinations completed during the past five years were of small-to-medium sized exploration and production companies with oil and gas interests. We believe that the consideration we have paid to acquire these companies has represented the fair value of the assets and liabilities acquired at the time of acquisition. Consequently, we have not recognized any goodwill from any of our business combinations, nor do we expect to recognize any goodwill from similar business combinations that we may complete in the future.

Disclosures About Effects of Transactions with Related Parties

As of December 31, 2004, we had accrued accounts receivable from our CEO and COO of $4.2 million and $4.0 million, respectively, representing joint interest billings from December 2004 which were invoiced and paid in January 2005. Since Chesapeake was founded in 1989, our chief executive officer and chief operating officer have acquired small working interests in certain of our oil and gas properties by participating in our drilling activities. Joint interest billings to the CEO and COO are settled in cash immediately upon delivery of a monthly joint interest billing.

Under their employment agreements, the CEO and COO are permitted to participate in all or none of the wells drilled by or on behalf of Chesapeake during each calendar quarter, but they are not allowed to participate only in selected wells. A participation election is required to be received by the Compensation Committee of Chesapeake's Board of Directors 30 days prior to the start of a quarter. Their participation is permitted only under the terms outlined in their employment agreements, which, among other things, limit their individual participation to a maximum working interest of 2.5% in a well and prohibits participation in situations where Chesapeake's working interest would be reduced below 12.5% as a result of their participation. In addition, the company is reimbursed for the cost of its leasehold acquired by the CEO and COO as a result of their well participation.

As disclosed in Item 8—Financial Statements and Supplementary Data—Note 8, in 2004, Chesapeake had revenues of $467.4 million from oil and gas sales to an affiliated entity.

During 2004, 2003 and 2002, we paid legal fees of $1.1 million, $2.1 million and $0.6 million, respectively, for legal services provided by a law firm of which a director is a member.

Recently Issued Accounting Standards

During 2004, the Financial Accounting Standards Board and the Securities and Exchange Commission issued the following standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

In September 2004, the FASB finalized FASB Staff Position, FSP SFAS 142-2, *Application of FASB Statement No. 142 to Oil and Gas Producing Entities.* The FSP clarified that an exception in SFAS 142 includes the balance sheet classification and disclosures for drilling and mineral rights of oil and gas producing entities. The FASB staff acknowledged that the existing accounting framework for oil and gas producers is based on the level of established reserves, not whether an asset is tangible. The FSP confirms Chesapeake's historical treatment of these costs.

In September 2004, the Securities and Exchange Commission issued Staff Accounting Bulletin 106 which summarizes the views of the staff regarding the application of SFAS 143, *Accounting for Asset Retirement Obligations*, by oil and gas producing companies following the full cost accounting method. SAB 106 was effective in the fourth quarter of 2004. Implementation of this bulletin did not have a material effect on our financial statements.

In September 2004, the Emerging Issues Task Force issued EITF No. 04-8, *The Effect of Contingently Convertible Instruments on Diluted Earnings per Share.* EITF No. 04-8 provides new guidance on when the dilutive effect of contingently convertible securities with a market price trigger should be included in diluted EPS. The guidance in EITF No. 04-8 is effective for all periods ending after December 15, 2004 and Chesapeake has complied by retrospectively restating previous reported EPS. The effect of this pronouncement on diluted EPS is more fully described in note 1 to the notes to our consolidated financial statements included in Item 8.

In December 2004, the Financial Accounting Standards Board issued SFAS 123(R), *Share-Based Payment*, a revision of SFAS 123, accounting for stock-based compensation. This statement establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services by requiring a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. That cost will be recognized over the period during which an employee is required to provide service in exchange for the award. The fair value of employee stock options will be estimated using option-pricing models. Excess tax benefits will be recognized as an addition to paid-in capital. Cash retained as a result of those excess tax benefits will be presented in the statement of cash flows as financing cash inflows. The write-off of deferred tax assets relating to unrealized tax benefits associated with recognized compensation cost will be recognized as income tax expense unless there are excess tax benefits from previous awards remaining in paid-in capital to which it can be offset. This statement is effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005.

Forward-Looking Statements

This report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements give our current expectations or forecasts of future events. They include statements regarding oil and gas reserve estimates, planned capital expenditures, the drilling of oil and gas wells and future acquisitions, expected oil and gas production, cash flow and anticipated liquidity, business strategy and other plans and objectives for future operations, expected future expenses and utilization of net operating loss carryforwards. Statements concerning the fair values of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility.

Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in Item 1 and include:

- the volatility of oil and gas prices,
- our level of indebtedness,
- the strength and financial resources of our competitors,
- the availability of capital on an economic basis to fund reserve replacement costs,
- uncertainties inherent in estimating quantities of oil and gas reserves, projecting future rates of production and the timing of development expenditures,
- our ability to replace reserves and sustain production,
- uncertainties in evaluating oil and gas reserves of acquired properties and associated potential liabilities,
- unsuccessful exploration and development drilling,
- declines in the values of our oil and gas properties resulting in ceiling test write-downs,
- lower prices realized on oil and gas sales and collateral required to secure hedging liabilities resulting from our commodity price risk management activities, and
- drilling and operating risks.

We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this report, and we undertake no obligation to update this information. We urge you to carefully review and consider the disclosures made in this and our other reports filed with the Securities and Exchange Commission that attempt to advise interested parties of the risks and factors that may affect our business.

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

Oil and Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of December 31, 2004, our oil and gas derivative instruments were comprised of swaps, cap-swaps, basis protection swaps, call options and collars. These instruments allow us to predict with greater certainty the effective oil and gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

- For swap instruments, Chesapeake receives a fixed price for the hedged commodity and pays a floating market price, as defined in each instrument, to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.
- For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a “cap” limiting the counterparty’s exposure. In other words, there is no limit to Chesapeake’s exposure but there is a limit to the downside exposure of the counterparty. Because this derivative includes a written put option (i.e., the cap), cap-swaps do not qualify for designation as cash flow hedges (in accordance with SFAS 133) since the combination of the hedged item and the written put option do not provide as much potential for favorable cash flows as exposure to unfavorable cash flows.
- Basis protection swaps are arrangements that guarantee a price differential of oil or gas from a specified delivery point. Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.
- For call options, Chesapeake receives a cash premium from the counterparty in exchange for the sale of a call option. If the market price exceeds the fixed price of the call option, then Chesapeake pays the counterparty such excess. If the market price settles below the fixed price of the call option, no payment is due from Chesapeake.
- Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.

Chesapeake enters into counter-swaps from time to time for the purpose of locking in the value of a swap. Under the counter-swap, Chesapeake receives a floating price for the hedged commodity and pays a fixed price to the counterparty. The counter-swap is 100% effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap. We refer to this locked-in value as a locked swap. At the time Chesapeake enters into a counter-swap, Chesapeake removes the original swap’s designation as a cash flow hedge and classifies the original swap as a non-qualifying hedge under SFAS 133. The reason for this new designation is that collectively the swap and the counter-swap no longer hedge the exposure to variability in expected future cash flows. Instead, the swap and counter-swap effectively lock in a specific gain (or loss) that will be unaffected by subsequent variability in oil and gas prices. Any locked in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and gas sales in the month of related production.

With respect to counter-swaps that are designed to lock in the value of cap-swaps, the counter-swap is effective in locking in the value of the cap-swap until the floating price reaches the cap (or floor) stipulated in the cap-swap agreement. The value of the counter-swap will increase (or decrease), but in the opposite direction, as the value of the cap-swap decreases (or increases) until the floating price reaches the pre-determined cap (or floor) stipulated in the cap-swap agreement. However, because of the written put option embedded in the cap-swap, the changes in value of the cap-swap are not completely effective in offsetting changes in value of the corresponding counter-swap. Changes in the value of cap-swaps and the counter-swaps are recorded as adjustments to oil and gas sales.

In accordance with FASB Interpretation No. 39, Chesapeake nets the value of its derivative arrangements with the same counterparty in the accompanying consolidated balance sheets, to the extent that a legal right of setoff exists.

Chesapeake enters into basis protection swaps for the purpose of locking in a price differential of oil or gas for a specified delivery point. We currently have basis protection swaps covering four different delivery points which correspond to the actual price we receive for much of our gas production. By entering into these basis protection swaps, we have effectively reduced our exposure to market changes in future gas price differentials. As of December 31, 2004, the fair value of our basis protection swaps was $122.3 million. As of December 31, 2004, our basis protection swaps cover 48% of our anticipated gas production in 2005, 30% in 2006, 27% in 2007, 24% in 2008 and 17% in 2009.

Gains or losses from derivative transactions are reflected as adjustments to oil and gas sales on the consolidated statements of operations. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within oil and gas sales. Unrealized gains (losses) included in oil and gas sales in 2004, 2003 and 2002 were $40.9 million, $10.5 million and ($87.3) million, respectively.

Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and gas sales as unrealized gains (losses). We recorded a gain (loss) on ineffectiveness of ($8.2) million, ($9.2) million and ($3.6) million in 2004, 2003 and 2002, respectively.

As of December 31, 2004, we had the following open oil and gas derivative instruments designed to hedge a portion of our oil and gas production for periods after December 2004:

	Volume	Weighted-Average Fixed Price to be Received (Paid)	Weighted-Average Put Fixed Price	Weighted-Average Call Fixed Price	Weighted-Average Differential	SFAS 133 Hedge	Premiums Received	Fair Value at December 31, 2004 ($ in thousands)
Natural Gas (mmbtu):								
Swaps:								
2005	95,355,000	$ 6.72	$ —	$ —	$ —	Yes	$ —	$ 50,303
2006	18,250,000	6.60	—	—	—	Yes	—	6,770
Basis Protection Swaps:								
2005	188,590,000	—	—	—	(0.26)	No	—	43,270
2006	130,140,000	—	—	—	(0.32)	No	—	20,704
2007	126,495,000	—	—	—	(0.28)	No	—	24,433
2008	118,610,000	—	—	—	(0.27)	No	—	21,399
2009	86,600,000	—	—	—	(0.29)	No	—	12,481
Cap-Swaps:								
2005	60,225,000	6.00	4.32	—	—	No	—	(35,422)
2006	28,350,000	6.52	4.93	—	—	No	—	(13,339)
Counter Swaps:								
2006	(7,300,000)	(5.59)	—	—	—	No	—	4,654
Call Options:								
2005	7,300,000	—	—	6.00	—	No	3,249	(5,793)
Collars:								
2005	4,380,000	—	3.10	4.44	—	Yes	—	(5,573)
Locked Swaps:								
2005	38,870,000	—	—	—	—	No	—	(43,072)
2006	25,550,000	—	—	—	—	No	—	(22,601)
2007	25,550,000	—	—	—	—	No	—	(11,626)
Total Natural Gas							3,249	46,588
Oil (bbls):								
Cap-Swaps:								
2005	1,995,500	$40.20	$31.44	$ —	$ —	No	$ —	$ (8,238)
Total Oil							—	(8,238)
Total Natural Gas and Oil							$3,249	$ 38,350

We have established the fair value of all derivative instruments using estimates of fair value reported by our counterparties and subsequently evaluated internally using established index prices and other sources. The actual contribution to our future results of operations will be based on the market prices at the time of settlement and may be more or less than the fair value estimates used at December 31, 2004.

Based upon the market prices at December 31, 2004, we expect to transfer approximately $7.3 million of income included in the balance in accumulated other comprehensive income to earnings during the next 12 months when the transactions actually occur. All transactions hedged as of December 31, 2004 are expected to mature by December 31, 2007, with the exception of our basis protection swaps which extend through 2009.

Additional information concerning the fair value of our oil and gas derivative instruments is as follows:

	December 31, 2004	2003	2002
	($ in thousands)		
Fair value of contracts outstanding, as of January 1	$ (44,988)	$(14,533)	$157,309
Change in fair value of contracts during the period	(69,927)	(31,078)	(52,419)
Contracts realized or otherwise settled during the period	154,901	17,389	(96,046)
Fair value of new contracts when entered into during the period	(5,369)	(16,766)	(45,603)
Fair value of contracts when closed during the period	3,733	—	22,226
Fair value of contracts outstanding, as of December 31	$ 38,350	$(44,988)	$ (14,533)

The change in the fair value of our derivative instruments since January 1, 2004 resulted mainly from the settlement of derivatives for a realized loss. Derivative instruments reflected as current in the consolidated balance sheet represent the estimated fair value of derivative instrument settlements scheduled to occur over the subsequent twelve-month period based on market prices for oil and gas as of the consolidated balance sheet date. The derivative settlement amounts are not due and payable until the month in which the related underlying hedged transaction occurs.

Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates. As of December 31, 2004, the fair value of the fixed-rate long-term debt has been estimated based on quoted market prices.

	Years of Maturity 2005	2006	2007	2008	2009	Thereafter	Total	Fair Value
	($ in millions)							
Liabilities:								
Long-term debt—fixed rate (1)	$—	$—	$—	$19.0	$—	$3,080.1	$3,099.1	$3,281.1
Average interest rate	—	—	—	8.4%	—	7.3%	7.3%	7.3%
Long-term debt—variable-rate	$—	$—	$—	$ —	$—	$ 59.0	$ 59.0	$ 59.0
Average interest rate	—	—	—	—	—	5.3%	5.3%	5.3%

(1) This amount does not include the discount included in long-term debt of ($84.9) million and the premium for interest rate swaps of $2.0 million.

Changes in interest rates affect the amount of interest we earn on our cash, cash equivalents and short-term investments and the interest rate we pay on borrowings under our revolving bank credit facility. All of our other long-term indebtedness is fixed rate and therefore does not expose us to the risk of earnings or cash flow loss due to changes in market interest rates. However, changes in interest rates do affect the fair value of our debt.

Interest Rate Derivatives

We utilize hedging strategies to manage our exposure to changes in interest rates. To the extent interest rate swaps have been designated as fair value hedges, changes in the fair value of the derivative instrument and the corresponding debt are reflected as adjustments to interest expense in the corresponding months covered by the derivative agreement. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

As of December 31, 2004, the following interest rate swaps to convert a portion of our long-term fixed rate debt to floating rate debt were outstanding:

Term	Notional Amount	Fixed Rate	Floating Rate	Fair Value as of December 31, 2004
				($ in thousands)
November 2004 – June 2014	$75,000,000	7.500%	6-month LIBOR in arrears plus 254 basis points	$(333)
November 2004 – January 2015	$75,000,000	7.750%	6-month LIBOR in arrears plus 291 basis points	$(914)
September 2004 – August 2012	$75,000,000	9.000%	6-month LIBOR plus 452 basis points	$(269)

During 2004, we entered into and subsequently closed five separate interest rate swaps for a total gain of $3.8 million. These interest rate swaps were designated as fair value hedges of the related senior notes. The settlement amounts received will be amortized as a reduction to realized interest expense over the remaining terms of the related senior notes. The senior notes hedged mature in 2014 and 2015.

In 2005, we closed the 7.5% and 7.75% interest rate swaps for gains totaling $0.8 million. These interest rate swaps were designated as fair value hedges of the related senior notes. The settlement amounts received will be amortized as a reduction to realized interest expense over the remaining terms of the senior notes. The senior notes hedged mature in 2014 and 2015.

In March 2004, Chesapeake entered into an interest rate swap which requires Chesapeake to pay a fixed rate of 8.68% while the counterparty pays Chesapeake a floating rate of six month LIBOR plus 0.75% on a notional amount of $142.7 million. The counterparty may elect to terminate the swap and cause it to be settled at the then current estimated fair value of the interest rate swap on March 15, 2005 and annually thereafter until March 15, 2011. The interest rate swap expires on March 15, 2012. Chesapeake may elect to terminate the swap and cause it to be settled at the then current estimated fair value of the interest rate swap at any time during the term of the swap.

As of December 31, 2004, the fair value of the interest rate swap was a liability of $34.3 million. Because the interest rate swap is not designated as a fair value hedge, changes in the fair value of the swap are recorded as adjustments to interest expense. In 2004, interest expense related to the swap includes an unrealized loss of $4.2 million and a realized loss of $2.2 million.

In January 2004, Chesapeake acquired a $50 million interest rate swap as part of the purchase of Concho Resources Inc. Under the terms of the interest rate swap, the counterparty pays Chesapeake a floating three-month LIBOR rate and Chesapeake pays a fixed rate of 2.875%. Payments are made quarterly and the interest rate swap extends through September 2005. An initial liability of $0.6 million was recorded based on the fair value of the interest rate swap at the time of acquisition. As of December 31, 2004, the interest rate swap had a negligible fair value. Because this instrument is not designated as a fair value hedge, an unrealized gain of $0.1 million was recognized in 2004 as part of interest expense.

ITEM 8. ***Financial Statements and Supplementary Data***

INDEX TO FINANCIAL STATEMENTS

CHESAPEAKE ENERGY CORPORATION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

It is the responsibility of the management of Chesapeake Energy Corporation (the "Company") to establish and maintain effective internal control over financial reporting (as defined in Rule 13a–15(f) under the Securities Exchange Act of 1934). Management utilized the Committee of Sponsoring Organizations of the Treadway Commission's *Internal Control—Integrated Framework* (COSO framework) in conducting the required assessment of effectiveness of the Company's internal control over financial reporting.

Management has performed an assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004 and has determined the Company's internal control over financial reporting was effective.

Our management's assessment of the effectiveness of the Company's internal control over financial reporting as of March 7, 2005 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Aubrey K. McClendon
Chairman and Chief Executive Officer

Marcus C. Rowland
Executive Vice President and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
of Chesapeake Energy Corporation:

We have completed an integrated audit of Chesapeake Energy Corporation's 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedule

In our opinion, the consolidated financial statements listed in the accompanying index appearing under Item 8 of the Form 10-K present fairly, in all material respects, the financial position of Chesapeake Energy Corporation and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their 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. In addition, in our opinion, the financial statement schedule also listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements 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 of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 12 to the consolidated financial statements, effective January 1, 2003, the Company changed the manner in which it accounts for asset retirement obligations.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting appearing under Item 8, that 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), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by the 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 opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting 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. An audit of internal control over financial reporting includes 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 consider 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 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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

PricewaterhouseCoopers LLP
Oklahoma City, Oklahoma

March 7, 2005

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2004	December 31, 2003
	($ in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 6,896	$ 40,581
Accounts receivable:		
Oil and gas sales	347,081	173,792
Joint interest, net of allowances of $4,648,000 and $2,669,000, respectively	68,220	37,789
Related parties	8,286	2,983
Other	35,781	26,830
Deferred income tax asset	18,068	36,705
Short-term derivative instruments	51,061	4,467
Inventory and other	32,147	19,257
Total Current Assets	567,540	342,404
PROPERTY AND EQUIPMENT:		
Oil and gas properties, at cost based on full-cost accounting:		
Evaluated oil and gas properties	9,451,413	6,221,576
Unevaluated properties	761,785	227,331
Less: accumulated depreciation, depletion and amortization of oil and gas properties	(3,057,742)	(2,480,261)
Total oil and gas properties, at cost based on full-cost accounting	7,155,456	3,968,646
Other property and equipment	373,870	225,891
Less: accumulated depreciation and amortization of other property and equipment	(84,942)	(61,420)
Total Property and Equipment	7,444,384	4,133,117
OTHER ASSETS:		
Long-term derivative instruments	44,169	17,493
Investments	92,743	31,544
Other assets	95,673	47,733
Total Other Assets	232,585	96,770
TOTAL ASSETS	$ 8,244,509	$ 4,572,291
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 367,176	$ 164,264
Accrued interest	66,514	46,648
Short-term derivative instruments	91,414	92,651
Other accrued liabilities	222,029	108,020
Revenues and royalties due others	216,820	101,573
Total Current Liabilities	963,953	513,156
LONG-TERM LIABILITIES:		
Long-term debt, net	3,075,109	2,057,713
Revenues and royalties due others	17,007	13,921
Asset retirement obligation	73,718	48,812
Long-term derivative instruments	1,296	4,736
Deferred income tax liability	933,873	191,026
Other liabilities	16,670	10,117
Total Long-term Liabilities	4,117,673	2,326,325
CONTINGENCIES AND COMMITMENTS (Note 4)		
STOCKHOLDERS' EQUITY:		
Preferred Stock, $.01 par value, 20,000,000 and 10,000,000 shares authorized at December 31, 2004 and 2003, respectively:		
6.75% cumulative convertible preferred stock, zero and 2,998,000 shares issued and outstanding at December 31, 2004 and 2003, respectively, entitled in liquidation to $0 and $149,900,000	—	149,900
6.00% cumulative convertible preferred stock, 103,110 and 4,600,000 shares issued and outstanding at December 31, 2004 and 2003, respectively, entitled in liquidation to $5,155,500 and $230,000,000	5,156	230,000
5.00% cumulative convertible preferred stock, 1,725,000 shares issued and outstanding at December 31, 2004 and 2003, entitled in liquidation to $172,500,000	172,500	172,500
4.125% cumulative convertible preferred stock, 313,250 and zero shares issued and outstanding at December 31, 2004 and 2003, respectively, entitled in liquidation to $313,250,000	313,250	—
Common Stock, $.01 par value, 500,000,000 and 350,000,000 shares authorized, 316,940,784 and 221,855,894 shares issued at December 31, 2004 and 2003, respectively	3,169	2,218
Paid-in capital	2,440,105	1,389,212
Retained earnings (deficit)	262,987	(168,617)
Accumulated other comprehensive income (loss), net of tax of ($11,489,000) and $12,449,000, respectively	20,425	(20,312)
Unearned compensation	(32,618)	—
Less: treasury stock, at cost; 5,072,121 and 5,071,571 common shares at December 31, 2004 and 2003, respectively	(22,091)	(22,091)
Total Stockholders' Equity	3,162,883	1,732,810
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 8,244,509	$ 4,572,291

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2004	2003	2002
	(in thousands, except per share data)		
REVENUES:			
Oil and gas sales	$1,936,176	$1,296,822	$ 568,187
Oil and gas marketing sales	773,092	420,610	170,315
Total Revenues	2,709,268	1,717,432	738,502
OPERATING COSTS:			
Production expenses	204,821	137,583	98,191
Production taxes	103,931	77,893	30,101
General and administrative expenses:			
General and administrative (excluding stock-based compensation)	32,217	22,808	17,262
Stock-based compensation	4,828	945	356
Oil and gas marketing expenses	755,314	410,288	165,736
Oil and gas depreciation, depletion and amortization	582,137	369,465	221,189
Depreciation and amortization of other assets	29,185	16,793	14,009
Provision for legal settlements	4,500	6,402	—
Total Operating Costs	1,716,933	1,042,177	546,844
INCOME FROM OPERATIONS	992,335	675,255	191,658
OTHER INCOME (EXPENSE):			
Interest and other income	4,476	2,827	7,340
Interest expense	(167,328)	(154,356)	(112,031)
Loss on repurchases or exchanges of Chesapeake debt	(24,557)	(20,759)	(2,626)
Loss on investment in Seven Seas	—	(2,015)	(17,201)
Total Other Income (Expense)	(187,409)	(174,303)	(124,518)
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	804,926	500,952	67,140
INCOME TAX EXPENSE:			
Current	—	5,000	(1,822)
Deferred	289,771	185,360	28,676
Total Income Tax Expense	289,771	190,360	26,854
NET INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	515,155	310,592	40,286
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, NET OF INCOME TAXES OF $1,464,000	—	2,389	—
NET INCOME	515,155	312,981	40,286
PREFERRED STOCK DIVIDENDS	(39,506)	(22,469)	(10,117)
LOSS ON CONVERSION/EXCHANGE OF PREFERRED STOCK	(36,678)	—	—
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 438,971	$ 290,512	$ 30,169
EARNINGS PER COMMON SHARE – BASIC:			
Income before cumulative effect of accounting change	$ 1.73	$ 1.36	$ 0.18
Cumulative effect of accounting change	—	0.02	—
	$ 1.73	$ 1.38	$ 0.18
EARNINGS PER COMMON SHARE – ASSUMING DILUTION:			
Income before cumulative effect of accounting change	$ 1.53	$ 1.20	$ 0.17
Cumulative effect of accounting change	—	0.01	—
	$ 1.53	$ 1.21	$ 0.17
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.170	$ 0.135	$ 0.060
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in thousands):			
Basic	253,212	211,203	166,910
Assuming dilution	305,718	258,567	172,714

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2004	2003	2002
	($ in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME	$ 515,155	$ 312,981	$ 40,286
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion and amortization	605,593	382,004	230,236
Deferred income taxes	289,532	186,664	28,676
Loss on repurchases or exchanges of Chesapeake debt	24,557	20,759	2,626
Amortization of loan costs and bond discount	10,275	5,861	6,041
Unrealized (gains) losses on derivatives	(35,549)	(3,992)	88,018
Stock-based compensation	4,828	—	—
Cumulative effect of accounting change	—	(3,853)	—
Loss on investment in Seven Seas	—	2,015	17,201
Other	4,412	1,490	(567)
Cash provided by operating activities before changes in assets and liabilities	1,418,803	903,929	412,517
CHANGES IN ASSETS AND LIABILITIES:			
(Increase) decrease in accounts receivable	(152,590)	(72,683)	(44,966)
(Increase) decrease in inventory and other assets	(9,481)	(10,971)	11,330
Increase (decrease) in accounts payable, accrued liabilities and other	97,635	86,861	23,223
Increase (decrease) in current and non-current revenues and royalties due others	94,188	38,466	30,427
Change in assets and liabilities	29,752	41,673	20,014
Cash provided by operating activities	1,448,555	945,602	432,531
CASH FLOWS FROM INVESTING ACTIVITIES:			
Acquisitions of oil and gas companies, proved properties and unproved properties, net of cash acquired	(1,914,746)	(1,261,275)	(331,651)
Exploration and development of oil and gas properties	(1,276,341)	(727,231)	(400,180)
Additions to buildings and other fixed assets	(126,707)	(71,454)	(33,559)
Additions to investments	(36,962)	(30,750)	(2,408)
Additions to drilling rig equipment	(23,093)	(1,221)	(3,551)
Deposits for acquisitions	(16,250)	(13,250)	(15,000)
Divestitures of oil and gas properties	12,048	22,156	839
Sale of non-oil and gas assets and recoveries of investments	860	5,799	5,774
Other	(13)	9	(9)
Cash used in investing activities	(3,381,204)	(2,077,217)	(779,745)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term borrowings	2,160,000	738,000	252,500
Payments on long-term borrowings	(2,101,000)	(738,000)	(252,500)
Cash received from issuance of senior notes, net of offering costs	1,165,975	485,445	439,427
Proceeds from issuance of preferred stock, net of offering costs	304,936	390,365	—
Proceeds from issuance of common stock, net of offering costs	624,187	177,427	164,104
Cash paid to purchase or exchange senior notes, including redemption premium	(264,715)	(113,074)	(111,597)
Cash paid for common stock dividends	(38,902)	(27,253)	(4,987)
Cash paid for preferred stock dividends	(40,907)	(20,916)	(10,177)
Cash paid for financing cost of credit facilities	(9,175)	(2,474)	(2,902)
Cash paid for treasury stock and preferred stock	—	(2,109)	—
Net increase in outstanding payments in excess of cash balance	88,348	28,315	—
Other financing costs	(1,770)	(496)	(421)
Cash received from exercise of stock options	11,987	9,329	3,810
Cash provided by financing activities	1,898,964	924,559	477,257
Net increase (decrease) in cash and cash equivalents	(33,685)	(207,056)	130,043
Cash and cash equivalents, beginning of period	40,581	247,637	117,594
Cash and cash equivalents, end of period	$ 6,896	$ 40,581	$ 247,637

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS—(Continued)

	Years Ended December 31,		
	2004	2003	2002
	($ in thousands)		
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:			
Interest, net of capitalized interest	$134,000	$137,146	$105,671
Income taxes, net of refunds received	$ 239	$ 5,160	$ (738)

SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:

In 2004, we completed a public exchange offer in which we retired $458.5 million of our 8.125% Senior Notes due 2011 and $10.8 million of accrued interest and issued $72.8 million of our 7.75% Senior Notes 2015 and $2.8 million of accrued interest and $433.5 million of our 6.875% Senior Notes due 2016 and $4.1 million of accrued interest.

In 2004, we issued an additional $37.0 million of our 6.875% Senior Notes due 2016 and $0.5 million of accrued interest in exchange for $24.3 million of our 8.125% Senior Notes due 2011 and $0.7 million of accrued interest and $9.1 million of our 7.75% Senior Notes due 2015 and $0.1 million of accrued interest in four private exchange transactions.

In 2004, holders of our 6.75% cumulative convertible preferred stock converted 2,998,000 shares into 19,467,482 shares of common stock (at a conversion price of $7.70 per share).

In 2004, holders of our 6.0% cumulative convertible preferred stock exchanged 600,000 shares for 3,225,000 shares of common stock and 3,896,890 shares for 20,754,817 shares of common stock in a privately negotiated exchange and a public exchange offer, respectively.

In 2004, Chesapeake acquired Hallwood Energy Corporation for a total consideration of $292.0 million, consisting of $223.5 million of cash and short-term notes payable of $60.0 million.

In 2003, we issued $86.7 million of our 7.75% Senior Notes due 2015, $63.8 million of our 7.50% Senior Notes due 2013 and accrued interest of $1.0 million in exchange for $71.7 million of our 8.125% Senior Notes due 2011, $40.2 million of our 8.375% Senior Notes due 2008, $32.0 million of our 8.5% Senior Notes due 2012 and $2.2 million of accrued interest, pursuant to privately negotiated transactions. The $71.7 million of our 8.125% Senior Notes, $40.2 million of our 8.375% Senior Notes and $32.0 million of our 8.5% Senior Notes were retired upon receipt.

As of December 31, 2004, 2003 and 2002, dividends payable on our common and preferred stock were $19.4 million, $15.7 million and $8.2 million, respectively.

In 2004, 2003 and 2002 oil and gas properties were adjusted by $463.9 million, ($4.9) million and $62.4 million, respectively, for net tax liabilities related to acquisitions.

During 2004, 2003 and 2002, $29.7 million, $18.1 million, and $1.0 million, respectively, of additions to oil and gas properties were recorded as an increase to accrued exploration and development costs.

In January 2003, Chesapeake adopted SFAS 143, *Accounting For Asset Retirement Obligation.* As a result, we recorded non-cash additions to net oil and gas properties of $24.9 million and $48.8 million in 2004 and 2003, respectively.

In 2002, holders of our 6.75% cumulative convertible preferred stock converted 2,000 shares into 12,987 shares of common stock (at a conversion price of $7.70 per share).

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Years Ended December 31,		
	2004	2003	2002
		($ in thousands)	
PREFERRED STOCK:			
Balance, beginning of period	$ 552,400	$ 149,900	$ 150,000
Issuance of 6.00% cumulative convertible preferred stock	—	230,000	—
Issuance of 5.00% cumulative convertible preferred stock	—	172,500	—
Issuance of 4.125% cumulative convertible preferred stock	313,250	—	—
Exchange of common stock for 2,000 shares of 6.75% preferred stock	—	—	(100)
Exchange of common stock for 2,998,000 shares of 6.75% preferred stock	(149,900)	—	—
Exchange of common stock for 4,496,890 of 6.00% preferred stock	(224,844)	—	—
Balance, end of period	490,906	552,400	149,900
COMMON STOCK:			
Balance, beginning of period	2,218	1,949	1,696
Exercise of stock options and warrants	29	39	23
Issuance of 46,000,000 shares of common stock	460	—	—
Issuance of 23,000,000 shares of common stock	—	230	230
Restricted stock grants	27	—	—
Exchange of 43,447,299 shares of common stock for preferred stock	435	—	—
Balance, end of period	3,169	2,218	1,949
PAID-IN CAPITAL:			
Balance, beginning of period	1,389,212	1,205,554	1,035,156
Exercise of stock options and warrants	11,958	9,290	3,787
Issuance of common stock	649,520	186,070	172,270
Offering expenses	(34,297)	(21,139)	(8,506)
Exchange of 43,447,299 and 12,987 shares of common stock for preferred stock	374,310	—	100
Preferred stock conversion/exchange cost	(1,218)	—	—
Compensation costs related to stock and stock options	41,485	2,292	356
Tax benefit from exercise of stock options	9,135	7,145	2,391
Balance, end of period	2,440,105	1,389,212	1,205,554
RETAINED EARNINGS (DEFICIT):			
Balance, beginning of period	(168,617)	(426,085)	(442,974)
Net income	515,155	312,981	40,286
Dividends on common stock	(45,229)	(29,128)	(10,690)
Dividends on preferred stock	(38,322)	(26,385)	(12,707)
Balance, end of period	262,987	(168,617)	(426,085)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance, beginning of period	(20,312)	(3,461)	43,511
Gain (loss) on hedging activity	15,946	(16,851)	(46,972)
Unrealized gain (loss) on marketable securities	24,791	—	—
Balance, end of period	20,425	(20,312)	(3,461)
UNEARNED COMPENSATION:			
Balance, beginning of period	—	—	—
Restricted stock granted	(38,949)	—	—
Amortization of unearned compensation	6,331	—	—
Balance, end of period	(32,618)	—	—
TREASURY STOCK—COMMON:			
Balance, beginning of period	(22,091)	(19,982)	(19,982)
Purchase of 279,042 shares of treasury stock	—	(2,109)	—
Balance, end of period	(22,091)	(22,091)	(19,982)
TOTAL STOCKHOLDERS' EQUITY	$3,162,883	$1,732,810	$ 907,875

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Years Ended December 31,		
	2004	2003	2002
	($ in thousands)		
Net Income	$515,155	$312,981	$ 40,286
Other comprehensive income (loss), net of income tax:			
Change in fair value of derivative instruments, net of income taxes of $(44,463,000), $(15,272,000) and $(18,027,000)	(79,046)	(24,917)	(27,041)
Reclassification of (gain) loss on settled contracts, net of income taxes of $50,480,000, $1,448,000 and $(14,711,000)	89,743	2,363	(22,066)
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of $2,953,000, $3,495,000 and $1,423,000	5,249	5,703	2,135
Unrealized gain on marketable securities, net of income taxes of $13,945,000	24,791	—	—
Comprehensive income (loss)	$555,892	$296,130	$ (6,686)

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Summary of Significant Accounting Policies

Description of Company

Chesapeake Energy Corporation is an oil and natural gas exploration and production company engaged in the acquisition, exploration, and development of properties for the production of crude oil and natural gas from underground reservoirs and the marketing of natural gas and oil for other working interest owners in properties we operate. Our properties are located in Oklahoma, Texas, Arkansas, Louisiana, Kansas, Montana, Colorado, North Dakota and New Mexico.

Principles of Consolidation

The accompanying consolidated financial statements of Chesapeake Energy Corporation include the accounts of our direct and indirect wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated. Investments in companies and partnerships which give us significant influence, but not control, over the investee are accounted for using the equity method. Other investments are generally carried at cost.

Accounting Estimates

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

Cash Equivalents

For purposes of the consolidated financial statements, Chesapeake considers investments in all highly liquid instruments with maturities of three months or less at date of purchase to be cash equivalents.

Inventory

Inventory, which is included in current assets, consists primarily of tubular goods and other lease and well equipment which we plan to utilize in our ongoing exploration and development activities and is carried at the lower of cost or market using the specific identification method. Oil inventory in tanks is carried at the lower of the estimated cost to produce or market value.

Oil and Gas Properties

Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities (see note 11). Capitalized costs are amortized on a composite unit-of-production method based on proved oil and gas reserves. As of December 31, 2004, approximately 76% of our present value (discounted at 10%) of estimated future net revenues of proved reserves was evaluated by independent petroleum engineers, with the balance evaluated by our internal reservoir engineers. In addition, our internal engineers evaluate all properties quarterly. The average composite rates used for depreciation, depletion and amortization were $1.61 per equivalent mcfe in 2004, $1.38 per equivalent mcfe in 2003, and $1.22 per equivalent mcfe in 2002.

Proceeds from the sale of properties are accounted for as reductions of capitalized costs unless such sales involve a significant change in the relationship between costs and the value of proved reserves or the underlying value of unproved properties, in which case a gain or loss is recognized. No income is recognized in connection with contractual services provided by Chesapeake on properties in which we hold an economic interest.

The costs of unproved properties are excluded from amortization until the properties are evaluated. We review all of our unevaluated properties quarterly to determine whether or not and to what extent proved reserves have been assigned to the properties and otherwise if impairment has occurred. Unevaluated properties are grouped by major prospect area where individual property costs are not significant and are assessed individually when individual costs are significant.

We review the carrying value of our oil and gas properties under the full-cost accounting rules of the Securities and Exchange Commission on a quarterly basis. Under these rules, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects.

Other Property and Equipment

Other property and equipment consists primarily of gas gathering and processing facilities, drilling rigs, vehicles, land, office buildings, office equipment, and software. Land purchases are made in order to build additional office space at our Oklahoma City headquarters and field offices. Major renewals and betterments are capitalized while the costs of repairs and maintenance are charged to expense as incurred. The costs of assets retired or otherwise disposed of and the applicable accumulated depreciation are removed from the accounts, and the resulting gain or loss is reflected in operations. Other property and equipment costs are depreciated on a straight-line basis. A summary of other property and equipment and the useful lives are as follows:

	December 31,		
	2004	2003	Useful Life
	($ in thousands)		(in years)
Land	$ 24,153	$ 11,777	—
Buildings and improvements	105,516	74,272	15 – 39
Gathering, processing and compression equipment	112,888	56,908	7 – 15
Other fixtures and equipment	81,938	56,652	2 – 7
Drilling rigs	49,375	26,282	15
Total	$373,870	$225,891	

Investments in Securities

Investments in securities are accounted for under the equity method in circumstances where we are deemed to exercise significant influence over the operating and investing policies of the investee. Under the equity method, we recognize our share of the investee's earnings in our consolidated statements of operations. Investments in securities not accounted for under the equity method are accounted for under the cost method. Investments in marketable equity securities accounted for under the cost method have been designated as available for sale and, as such, are recorded at fair value. We have no investments which are required to be consolidated pursuant to the terms of FIN 46, *Consolidation of Variable Interest Entities.*

Included in investments at December 31, 2004 are equity securities totaling $92.7 million. At December 31, 2004, investments accounted for under the equity method totaled $13.2 million and investments accounted for under the cost method totaled $79.5 million. Included in the $79.5 million investment accounted for under the cost method is an investment in Pioneer Drilling Company (AMEX:PDC) reported at fair market value of $65.9 million. The fair market value of our investment in Pioneer Drilling Company at December 31, 2004 is based upon the closing price of the common stock ($10.09 per share).

Capitalized Interest

During 2004, 2003 and 2002, interest of approximately $36.2 million, $13.0 million and $5.0 million, respectively, was capitalized on significant investments in unproved properties that were not being currently depreciated, depleted or amortized and on which exploration activities were in progress. Interest is capitalized using the weighted average interest rate on our outstanding borrowings.

Accounts Payable and Accrued Liabilities

Included in accounts payable at December 31, 2004 and 2003, respectively, are liabilities of approximately $116.7 million and $28.3 million representing the amount by which checks issued, but not yet presented to our banks for collection, exceeded balances in applicable bank accounts. Other accrued liabilities include $61.0 million and $34.1 million of accrued drilling costs as of December 31, 2004 and 2003, respectively.

Debt Issue Costs

Included in other assets are costs associated with the issuance of our senior notes and costs associated with our revolving bank credit facility. The remaining unamortized debt issue costs at December 31, 2004 and 2003 totaled $54.4 million and $28.4 million, respectively, and are being amortized over the life of the senior notes or revolving credit facility.

Asset Retirement Obligations

Effective January 1, 2003, Chesapeake adopted SFAS No. 143, *Accounting for Asset Retirement Obligation.* This statement applies to obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets.

SFAS 143 requires that the fair value of a liability for a retirement obligation be recognized in the period in which the liability is incurred. For oil and gas properties, this is the period in which an oil or gas well is acquired or drilled. The asset retirement obligation is capitalized as part of the carrying amount of our oil and gas properties at its discounted fair value. The liability is then accreted each period until the liability is settled or the well is sold, at which time the liability is reversed.

Revenue Recognition

Oil and Natural Gas Sales. Revenue from the sale of oil and natural gas is recognized when title passes, net of royalties.

Gas Imbalances. We follow the "sales method" of accounting for our gas revenue whereby we recognize sales revenue on all gas sold to our purchasers, regardless of whether the sales are proportionate to our ownership in the property. An asset or a liability is recognized to the extent that we have an imbalance in excess of the remaining gas reserves on the underlying properties. The gas imbalance net position at December 31, 2004 and 2003 was a liability of $4.4 million and $3.3 million, respectively.

Marketing Sales. Chesapeake takes title to the natural gas it purchases from other working interest owners in operated wells and arranges for transportation and delivers the natural gas to third parties, at which time revenues are recorded. Chesapeake's results of operations related to its oil and gas marketing activities are presented on a "gross" basis, because we act as a principal rather than an agent. All significant intercompany accounts and transactions have been eliminated.

Hedging

From time to time, Chesapeake uses commodity price and financial risk management instruments to mitigate our exposure to price fluctuations in oil and natural gas transactions and interest rates. Recognized gains and losses on derivative contracts are reported as a component of the related transaction. Results of oil and gas derivative transactions are reflected in oil and gas sales and results of interest rate hedging transactions are reflected in interest expense. The changes in fair value of derivative instruments not qualifying for designation as either cash flow or fair value hedges that occur prior to maturity are reported currently in the consolidated statement of operations as unrealized gains (losses) within oil and gas sales or interest expense. Cash flows from derivative instruments are classified in the same category within the statement of cash flows as the items being hedged, or on a basis consistent with the nature of the instrument.

We have established the fair value of all derivative instruments using estimates determined by our counterparties and subsequently evaluated internally using established index prices and other sources. These values are based upon, among other things, futures prices, volatility, time to maturity and credit risk. The values we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities,* establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the consolidated balance sheet as assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Any change in the fair value resulting from ineffectiveness, as defined by SFAS 133, is recognized immediately in oil and gas sales. For derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value, as well as the offsetting changes in the estimated fair value of the hedged item attributable to the hedged risk, are recognized currently in earnings. Differences between the changes in the fair values of the hedged item and the derivative instrument, if any, represent gains or losses on ineffectiveness and are reflected currently in interest expense. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Changes in fair value of contracts that do not qualify as hedges or are not designated as hedges are also recognized currently in earnings.

Stock Options

Chesapeake has elected to follow APB No. 25, *Accounting for Stock Issued to Employees*, and related interpretations in accounting for its employee and director stock options. Under APB No. 25, compensation expense is recognized for the difference between the option exercise price and market value on the measurement date. The original issuance of stock options has not resulted in the recognition of compensation expense because the exercise price of the stock options granted under the plans has equaled the market price of the underlying stock on the date of grant. In March 2000, the Financial Accounting Standards Board issued FASB Interpretation No. 44 (FIN 44), which provided clarification regarding the application of APB No. 25. FIN 44 specifically addressed the accounting consequence of various modifications to the terms of a previously granted fixed-price stock option. Pursuant to FIN 44, we recognized stock-based compensation expense (a sub-category of general and administrative costs) in the consolidated statements of operations of $0.6 million, $0.9 million and $0.4 million in 2004, 2003, and 2002, respectively.

Pro forma information regarding net income and earnings per share is required by SFAS No. 123 and has been determined as if we had accounted for our employee and director stock options under the fair value method of the statement. The fair value for these options was estimated at the date of grant using a Black-Scholes option pricing model with the following weighted-average assumptions for 2004, 2003 and 2002, respectively: interest rates (zero-coupon U.S. government issues with a remaining life equal to the expected term of the options) ranging from 2.24% to 4.90%, dividend yields ranging from 0.0% to 1.85%, and volatility factors of the expected market price of our common stock ranging from 0.29 to 0.54. We used a weighted-average expected life of the options of five years for each of 2004, 2003 and 2002.

Presented below is pro forma financial information assuming Chesapeake had applied the fair value method under SFAS No. 123:

	Years Ended December 31,		
	2004	2003	2002
	($ in thousands, except per share amounts)		
Net Income:			
As reported	$515,155	$312,981	$40,286
Stock-based compensation expense included in net income, net of tax	3,090	586	214
Pro forma compensation expense, net of tax	(14,289)	(11,604)	(8,858)
Pro forma	$503,956	$301,963	$31,642
Basic earnings per common share			
As reported	$ 1.73	$ 1.38	$ 0.18
Pro forma	$ 1.69	$ 1.32	$ 0.13
Diluted earnings per common share			
As reported	$ 1.53	$ 1.21	$ 0.17
Pro forma	$ 1.49	$ 1.17	$ 0.12

For purposes of the pro forma disclosures, the estimated fair value of the options is amortized to expense over the option vesting period, which is four years for employee options.

In December 2004, the Financial Accounting Standards Board issued SFAS 123(R), *Share-Based Payment*, a revision of SFAS 123, accounting for stock-based compensation. This statement establishes standards for the accounting of transactions in which an entity exchanges its equity instruments for goods or services by requiring a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. That cost will be recognized over the period during which an employee is required to provide services in exchange for the award. The fair value of employee stock options will be estimated using option-pricing models. Excess tax benefits will be recognized as an addition to paid-in capital. Cash retained as a result of those excess tax benefits will be presented in the statement of cash flows as financing cash inflows. The write-off of deferred tax assets relating to unrealized tax benefits associated with recognized compensation cost will be recognized as income tax expense unless there are excess tax benefits from previous awards remaining in paid-in capital to which it can be offset. This statement is effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005.

Chesapeake will implement SFAS 123(R) in the third quarter of 2005 and the Black-Scholes option pricing model will be used to value the stock options as of the grant date. Based on the stock options outstanding and unvested at December 31, 2004 and our current intention to limit future awards of stock options, we do not believe the new accounting requirement will have a significant impact on future results of operations.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for 2003 and 2002 to conform to the presentation used for the 2004 consolidated financial statements.

2. Net Income Per Share

Statement of Financial Accounting Standards No. 128, *Earnings Per Share*, requires presentation of "basic" and "diluted" earnings per share, as defined, on the face of the statements of operations for all entities with complex capital structures. SFAS 128 requires a reconciliation of the numerator and denominator of the basic and diluted EPS computations.

The following securities were not included in the calculation of diluted earnings per share, as the effect was antidilutive:

- For the years ended December 31, 2004, 2003 and 2002, outstanding options to purchase 0.1 million, 1.9 million, and 0.6 million shares of common stock at a weighted-average exercise price of $23.82, $11.15, and $11.93, respectively, were antidilutive because the exercise prices of the options were greater than the average market price of the common stock.
- For the year ended December 31, 2004, diluted shares do not include the common stock equivalent of the 6% preferred stock outstanding prior to conversion (convertible into 21,339,375 shares) as the effect was antidilutive and the preferred stock dividend adjustment to net income does not include $12.2 million dividends related to these preferred shares.
- For the years ended December 31, 2003 and 2002, outstanding warrants to purchase 0.4 million and 0.6 million shares of common stock at a weighted-average exercise price of $14.55 and $14.51, respectively, were antidilutive because the exercise prices of the warrants were greater than the average market price of the common stock.
- For the year ended December 31, 2002, diluted shares do not include the assumed conversion of the outstanding 6.75% preferred stock (convertible into 19.5 million common shares) and the common stock equivalent of preferred stock outstanding prior to conversion (convertible into 5,693 shares) as the effects were antidilutive.

The Emerging Issues Task Force (EITF) Issue 04-8, *The Effect of Contingently Convertible Instruments on Diluted Earnings Per Share*, which was issued in September 2004, provides new guidance on when the dilutive effect of contingently convertible securities with a market price trigger should be included in diluted EPS. The new guidance states that these securities should be included in the diluted EPS computation regardless of whether the market price trigger has been met. The guidance in EITF 04-8 is effective for all periods ending after December 15, 2004 and has been applied retrospectively by restating previously reported EPS. Accordingly, effective December 15, 2004, the company has assumed the conversion of the 4.125% convertible preferred share issued in 2004 (if dilutive) for purposes of determining earnings per share assuming dilution.

A reconciliation for the years ended December 31, 2004, 2003 and 2002 is as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in thousands, except per share data)		
For the Year Ended December 31, 2004:			
Basic EPS:			
Income available to common shareholders	$438,971	253,212	$1.73
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.125% convertible preferred stock	—	14,200	
Common shares assumed issued for 5.00% convertible preferred stock	—	10,516	
Common shares assumed issued for 6.00% convertible preferred stock	—	501	
Common shares assumed issued for 6.75% convertible preferred stock	—	16,971	
Preferred stock dividends	27,290	—	
Employee stock options	—	10,097	
Restricted stock	—	203	
Warrants assumed in Gothic Acquisition	—	18	
Diluted EPS Income available to common shareholders and assumed conversions	$466,261	305,718	$1.53
For the Year Ended December 31, 2003:			
Income before cumulative effect of accounting change, net of tax	$310,592		
Preferred stock dividends	(22,469)		
Basic EPS:			
Income available to common shareholders before cumulative effect of accounting change, net of tax	$288,123	211,203	$1.36
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 5.00% convertible preferred stock	—	1,441	
Common shares assumed issued for 6.00% convertible preferred stock	—	18,499	
Common shares assumed issued for 6.75% convertible preferred stock	—	19,467	
Preferred stock dividends	22,469	—	
Employee stock options	—	7,957	
Diluted EPS Income available to common shareholders before cumulative effect of accounting change, net of tax	$310,592	258,567	$1.20
For the Year Ended December 31, 2002:			
Basic EPS:			
Income available to common shareholders	$ 30,169	166,910	$0.18
Effect of Dilutive Securities			
Employee stock options	—	5,797	
Warrants assumed in Gothic acquisition	—	7	
Diluted EPS Income available to common shareholders	$ 30,169	172,714	$0.17

3. Senior Notes and Revolving Bank Credit Facility

Our long-term debt consisted of the following at December 31, 2004 and 2003:

	December 31, 2004	December 31, 2003
	($ in thousands)	
8.375% Senior Notes due 2008	$ 18,990	$ 209,815
8.125% Senior Notes due 2011	245,407	728,255
9.0% Senior Notes due 2012	300,000	300,000
7.5% Senior Notes due 2013	363,823	363,823
7.0% Senior Notes due 2014	300,000	—
7.5% Senior Notes due 2014	300,000	—
7.75% Senior Notes due 2015	300,408	236,691
6.375% Senior Notes due 2015	600,000	—
6.875% Senior Notes due 2016	670,437	200,000
7.875% Senior Notes due 2004	—	42,137
8.5% Senior Notes due 2012	—	4,290
Revolving bank credit facility	59,000	—
Discount on senior notes	(84,924)	(26,959)
Premium (discount) for interest rate derivatives (a)	1,968	(339)
Total notes payable and long-term debt	$3,075,109	$2,057,713

(a) See note 10 for further discussion related to these instruments.

During the past three years, we have repurchased or exchanged Chesapeake debt and incurred losses in connection with these transactions. The following table shows the losses related to these transactions for 2004, 2003 and 2002, respectively ($ in millions):

	Notes Retired	Loss on Repurchases/Exchanges: Premium	Other(a)	Total
For the Year Ended December 31, 2004:				
8.375% Senior Notes due 2008	$190.8	$16.1	$ 1.5	$17.6
8.5% Senior Notes due 2012	4.3	0.2	0.7	0.9
8.125% Senior Notes due 2011	482.8	—	6.0	6.0
	$677.9	$16.3	$ 8.2	$24.5
For the Year Ended December 31, 2003:				
8.5% Senior Notes due 2012	$106.4	$ 6.7	$14.1(b)	$20.8
For the Year Ended December 31, 2002:				
7.875% Senior Notes due 2004	$107.9	$ 3.7	$ (1.1)(c)	$ 2.6

(a) Includes the write-off of unamortized discounts, deferred charges, transaction costs and derivative charges as described below.
(b) Includes a $12.0 million loss that was recognized based on the hedging relationship between the notes and the interest rate derivative.
(c) Includes a $1.7 million gain that was recognized based on the hedging relationship between the notes and the interest rate derivative.

In 2003 and 2004, we completed financing transactions that extended the maturity and lowered the interest rate of our outstanding senior notes. This was accomplished by issuing new senior notes with lower interest rates and extended maturity dates in exchange for existing senior notes. For accounting purposes, the notes exchanged were determined to have substantially similar terms based on their associated future cash flows. Accordingly, unless otherwise noted, these exchanges resulted in no gain or loss being recorded on our consolidated statements of operations.

In January and February of 2004, we issued $37.0 million of our 6.875% Senior Notes due 2016 in exchange for $24.3 million of our 8.125% Senior Notes due 2011 and $9.1 million of our 7.75% Senior Notes due 2015 in four private exchange transactions. In January 2004, we completed a public exchange offer in which we retired $458.5 million of our 8.125% Senior Notes due 2011 and issued $72.8 million of our 7.75% Senior Notes due 2015 and $433.5 million of our 6.875% Senior Notes due 2016. In connection with this exchange, we recorded a pre-tax charge of $6.0 million, consisting of a $5.7 million underwriter's fee and $0.3 million in other transaction costs. In October 2003, we issued $63.8 million of our 7.50% Senior Notes due 2013 and $23.7 million of our 7.75% Senior Notes due 2015 in exchange for $71.7 million of our 8.125% Senior Notes due 2011 and $12.3 million of our 8.375% Senior Notes due 2008 pursuant to a privately negotiated transaction. In August 2003, we issued $33.5 million of our 7.75% Senior Notes due 2015 in exchange for $32.0 million of our 8.5% senior notes due 2012 pursuant to a privately negotiated transaction. In July 2003, we issued $29.5 million of our 7.75% Senior Notes due 2015 in exchange for $27.9 million of our 8.375% Senior Notes pursuant to a privately negotiated transaction.

The senior note indentures permit us to redeem the senior notes at any time at specified make-whole or redemption prices. The indentures contain covenants limiting us and our subsidiaries with respect to asset sales; the incurrence of additional indebtedness and the issuance of preferred stock; liens; sale and leaseback transactions; lines of business; dividend and other payment restrictions; mergers or consolidations; and transactions with affiliates.

Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under our outstanding senior notes have been fully and unconditionally guaranteed, on a joint and several basis, by all of our subsidiaries including Chesapeake Energy Marketing, Inc., Mayfield Processing, LLC and Mid-Con Compression, L.P., for which the guarantee became effective on September 21, 2004.

We have a $1.25 billion revolving bank credit facility which matures in January 2010. As of December 31, 2004, we had $59.0 million of outstanding borrowings under our facility and utilized $122.5 million of the facility for various letters of credit. Borrowings under our facility are collateralized by certain producing oil and gas properties and bear interest at either (i) the greater of the reference rate of Union Bank of California, N.A. or the federal funds effective rate plus 0.50% or (ii) the London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are determined periodically. The unused portion of the facility is subject to an annual commitment fee that also varies according to our senior unsecured long-term debt ratings. Currently, the annual commitment fee rate is 0.30%. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which govern our ability to incur additional indebtedness, sell properties, purchase or redeem our capital stock, make investments or loans, and create liens. Prior to its amendment and restatement in January 2005, the credit facility agreement required us to maintain a current ratio (as defined) of at least 1 to 1 and a fixed charge coverage ratio (as defined) of at least 2.5 to 1. At December 31, 2004, our current ratio was 1.1 to 1 and our fixed charge coverage ratio was

5.6 to 1. As amended, the agreement no longer includes a current ratio test. The 2.5 to 1 fixed charge coverage ratio continues to apply and a new financial covenant was added requiring an indebtedness to EBITDA ratio (as defined) not to exceed 3.5 to 1. Under this test, our indebtedness to EBITDA ratio at December 31, 2004 was 2.1 to 1. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million or more, would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $50 million.

Our subsidiary, Chesapeake Exploration Limited Partnership, is the borrower under our revolving bank credit facility and is the named party to our hedging facility. The facilities are guaranteed by Chesapeake and all of our subsidiaries.

4. Contingencies and Commitments

Litigation. Chesapeake is currently involved in various disputes incidental to its business operations. Management, after consultation with legal counsel, is of the opinion that the final resolution of all currently pending or threatened litigation is not likely to have a material adverse effect on our consolidated financial position or results of operations.

Employment Agreements with Officers. Chesapeake has employment agreements with its chief executive officer, chief operating officer, chief financial officer and various other senior management personnel, which provide for annual base salaries, bonus compensation and various benefits. The agreements provide for the continuation of salary and benefits for varying terms in the event of termination of employment without cause. The agreements with the chief executive officer and chief operating officer have terms of five years commencing January 1, 2004. The term of each agreement is automatically extended for one additional year on each January 31 unless one of the parties provides 30 days notice of non-extension. The agreements with the chief financial officer and other senior managers expire on September 30, 2006. The company’s employment agreements with the executive officers provide for payments in the event of a change in control. The chief executive officer and chief operating officer are each entitled to receive a payment in the amount of five times his base compensation plus bonuses and the prior year’s benefits, plus a tax gross-up payment, and the chief financial officer and other officers are each entitled to receive a payment in the amount of two times his or her base compensation plus bonuses paid during the prior year.

Environmental Risk. Due to the nature of the oil and gas business, Chesapeake and its subsidiaries are exposed to possible environmental risks. Chesapeake has implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. Chesapeake conducts periodic reviews, on a company-wide basis, to identify changes in our environmental risk profile. These reviews evaluate whether there is a probable liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. Depending on the extent of an identified environmental problem, Chesapeake may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property. Chesapeake has historically not experienced any significant environmental liability, and is not aware of any potential material environmental issues or claims at December 31, 2004.

Other. We completed an acquisition of Mid-Continent and Ark-La-Tex oil and gas assets from BRG Petroleum Corporation in February 2005. We paid approximately $325 million in cash for these assets, $16.3 million of which was paid in 2004.

Chesapeake has entered into various operating leases for office space and equipment. Future minimum lease payments required as of December 31, 2004 related to these operating leases are as follows ($ in thousands):

2005	$2,415
2006	1,517
2007	1,133
2008	613
2009	240
After 2009	1,099
Total	$7,017

Rent expense, including short-term rentals, for the years ended December 31, 2004, 2003 and 2002 was $17.9 million, $13.1 million and $7.7 million, respectively.

5. Income Taxes

The components of the income tax provision (benefit) for each of the periods presented below are as follows:

	Years Ended December 31,		
	2004	2003	2002
		($ in thousands)	
Current	$ —	$ 5,000	$ (1,822)
Deferred	289,771	186,824	28,676
Total	$289,771	$191,824(a)	$26,854

(a) Includes $1,464,000 of tax expense related to the cumulative effect of a change in accounting principle.

The effective income tax expense differed from the computed "expected" federal income tax expense on earnings before income taxes for the following reasons:

	Years Ended December 31,		
	2004	2003	2002
		($ in thousands)	
Computed "expected" federal income tax provision	$281,724	$176,682	$23,499
State income taxes and other	8,230	10,968	3,492
Change in valuation allowance	—	4,364	—
Tax percentage depletion	(183)	(190)	(137)
	$289,771	$191,824	$26,854

Deferred income taxes are provided to reflect temporary differences in the basis of net assets for income tax and financial reporting purposes. The tax-effected temporary differences and tax loss carryforwards which comprise deferred taxes are as follows:

	Years Ended December 31,	
	2004	2003
	($ in thousands)	
Deferred tax liabilities:		
Oil and gas properties	$(1,121,776)	$(346,773)
Other property and equipment	(18,128)	(8,682)
Derivative instruments	(10,798)	—
Investments	(5,944)	—
Deferred tax liabilities	$(1,156,646)	$(355,455)
Deferred tax assets:		
Net operating loss carryforwards	$ 199,897	$ 154,784
Asset retirement obligation	26,907	18,549
Derivative instruments	—	12,159
Investments	—	11,907
Percentage depletion carryforwards	3,801	3,228
Alternative minimum tax credits	5,344	5,011
Other	4,892	2,301
Deferred tax assets	$ 240,841	$ 207,939
Net deferred tax (liability) asset	$ (915,805)	$(147,516)
Less: Valuation allowance	—	(6,805)
Total deferred tax (liability) asset	$ (915,805)[a]	$(154,321)
Reflected in accompanying balance sheets as:		
Current deferred income tax asset	$ 18,068	$ 36,705
Non-current deferred income tax liability	(933,873)	(191,026)
	$ (915,805)	$(154,321)

(a) In addition to the income tax expense of $289.8 million, activity during 2004 includes a net liability of $464.0 million related to acquisitions, a liability of $13.9 million related to investments, a liability of $10.0 million related to derivative instruments, a benefit of $9.1 million related to stock option compensation, a benefit of $6.8 million related to the valuation allowance reversal, a benefit of $0.2 million related to state income tax payments made, and a benefit of $0.1 million related to AMT payments made on behalf of an acquired entity. These items were not recorded as part of the provision for income taxes.

SFAS 109 requires that we record a valuation allowance when it is more likely than not that some portion or all of deferred tax assets will not be realized. As of December 31, 2001, we determined that it was more likely than not that $2.4 million of the net deferred tax assets related to net operating losses generated by Louisiana properties would not be realized and had recorded a valuation allowance equal to such amount. During 2003, we determined that it was more likely than not that an additional $4.4 million of the deferred tax assets related to Louisiana net operating losses would not be realized and we recorded an additional valuation allowance equal to such amounts. During 2004, we determined that it was more likely than not that the $6.8 million of the deferred tax assets related to Louisiana net operating losses would be realized due to the acquisitions occurring in 2004. The recognition of the deferred tax asset was included as a component of the acquisition of the properties and was not reflected as a reduction of the 2004 provision for income tax.

As of December 31, 2004, we classified $18.1 million of deferred tax assets as current that were attributable to the current portion of derivative liabilities and other current temporary differences. As of December 31, 2003, we classified $36.7 million of deferred tax assets as current that were attributable to the current portion of derivative liabilities and other current temporary differences.

At December 31, 2004, Chesapeake had federal income tax net operating loss (NOL) carryforwards of approximately $545.8 million. Additionally, we had $114.0 million of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income and approximately $10.4 million of percentage depletion carryforwards. The NOL carryforwards expire from 2012 through 2024. The value of these carryforwards depends on the ability of Chesapeake to generate taxable income. In addition, for AMT purposes, only 90% of AMT income in any given year may be offset by AMT NOLs. A summary of our NOLs follows:

	NOL	AMT NOL
	($ in thousands)	
Expiration Date:		
December 31, 2012	$171,588	$ —
December 31, 2018	42,187	—
December 31, 2019	142,711	57,414
December 31, 2020	5,156	1,393
December 31, 2021	15,423	5,334
December 31, 2022	46,157	20,685
December 31, 2023	57,045	29,195
December 31, 2024	65,581	—
Total	$545,848	$114,021

The ability of Chesapeake to utilize NOL carryforwards to reduce future federal taxable income and federal income tax of Chesapeake is subject to various limitations under the Internal Revenue Code of 1986, as amended. The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the issuance or exercise of rights to acquire stock, the purchase or sale of stock by 5% stockholders, as defined in the Treasury regulations, and the offering of stock by us during any three-year period resulting in an aggregate change of more than 50% in the beneficial ownership of Chesapeake.

In the event of an ownership change (as defined for income tax purposes), Section 382 of the Code imposes an annual limitation on the amount of a corporation's taxable income that can be offset by these carryforwards. The limitation is generally equal to the product of (i) the fair market value of the equity of the company multiplied by (ii) a percentage approximately equivalent to the yield on long-term tax exempt bonds during the month in which an ownership change occurs. In addition, the limitation is increased if there are recognized built-in gains during any post-change year, but only to the extent of any net unrealized built-in gains (as defined in the Code) inherent in the assets sold. Certain NOLs acquired through various acquisitions are also subject to limitations.

The following table summarizes our net operating losses as of December 31, 2004 and any related limitations:

	Total	Limited	Annual Limitation
		($ in thousands)	
Net operating loss	$545,848	$118,089	$50,030
AMT net operating loss	$114,021	$ 38,479	$18,045

Although no assurances can be made, we do not believe that an ownership change has occurred as of December 31, 2004. Future equity transactions by Chesapeake or by 5% stockholders (including relatively small transactions and transactions beyond our control) could cause an ownership change and therefore a limitation on the annual utilization of NOLs.

6. Related Party Transactions

As of December 31, 2004, we had accrued accounts receivable from our CEO and COO of $4.2 million and $4.0 million, respectively, representing joint interest billings from December 2004 which were invoiced and paid in January 2005. Since Chesapeake was founded in 1989, our chief executive officer and chief operating officer have acquired small working interests in certain of our oil and gas properties by participating in our drilling activities. Joint interest billings to the CEO and COO are settled in cash immediately upon delivery of a monthly joint interest billing.

Under their employment agreements, the CEO and COO are permitted to participate in all or none of the wells drilled by or on behalf of Chesapeake during each calendar quarter, but they are not allowed to participate only in selected wells. A participation election is required to be received by the Compensation Committee of Chesapeake's Board of Directors 30 days prior to the start of a quarter. Their participation is permitted only under the terms outlined in their employment agreements, which, among other things, limit their individual participation to a maximum working interest of 2.5% in a well and prohibits participation in situations where Chesapeake's working interest would be reduced below 12.5% as a result of their participation. In addition, the company is reimbursed for the cost of its leasehold acquired by the CEO and COO as a result of their well participation.

As discussed in Note 8, in 2004, Chesapeake had revenues of $467.4 million from oil and gas sales to an affiliated entity.

During 2004, 2003 and 2002, we paid legal fees of $1.1 million, $2.1 million and $0.6 million, respectively, for legal services provided by a law firm of which a director is a member.

7. Employee Benefit Plans

We maintain two qualified 401(k) profit sharing plans, the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan, which is open to employees of Chesapeake and all our subsidiaries except Nomac Drilling Corporation, and the Nomac Drilling 401(k) Plan, which is open to employees of Nomac Drilling Corporation. Eligible employees may elect to defer voluntary contributions to the plans, subject to plan limits and those set by the Internal Revenue Service. Chesapeake matches contributions to the Chesapeake Savings and Incentive Stock Bonus Plan dollar for dollar with Chesapeake common stock purchased in the open market for up to 15% of an employee's annual compensation. The company contributed $6.9 million, $4.0 million and $2.9 million to this plan during 2004, 2003 and 2002, respectively. The company matched contributions to the Nomac Drilling 401(k) Plan dollar for dollar with Chesapeake common stock purchased in the open market for up to 6% of the participating employee's annual compensation from the plan's inception in July 2003 through December 31, 2004. Beginning January 1, 2005, the matching contribution to the Nomac plan was increased to 8%. The company contributed $0.2 million and $0.1 million to this plan in 2004 and 2003, respectively.

In January 2003, we established a 401(k) make-up plan and a deferred compensation plan, both of which are nonqualified deferred compensation plans. Employees eligible to participate in these plans were able to defer annual compensation for up to a total of 60% of their base salary and 100% of any cash performance bonus through contributions to the plans, including contributions made to the Chesapeake 401(k) Plan.

To be eligible to participate in the 2003 401(k) make-up plan, an employee had to receive annual compensation (base salary and bonus combined) of at least $90,000, have a minimum of five years of service as a company employee and have made the maximum contribution allowable under the 401(k) plan. The company matched employee contributions to the 401(k) make-up plan in Chesapeake common stock dollar for dollar for up to 15% of the employee's annual compensation. We contributed $1.4 million and $1.2 million to the 401(k) make-up plan during 2004 and 2003, respectively. Non-employee directors and employees receiving an annual base salary of at least $100,000 were eligible to participate in the 2003 deferred compensation plan. Non-employee directors were able to defer up to 100% of director fees. Chesapeake made no matching or other contributions to the deferred compensation plan, although the plan permits the company to make discretionary contributions.

In December 2004, Chesapeake established a new 401(k) make-up plan and a new deferred compensation plan in response to the American Jobs Creation Act of 2004, which set out new guidelines for such plans. The 2003 plans remain in place but will receive no additional deferrals. The new plans both have an annual compensation eligibility threshold of $95,000 (base salary and bonus combined) and the maximum compensation that can be deferred under all company deferred compensation plans, including the Chesapeake 401(k) Plan, has been increased to a total of 75% of base salary and 100% of performance bonus. Other material eligibility and participation terms of the plans not affected by the American Job Creation Act of 2004 remain the same. The company continues to provide matching contributions in common stock to the new 401(k) make-up plan dollar for dollar up to 15% of a participating employee's annual compensation. The company does not make matching or other contributions to the new deferred compensation plan.

Any assets placed in trust by Chesapeake to fund future obligations of the 401(k) make-up plans and the deferred compensation plans are subject to the claims of creditors in the event of insolvency or bankruptcy, and participants are general creditors of the company as to their deferred compensation in the plans.

8. Major Customers and Segment Information

Sales to individual customers constituting 10% or more of total revenues were as follows:

Year Ended December 31,	Customer	Amount	Percent of Total Revenues
		($ in thousands)	
2004	Eagle Energy Partners I, L.P.	$467,387	17%
2003	Reliant Energy Services	$189,140	11%
2003	Duke Energy Field Services	$163,329	10%
2002	Continental Natural Gas	$123,813	17%
2002	Reliant Energy Services	$ 96,682	13%
2002	Duke Energy Field Services	$ 83,115	11%

In September 2003, Chesapeake invested $5.8 million in Eagle Energy Partners I, L.P. ("Eagle") and received a 25% limited partnership interest. Through additional investments totaling $1.9 million, Chesapeake has increased its limited partner ownership interest in Eagle Energy Partners I, L.P. to approximately 30% as of December 31, 2004. Chesapeake accounts for its investment in Eagle Energy Partners I, L.P. under the equity method of accounting in accordance with APB 18.

In accordance with SFAS 131, *Disclosures about Segments of an Enterprise and Related Information*, we have identified two reportable operating segments. These segments are managed separately because of the nature of their products and services. Chesapeake's two segments are the exploration and production segment and the marketing segment. The exploration and production segment is responsible for finding and producing natural gas and crude oil. The marketing segment is responsible for gathering, processing, transporting, and selling natural gas and crude oil production primarily from Chesapeake operated wells. Management evaluates the performance of our segments based upon income before income taxes and cumulative effect of accounting change. Revenues from the marketing segment's sale of oil and gas related to Chesapeake's ownership interests are reflected as exploration and production revenues. Such amounts totaled $1,349.1 million, $875.3 million and $378.1 million for 2004, 2003 and 2002, respectively.

For the Year Ended December 31, 2004:	Exploration and Production	Marketing	Consolidated
Revenues	$1,936,176	$773,092	$2,709,268
Production expenses and taxes	308,752	—	308,752
General and administrative expenses	30,506	6,539	37,045
Oil and gas marketing expenses	—	755,314	755,314
Depreciation, depletion and amortization	602,894	8,428	611,322
Interest and other income	3,944	532	4,476
Interest expense	167,328	—	167,328
Provision for legal settlements	4,500	—	4,500
Other expense	24,557	—	24,557
INCOME BEFORE INCOME TAXES	801,583	3,343	804,926
Income tax expense	288,567	1,204	289,771
NET INCOME	$ 513,016	$ 2,139	$ 515,155
TOTAL ASSETS, END OF PERIOD	$7,926,263	$318,246	$8,244,509
CAPITAL EXPENDITURES	$3,869,808	$ 42,462	$3,912,270
For the Year Ended December 31, 2003:			
Revenues	$1,296,822	$420,610	$1,717,432
Production expenses and taxes	215,476	—	215,476
General and administrative expenses	20,300	3,453	23,753
Oil and gas marketing expenses	—	410,288	410,288
Depreciation, depletion and amortization	383,065	3,193	386,258
Interest and other income	1,673	1,154	2,827
Interest expense	154,345	11	154,356
Provision for legal settlement	6,402	—	6,402
Other expenses	22,774	—	22,774
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	496,133	4,819	500,952
Income tax expense	188,529	1,831	190,360
NET INCOME	$ 307,604	$ 2,988	$ 310,592
TOTAL ASSETS, END OF PERIOD	$4,376,558	$195,733	$4,572,291
CAPITAL EXPENDITURES	$2,086,102	$ 27,265	2,113,367

For the Year Ended December 31, 2002:	Exploration and Production	Marketing	Consolidated
Revenues	$ 568,187	$170,315	$ 738,502
Production expenses and taxes	128,292	—	128,292
General and administrative expenses	15,684	1,934	17,618
Oil and gas marketing expenses	—	165,736	165,736
Depreciation, depletion and amortization	233,378	1,820	235,198
Interest and other income	6,743	597	7,340
Interest expense	112,021	10	112,031
Other expenses	19,827	—	19,827
INCOME BEFORE INCOME TAXES	65,728	1,412	67,140
Income tax expense	26,289	565	26,854
NET INCOME	$ 39,439	$ 847	$ 40,286
TOTAL ASSETS, END OF PERIOD	$2,772,496	$103,112	$2,875,608
CAPITAL EXPENDITURES	$ 826,088	$ 7,281	$ 833,369

9. Stockholders' Equity, Restricted Stock and Stock Options

In 2004, holders of our 6.75% cumulative convertible preferred stock converted 2,998,000 shares into 19,467,482 shares of common stock (at a conversion price of $7.70 per share).

In 2004, a holder of our 6.0% cumulative convertible preferred stock exchanged 600,000 shares for 3,225,000 shares of common stock in a privately negotiated transaction, and holders exchanged 3,896,890 shares of such preferred stock for 20,754,817 shares of common stock in a public exchange offer.

In August 2004, we issued 23,000,000 shares of Chesapeake common stock at $14.75 per share in a public offering for net proceeds of $326.2 million.

In March and April 2004, we issued 313,250 shares of 4.125% cumulative convertible preferred stock, par value $.01 per share and liquidation preference $1,000 per share, in a private offering, all of which were outstanding as of December 31, 2004. The net proceeds from the offering were $304.9 million. Each share of preferred stock is convertible initially into 60.0555 shares of common stock (which is calculated using an initial conversion price of $16.65 per share of common stock), subject to adjustment upon the occurrence of certain events. A holder's right to convert will arise only when (i) the closing sale price of our common stock reaches or exceeds 130% of the conversion price for a specified period of time; (ii) the trading price of the preferred stock falls below 98% of the product of the closing sale price of our common stock and the conversion price for a specified period of time; or (iii) upon the occurrence of certain corporate transactions. At December 31, 2004, 18,812,385 shares of our common stock were reserved for issuance upon conversion. The preferred stock is subject to mandatory conversion, at our option, on or after March 15, 2009 (1) at the same rate if the market price of the common stock equals or exceeds 130% of the conversion price, or $21.65, for a specified time period and (2) at the lower of the conversion price and the then current market price of common stock if there are less than 25,000 shares of preferred stock outstanding at the time. Annual cumulative cash dividends of $41.25 per share are payable quarterly on the fifteenth day of each March, June, September and December.

In January 2004, we issued 23,000,000 shares of Chesapeake common stock at $13.51 per share in a public offering for net proceeds of $298.1 million.

In November 2003, we issued 1,725,000 shares of 5.00% cumulative convertible preferred stock, par value $.01 per share and liquidation preference $100 per share, in a public offering, all of which were outstanding as of

December 31, 2004. The net proceeds from the offering were $167.6 million. Each preferred share is convertible at any time at the option of the holder into 6.0962 shares of common stock, subject to adjustment. At December 31, 2004, 10,515,945 shares of our common stock were reserved for issuance upon conversion. The conversion rate is based on an initial conversion price of $16.40 per common share plus cash in lieu of fractional shares. The preferred stock is subject to mandatory conversion, at our option, (1) on or after November 18, 2006 at the same rate, if the market price of the common stock equals or exceeds 130% of the conversion price, or $21.32, for a specified time period and (2) on or after November 18, 2008, at the lower of the conversion price and the then current market price of common stock if there are less than 250,000 shares of preferred stock outstanding at the time. Annual cumulative cash dividends of $5.00 per share are payable quarterly on the fifteenth day of each February, May, August and November.

In March 2003, we issued 23,000,000 shares of Chesapeake common stock at $8.10 per share in a public offering for net proceeds of $177.4 million.

In March 2003, we issued 4,600,000 shares of 6.00% cumulative convertible preferred stock, par value $.01 per share and liquidation preference $50 per share, in a private offering, 103,110 shares of which were outstanding as of December 31, 2004. The net proceeds from the offering were $222.8 million. Each preferred share is convertible at any time at the option of the holder into 4.8605 shares of common stock, subject to adjustment. At December 31, 2004, 501,166 shares of common stock were reserved for issuance upon conversion. The conversion rate is based on an initial conversion price of $10.287 per common share plus cash in lieu of fractional shares. The preferred stock is subject to mandatory conversion at our option, (1) on or after March 20, 2006 at the same rate if the market price of the common stock equals or exceeds 130% of the conversion price, or $13.37, at the time and (2) on or after March 20, 2008 at the lower of the conversion price and the then current market price of the common stock if there are less than 250,000 shares of preferred stock outstanding at the time. Annual cumulative cash dividends of $3.00 per share are payable quarterly on the fifteenth day of March, June, September and December.

In December 2002, we issued 23,000,000 shares of Chesapeake common stock at $7.50 per share in a public offering for net proceeds of $164.1 million.

Restricted Stock

During 2004, Chesapeake issued 2.7 million shares of restricted common stock to employees. The total value of restricted shares granted is recorded as unearned compensation in stockholders' equity based on the fair market value of the shares on the date of grant. This value is amortized over the vesting period, which is four years from the date of grant. To the extent amortization of compensation cost relates to employees directly involved in acquisition, exploration and development activities, such amounts are capitalized to oil and gas properties. Amounts not capitalized to oil and gas properties are recognized in stock-based compensation expense. Chesapeake recognized amortization of compensation cost related to restricted stock totaling $6.3 million during 2004. Of this amount, $4.2 million was reflected in stock-based compensation expense with the remaining $2.1 million capitalized to oil and gas properties. As of December 31, 2004, the unamortized balance of unearned compensation recorded as a reduction of stockholders' equity was $32.6 million.

Stock-Based Compensation Plans

Under Chesapeake's 2003 Stock Incentive Plan, restricted stock and incentive and nonqualified stock options to purchase our common stock may be awarded to employees and consultants of Chesapeake. Subject to any adjustments as provided by the plan, the aggregate number of shares which may be issued and sold may not exceed 10,000,000 shares. The maximum period for exercise of an option may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the option on the date of grant. Restricted stock and options granted become vested at dates determined by a committee of the board of directors. No restricted stock or option can be granted under this plan after April 14, 2013. This plan has been approved by our shareholders. There were 2.7 million restricted shares, net of forfeitures, issued during 2004 from this plan.

Under Chesapeake's 2003 Stock Award Plan for Non-Employee Directors, 10,000 shares of Chesapeake's common stock will be awarded to each newly appointed non-employee director on his or her first day of service. Subject to any adjustments as provided by the plan, the aggregate number of shares which may be issued may not exceed 50,000 shares. This plan was not required to be approved by our shareholders. As of December 31, 2004, one award had been made under the plan. In 2003, 10,000 shares of common stock were awarded to a new director from this plan.

Under Chesapeake's 2002 Non-Employee Director Stock Option Plan and 1992 Nonstatutory Stock Option Plan, we have granted nonqualified options to purchase our common stock to members of our board of directors who are not Chesapeake employees. Subject to any adjustments provided for in the plans, the 2002 plan and the 1992 plan cover a maximum of 500,000 shares and 3,132,000 shares, respectively. No shares remained available for option grants under the 2002 plan as of December 31, 2004, and the 1992 plan terminated on December 10, 2002. Pursuant to a formula award provision in the plans, each non-employee director received a quarterly grant of a ten-year immediately exercisable option to purchase shares of common stock at an exercise price equal to the fair market value of the shares on the date of grant. Both plans were approved by our shareholders.

In addition to the plans described above, we have a number of employee stock option plans which are described below. No options have been granted under these plans since December 2003. Beginning in 2004, all stock-based compensation awards to employees have been made in the form of restricted stock from the 2003 Stock Incentive Plan.

Name of Plan	Eligible Participants	Type of Options	Shares Covered	Expiration Date	Shareholder Approved
2002 and 2001 Stock Option Plans	Employees and consultants	Incentive and nonqualified	3,000,000/ 3,200,000	February 2012/ February 2011	Yes
2001 and 2000 Executive Officer Stock Option Plans	Executive officers	Nonqualified	4,000,000/ 2,500,000 (treasury shares only)	April 2011/ April 2010	No
2002 and 2001 Nonqualified Stock Option Plans	Employees and consultants	Nonqualified	4,000,000/ 3,000,000	February 2012/ April 2011	No
2000 Employee and 1999 Stock Option Plans	Employees and consultants	Nonqualified	3,000,000 (each plan)	April 2010/ March 2009	No
1996 and 1994 Stock Option Plans	Employees and consultants	Incentive and nonqualified	6,000,000/ 4,886,910	October 2006/ October 2004	Yes

Each of these plans provides that the maximum period for exercise of an option may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the options on the date of grant; provided, however, nonqualified stock options not exceeding 10% of the options issuable under each of the plans (except the 1996 and 1994 Stock Option Plans) may be granted at an exercise price which is not less than 85% of the grant date fair market value. The 1996 Stock Option Plan does not limit the amount of nonqualified stock options that may be granted with an exercise price of at least 85% of the fair market value of the shares underlying the options on the date of grant. The 1994 Stock Option Plan, which terminated in October 2004, did not permit options with an exercise price below the fair market value of the shares underlying the options on the date of grant. Options granted under all these plans become exercisable at dates determined by a committee of the board of directors.

A summary of our stock option activity and related information follows:

	Years Ended December 31,					
	2004		2003		2002	
	Options	Weighted-Avg. Exercise Price	Options	Weighted-Avg. Exercise Price	Options	Weighted-Avg. Exercise Price
Outstanding beginning of period	27,233,285	$ 5.78	24,576,775	$4.40	23,232,655	$3.96
Granted	347,250	14.23	7,168,623	8.98	4,170,700	5.38
Exercised	(3,219,877)	4.94	(4,262,915)	3.04	(2,519,429)	1.83
Canceled/forfeited	(132,194)	8.21	(249,198)	8.51	(307,151)	5.30
Outstanding end of period	24,228,464	$ 6.00	27,233,285	$5.78	24,576,775	$4.40
Exercisable end of period	15,441,511	$ 5.06	12,131,098	$4.26	11,014,775	$3.55
Shares authorized for future grants	8,392,285		11,018,225		7,602,339	
Fair value of options granted during Period	$ 4.66		$ 3.36		$ 2.31	

The following table summarizes information about stock options outstanding at December 31, 2004:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted-Avg. Remaining Contractual Life	Weighted-Avg. Exercise Price	Number Exercisable	Weighted-Avg. Exercise Price
$ 0.94 – $ 1.13	2,820,238	3.89	$ 1.08	2,820,238	$ 1.08
1.38 – 4.00	2,993,369	5.19	3.31	2,993,369	3.31
4.06 – 4.92	12,487	2.89	4.21	12,487	4.21
5.20 – 5.20	3,187,974	7.56	5.20	1,380,852	5.20
5.35 – 6.10	2,172,826	5.90	5.57	2,119,413	5.56
6.11 – 6.11	5,620,366	6.75	6.11	3,938,568	6.11
6.13 – 7.74	398,705	5.08	6.90	319,732	6.87
7.80 – 10.00	3,379,058	7.98	7.84	779,812	7.90
10.01 – 10.80	3,110,255	8.47	10.10	697,460	10.11
10.81 – 30.63	533,186	7.78	16.12	379,580	17.53
0.94 – 30.63	24,228,464	6.64	$ 6.00	15,441,511	$ 5.06

The exercise of certain stock options results in state and federal income tax benefits to us related to the difference between the market price of the common stock at the date of disposition and the option price. During 2004, 2003 and 2002, we recognized tax benefits of $9.1 million, $7.1 million and $2.4 million, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

Shareholder Rights Plan

Chesapeake maintains a shareholder rights plan designed to deter coercive or unfair takeover tactics, to prevent a person or group from gaining control of Chesapeake without offering fair value to all shareholders and to deter other abusive takeover tactics which are not in the best interest of shareholders.

Under the terms of the plan, each share of common stock is accompanied by one right, which given certain acquisition and business combination criteria, entitles the shareholder to purchase from Chesapeake one one-thousandth of a newly issued share of Series A preferred stock at a price of $25.00, subject to adjustment by Chesapeake.

The rights become exercisable 10 days after Chesapeake learns that an acquiring person (as defined in the plan) has acquired 15% or more of the outstanding common stock of Chesapeake or 10 business days after the commencement of a tender offer which would result in a person owning 15% or more of such shares. Chesapeake may redeem the rights for $0.01 per right within ten days following the time Chesapeake learns that a person has become an acquiring person. The rights will expire on July 27, 2008, unless redeemed earlier by Chesapeake.

10. Financial Instruments and Hedging Activities

Oil and Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of December 31, 2004, our oil and gas derivative instruments were comprised of swaps, cap-swaps, basis protection swaps, call options and collars. These instruments allow us to predict with greater certainty the effective oil and gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

- For swap instruments, Chesapeake receives a fixed price for the hedged commodity and pays a floating market price, as defined in each instrument, to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.
- For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a "cap" limiting the counterparty's exposure. In other words, there is no limit to Chesapeake's exposure but there is a limit to the downside exposure of the counterparty. Because this derivative includes a written put option (i.e., the cap), cap-swaps do not qualify for designation as cash flow hedges (in accordance with SFAS 133) since the combination of the hedged item and the written put option does not provide as much potential for favorable cash flows as exposure to unfavorable cash flows.
- Basis protection swaps are arrangements that guarantee a price differential of oil or gas from a specified delivery point. Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.
- For call options, Chesapeake receives a cash premium from the counterparty in exchange for the sale of a call option. If the market price exceeds the fixed price of the call option, then Chesapeake pays the counterparty such excess. If the market price settles below the fixed price of the call option, no payment is due from Chesapeake.
- Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.

Chesapeake enters into counter-swaps from time to time for the purpose of locking in the value of a swap. Under the counter-swap, Chesapeake receives a floating price for the hedged commodity and pays a fixed price to the counterparty. The counter-swap is 100% effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap. We refer to this locked-in value as a locked swap. At the time Chesapeake enters into a counter-swap, Chesapeake removes the original swap's designation as a cash flow hedge and classifies the original swap as a non-qualifying hedge under SFAS 133. The reason for this new designation is that collectively the swap and the counter-swap no longer hedge the exposure to variability in expected future cash flows. Instead, the swap and counter-swap effectively lock in a specific gain (or loss) that will be unaffected by subsequent variability in oil and gas prices. Any locked in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and gas sales in the month of related production.

With respect to counter-swaps that are designed to lock in the value of cap-swaps, the counter-swap is effective in locking in the value of the cap-swap until the floating price reaches the cap (or floor) stipulated in the cap-swap agreement. The value of the counter-swap will increase (or decrease), but in the opposite direction, as the value of the cap-swap decreases (or increases) until the floating price reaches the pre-determined cap (or floor) stipulated in the cap-swap agreement. However, because of the written put option embedded in the cap-swap, the changes in value of the cap-swap are not completely effective in offsetting changes in value of the corresponding counter-swap. Changes in the value of the cap-swaps and the counter-swaps are recorded as adjustments to oil and gas sales.

In accordance with FASB Interpretation No. 39, Chesapeake nets the value of its derivative arrangements with the same counterparty in the accompanying consolidated balance sheets, to the extent that a legal right of setoff exists.

Chesapeake enters into basis protection swaps for the purpose of locking in a price differential of oil or gas for a specified delivery point. We currently have basis protection swaps covering four different delivery points which correspond to the actual price we receive for much of our gas production. By entering into these basis protection swaps, we have effectively reduced our exposure to market changes in future gas price differentials. As of December 31, 2004, the fair value of our basis protection swaps was $122.3 million. As of December 31, 2004, our basis protection swaps cover 48% of our anticipated gas production in 2005, 30% in 2006, 27% in 2007, 24% in 2008 and 17% in 2009.

Gains or losses from derivative transactions are reflected as adjustments to oil and gas sales on the consolidated statements of operations. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within oil and gas sales. Unrealized gains (losses) included in oil and gas sales in 2004, 2003 and 2002 were $40.9 million, $10.5 million and ($87.3) million, respectively.

Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and gas sales as unrealized gains (losses). We recorded a gain (loss) on ineffectiveness of ($8.2) million, ($9.2) million and ($3.6) million in 2004, 2003 and 2002, respectively.

The estimated fair values of our oil and gas derivative instruments as of December 31, 2004 and 2003 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	December 31, 2004	December 31, 2003
	($ in thousands)	
Derivative assets (liabilities):		
Fixed-price gas swaps	$ 57,073	$(44,794)
Fixed-price gas locked swaps	(77,299)	1,777
Fixed-price gas cap-swaps	(48,761)	(18,608)
Fixed-price gas counter swaps	4,654	—
Gas basis protection swaps	122,287	46,205
Gas call options(a)	(5,793)	(17,876)
Fixed-price gas collars	(5,573)	—
Fixed-price oil cap-swaps	(8,238)	(11,692)
Estimated fair value	$ 38,350	$(44,988)

(a) After adjusting for the remaining $3.2 million and $16.8 million premium paid to Chesapeake by the counterparty, the cumulative unrealized loss related to these call options as of December 31, 2004 and 2003 was ($2.6) million and ($1.1) million, respectively.

Based upon the market prices at December 31, 2004, we expect to transfer approximately $7.3 million of the income included in the balance in accumulated other comprehensive income to earnings during the next 12 months when the transactions actually close. All transactions hedged as of December 31, 2004 are expected to mature by December 31, 2007, with the exception of our basis protection swaps which extend through 2009.

Interest Rate Derivatives

We utilize hedging strategies to manage our exposure to changes in interest rates. To the extent interest rate swaps have been designated as fair value hedges, changes in the fair value of the derivative instrument and the corresponding debt are reflected as adjustments to interest expense in the corresponding months covered by the derivative agreement. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

As of December 31, 2004, the following interest rate swaps to convert a portion of our long-term fixed rate debt to floating rate debt were outstanding:

Term	Notional Amount	Fixed Rate	Floating Rate	Fair Value as of December 31, 2004
				($ in thousands)
November 2004 – June 2014	$75,000,000	7.500%	6-month LIBOR in arrears plus 254 basis points	$(333)
November 2004 – January 2015	$75,000,000	7.750%	6-month LIBOR in arrears plus 291 basis points	$(914)
September 2004 – August 2012	$75,000,000	9.000%	6-month LIBOR plus 452 basis points	$(269)

During 2004, we entered into and subsequently closed five separate interest rate swaps for a total gain of $3.8 million. These interest rate swaps were designated as fair value hedges of the related senior notes. The settlement amounts received will be amortized as a reduction to realized interest expense over the remaining terms of the related senior notes. The senior notes hedged mature in 2014 and 2015.

In 2005, we closed the 7.5% and 7.75% interest rate swaps for gains totaling $0.8 million. These interest rate swaps were designated as fair value hedges of the related senior notes. The settlement amounts received will be amortized as a reduction to realized interest expense over the remaining terms of the related senior notes. The senior notes hedged mature in 2014 and 2015.

In March 2004, Chesapeake entered into an interest rate swap which requires Chesapeake to pay a fixed rate of 8.68% while the counterparty pays Chesapeake a floating rate of six month LIBOR plus 0.75% on a notional amount of $142.7 million. The counterparty may elect to terminate the swap and cause it to be settled at the then current estimated fair value of the interest rate swap on March 15, 2005 and annually thereafter until March 15, 2011. The interest rate swap expires on March 15, 2012. Chesapeake may elect to terminate the swap and cause it to be settled at the then current estimated fair value of the interest rate swap at any time during the term of the swap.

As of December 31, 2004, the fair value of the interest rate swap was a liability of $34.3 million. Because the interest rate swap is not designated as a fair value hedge, changes in the fair value of the swap are recorded as adjustments to interest expense. In 2004, interest expense related to the swap includes an unrealized loss of $4.2 million and a realized loss of $2.2 million.

In January 2004, Chesapeake acquired a $50 million interest rate swap as part of the purchase of Concho Resources Inc. Under the terms of the interest rate swap, the counterparty pays Chesapeake a floating three-month LIBOR rate and Chesapeake pays a fixed rate of 2.875%. Payments are made quarterly and the interest rate swap extends through September 2005. An initial liability of $0.6 million was recorded based on the fair value of the interest rate swap at the time of acquisition. As of December 31, 2004, the interest rate swap had a negligible fair value. Because this instrument is not designated as a fair value hedge, an unrealized gain of $0.1 million was recognized in 2004 as part of interest expense.

Fair Value of Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of Statement of Financial Accounting Standards No. 107, *Disclosures About Fair Value of Financial Instruments*. We have determined the estimated fair value amounts by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values of items comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term, fixed-rate debt using primarily quoted market prices. Our carrying amount for such debt, excluding discounts for interest rate derivatives, at December 31, 2004 and 2003 was $3,014.1 million and $2,058.1 million, respectively, compared to approximate fair values of $3,281.1 million and $2,279.5 million, respectively. The carrying amounts for our 6.00% convertible preferred stock, 5.00% convertible preferred stock and 4.125% convertible preferred stock as of December 31, 2004 were $5.2 million, $172.5 million and $313.3 million, respectively, with a fair value of $9.2 million, $211.2 million and $313.3 million, respectively.

Concentration of Credit Risk

A significant portion of our liquidity is concentrated in cash and cash equivalents and derivative instruments that enable us to hedge a portion of our exposure to price volatility from producing oil and natural gas. These arrangements expose us to credit risk from our counterparties. Other financial instruments which potentially subject us to concentrations of credit risk consist principally of investments in equity instruments and accounts receivables. Our accounts receivable are primarily from purchasers of oil and natural gas products and exploration and production companies which own interests in properties we operate. The industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. Cash and cash equivalents are deposited with major banks or institutions and may at times exceed the federally insured limits.

11. Supplemental Disclosures About Oil And Gas Producing Activities

Net Capitalized Costs

Evaluated and unevaluated capitalized costs related to Chesapeake's oil and gas producing activities are summarized as follows:

	December 31,	
	2004	2003
	($ in thousands)	
Oil and gas properties:		
Proved	$ 9,451,413	$ 6,221,576
Unproved	761,785	227,331
Total	10,213,198	6,448,907
Less accumulated depreciation, depletion and amortization	(3,057,742)	(2,480,261)
Net capitalized costs	$ 7,155,456	$ 3,968,646

Unproved properties not subject to amortization at December 31, 2004 and 2003 consisted mainly of leasehold acquired through corporate and significant oil and gas property acquisitions and through direct purchases of leasehold. We capitalized approximately $36.2 million, $13.0 million and $5.0 million of interest during 2004, 2003 and 2002, respectively, on significant investments in unproved properties that were not yet included in the amortization base of the full-cost pool. We will continue to evaluate our unevaluated properties; however, the timing of the ultimate evaluation and disposition of the properties has not been determined.

Costs Incurred in Oil and Gas Acquisition, Exploration and Development

Costs incurred in oil and gas property acquisition, exploration and development activities which have been capitalized are summarized as follows:

	Years Ended December 31,		
	2004	2003	2002
	($ in thousands)		
Acquisition of properties:			
Proved properties	$1,541,920	$1,110,077	$316,583
Unproved properties	570,495	198,394	14,000
Deferred income taxes	463,949	(4,903)	62,398
Development costs:			
Development drilling (a)	863,268	474,355	240,313
Leasehold acquisition costs	110,530	84,984	44,734
Asset retirement obligation and other (c)	41,924	54,657	2,541
Exploration costs:			
Exploratory drilling	128,635	103,424	89,422
Geological and geophysical costs (b)	55,618	42,736	25,819
Sales of oil and gas properties	(12,048)	(22,156)	(839)
Total	$3,764,291	$2,041,568	$794,971

(a) Includes capitalized internal cost of $45.4 million, $30.9 million and $21.3 million, respectively.
(b) Includes capitalized internal cost of $6.3 million, $4.6 million and $3.0 million, respectively.
(c) The 2003 amount includes $24.1 million of asset retirement costs recorded as a result of implementation of SFAS 143 effective January 1, 2003.

Results of Operations from Oil and Gas Producing Activities (unaudited)

Chesapeake's results of operations from oil and gas producing activities are presented below for 2004, 2003 and 2002. The following table includes revenues and expenses associated directly with our oil and gas producing activities. It does not include any interest costs and general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our oil and gas operations.

	Years Ended December 31,		
	2004	2003	2002
	($ in thousands)		
Oil and gas sales (a)	$1,936,176	$1,296,822	$ 568,187
Production expenses	(204,821)	(137,583)	(98,191)
Production taxes	(103,931)	(77,893)	(30,101)
Depletion and depreciation	(582,137)	(369,465)	(221,189)
Imputed income tax provision (b)	(376,303)	(270,515)	(87,482)
Results of operations from oil and gas producing activities	$ 668,984	$ 441,366	$ 131,224

(a) Includes $40.9 million, $10.5 million and $(87.3) million of unrealized gains (losses) on oil and gas derivatives for the years ended December 31, 2004, 2003 and 2002, respectively.
(b) The imputed income tax provision is hypothetical (at the effective income tax rate) and determined without regard to our deduction for general and administrative expenses, interest costs and other income tax credits and deductions, nor whether the hypothetical tax provision will be payable.

Oil and Gas Reserve Quantities (unaudited)

Independent petroleum engineers and Chesapeake's petroleum engineers have evaluated our proved reserves. The portion of the combined discounted future net revenues from our estimated proved reserves evaluated by each for 2004, 2003 and 2002 is presented below.

	Years Ended December 31,		
	2004	2003	2002
Netherland, Sewell & Associates, Inc.	25%	26%	20%
Lee Keeling and Associates, Inc.	23	17	23
Ryder Scott Company L.P.	12	31	20
LaRoche Petroleum Consultants, Ltd.	7	—	—
H.J. Gruy and Associates, Inc.	7	—	—
Miller and Lents, Ltd.	2	—	—
Williamson Petroleum Consultants, Inc	—	—	10
Internal petroleum engineers	24	26	27
	100%	100%	100%

The information is presented in accordance with regulations prescribed by the Securities and Exchange Commission. Chesapeake emphasizes that reserve estimates are inherently imprecise. Our reserve estimates were generally based upon extrapolation of historical production trends, analogy to similar properties and volumetric calculations. Accordingly, these estimates are expected to change, and such changes could be material and occur in the near term as future information becomes available.

Proved oil and gas reserves represent 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, i.e., prices and costs as of the date the estimate is made. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production responses that increased recovery will be achieved.

Presented below is a summary of changes in estimated reserves of Chesapeake for 2004, 2003 and 2002:

	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)
December 31, 2004			
Proved reserves, beginning of period	51,422	2,860,040	3,168,575
Extensions, discoveries and other additions	7,601	771,125	816,728
Revisions of previous estimates	6,109	108,863	145,518
Production	(6,764)	(322,009)	(362,593)
Sale of reserves-in-place	(102)	(3,329)	(3,940)
Purchase of reserves-in-place	29,694	959,299	1,137,463
Proved reserves, end of period	87,960	4,373,989	4,901,751
Proved developed reserves:			
Beginning of period	38,442	2,121,734	2,352,389
End of period	62,713	2,842,141	3,218,418
December 31, 2003			
Proved reserves, beginning of period	37,587	1,979,601	2,205,125
Extensions, discoveries and other additions	3,574	359,681	381,123
Revisions of previous estimates	1,329	48,388	56,365
Production	(4,665)	(240,366)	(268,356)
Sale of reserves-in-place	(183)	(9,626)	(10,723)
Purchase of reserves-in-place	13,780	722,362	805,041
Proved reserves, end of period	51,422	2,860,040	3,168,575
Proved developed reserves:			
Beginning of period	28,111	1,458,284	1,626,952
End of period	38,442	2,121,734	2,352,389
December 31, 2002			
Proved reserves, beginning of period	30,093	1,599,386	1,779,946
Extensions, discoveries and other additions	4,348	217,116	243,205
Revisions of previous estimates	3,189	70,359	89,493
Production	(3,466)	(160,682)	(181,478)
Sale of reserves-in-place	(24)	(1,003)	(1,146)
Purchase of reserves-in-place	3,447	254,425	275,105
Proved reserves, end of period	37,587	1,979,601	2,205,125
Proved developed reserves:			
Beginning of period	22,496	1,134,381	1,269,359
End of period	28,111	1,458,284	1,626,952

During 2004, Chesapeake acquired approximately 1,137 bcfe of proved reserves through purchases of oil and gas properties for consideration of $2,006 million (primarily in fifteen separate transactions of greater than $10 million each). We also sold 4 bcfe of proved reserves for consideration of approximately $12.0 million. During 2004, we recorded upward revisions of 146 bcfe to the December 31, 2003 estimates of our reserves. Approximately 5 bcfe of the upward revisions was caused by higher oil and gas prices at December 31, 2004. Higher prices extend the economic lives of the underlying oil and gas properties and thereby increase the estimated future reserves. The weighted average oil and gas wellhead prices used in computing our reserves were $39.91 per bbl and $5.65 per mcf at December 31, 2004.

During 2003, Chesapeake acquired approximately 805 bcfe of proved reserves through purchases of oil and gas properties for consideration of $1,105 million (primarily in nine separate transactions of greater than $10 million each). We also sold 11 bcfe of proved reserves for consideration of approximately $22.2 million. During 2003, we recorded upward revisions of 56 bcfe to the December 31, 2002 estimates of our reserves. Approximately 11.1 bcfe of the upward revisions was caused by higher oil and gas prices at December 31, 2003. Higher prices extend the economic lives of the underlying oil and gas properties and thereby increase the estimated future reserves. The weighted average oil and gas wellhead prices used in computing our reserves were $30.22 per bbl and $5.68 per mcf at December 31, 2003.

During 2002, Chesapeake acquired approximately 275 bcfe of proved reserves through purchases of oil and gas properties for consideration of $379 million (primarily in six separate transactions of greater than $10 million each). We also sold 1 bcfe of proved reserves for consideration of approximately $0.8 million. During 2002, we recorded upward revisions of 89 bcfe to the December 31, 2001 estimates of our reserves. Approximately 76 bcfe of the upward revisions was caused by higher oil and gas prices at December 31, 2002. Higher prices extend the economic lives of the underlying oil and gas properties and thereby increase the estimated future reserves. The weighted average oil and gas wellhead prices used in computing our reserves were $30.18 per bbl and $4.28 per mcf at December 31, 2002, compared to $18.82 per bbl and $2.51 per mcf at December 31, 2001.

Standardized Measure of Discounted Future Net Cash Flows (unaudited)

Statement of Financial Accounting Standards No. 69 prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. Chesapeake has followed these guidelines which are briefly discussed below.

Future cash inflows and future production and development costs are determined by applying year-end prices and costs to the estimated quantities of oil and gas to be produced. Actual future prices and costs may be materially higher or lower than the year-end prices and costs used. Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions. Estimated future income taxes are computed using current statutory income tax rates including consideration for the current tax basis of the properties and related carryforwards, giving effect to permanent differences and tax credits. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board and, as such, do not necessarily reflect our expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates reflect the valuation process.

The following summary sets forth our future net cash flows relating to proved oil and gas reserves based on the standardized measure prescribed in SFAS 69:

	December 31, 2004	December 31, 2003	December 31, 2002
	($ in thousands)		
Future cash inflows	$28,245,336[a]	$17,807,624[b]	$ 9,640,070[c]
Future production costs	(6,542,219)	(3,816,607)	(2,273,610)
Future development costs	(2,115,511)	(912,594)	(606,042)
Future income tax provisions	(5,663,575)	(3,827,408)	(1,867,315)
Net future cash flows	13,924,031	9,251,015	4,893,103
Less effect of a 10% discount factor	(6,278,492)	(3,924,262)	(2,059,185)
Standardized measure of discounted future net cash flows	$ 7,645,539	$ 5,326,753	$ 2,833,918
Discounted (at 10%) future net cash flows before income taxes	$10,504,390	$ 7,333,142	$ 3,717,645

(a) Calculated using weighted average prices of $39.91 per barrel of oil and $5.65 per mcf of gas.
(b) Calculated using weighted average prices of $30.22 per barrel of oil and $5.68 per mcf of gas.
(c) Calculated using weighted average prices of $30.18 per barrel of oil and $4.28 per mcf of gas.

The principal sources of change in the standardized measure of discounted future net cash flows are as follows:

	December 31, 2004	December 31, 2003	December 31, 2002
	($ in thousands)		
Standardized measure, beginning of period(a)	$ 5,326,753	$ 2,833,918	$1,460,973
Sales of oil and gas produced, net of production costs(b)	(1,741,438)	(1,088,184)	(431,116)
Net changes in prices and production costs	(730,020)	(2,364)	779,756
Extensions and discoveries, net of production and development costs	1,784,166	1,041,108	463,674
Changes in future development costs	33,284	74,719	32,812
Development costs incurred during the period that reduced future development costs	226,415	130,195	68,387
Revisions of previous quantity estimates	317,518	99,927	137,639
Purchase of reserves-in-place (c)	2,580,973	2,012,686	528,734
Sales of reserves-in-place (c)	(5,604)	(827)	(535)
Accretion of discount	733,314	371,765	164,667
Net change in income taxes	(852,462)	(1,122,661)	(698,033)
Changes in production rates and other	(27,360)	976,471	326,960
Standardized measure, end of period (a)	$ 7,645,539	$ 5,326,753	$2,833,918

(a) The discounted amounts related to cash flow hedges that would affect future net cash flows have not been included in any of the periods presented.
(b) Excluding gains (losses) on derivatives.
(c) In 2003, purchases and sales of reserves are shown net of the 9.9 bcfe which was acquired and immediately sold for $19 million.

12. Asset Retirement Obligations

Effective January 1, 2003, Chesapeake adopted SFAS 143, *Accounting for Asset Retirement Obligation.* This statement applies to obligations associated with the retirement of tangible, long-lived assets that result from the acquisition, construction and development of the assets.

We identified and estimated all of our asset retirement obligations for tangible, long-lived assets as of January 1, 2003. These obligations were for future plugging and abandonment costs for depleted oil and gas wells. Prior to the adoption of SFAS 143, we included an estimate of our asset retirement obligations related to our oil and gas properties in our calculation of oil and gas depreciation, depletion and amortization expense. Upon adoption of SFAS 143, we recorded the discounted fair value of our expected future obligations of $30.5 million, the cumulative effect of the change in accounting principle, as an increase to earnings of $2.4 million (net of income taxes) and an increase in net oil and gas properties of $34.3 million. The pro forma effect on prior periods' financial position and results of operations was not material.

The components of the change in our asset retirement obligations are shown below:

	Years ended December 31, 2004	2003
	($ in thousands)	
Asset retirement obligations, beginning balance	$48,812	$30,479
Additions and revisions	21,862	19,445
Settlements and disposals	(1,613)	(4,255)
Accretion expense	4,657	3,143
Asset retirement obligations, ending balance	$73,718	$48,812

13. Acquisitions and Divestitures

We completed the acquisition of Concho Resources Inc. in January 2004 to acquire oil and gas interests primarily in the Permian Basin and the Mid-Continent. We paid $420 million in cash for these assets, $10 million of which was paid in 2003. We also paid $12 million in employee severance and other transaction costs at closing. We recorded a $117 million deferred tax liability to reflect the tax effect of the cost in excess of the tax basis acquired. We completed a $425 million acquisition of privately-held Greystone Petroleum, LLC in June 2004 to acquire natural gas assets in the Ark-La-Tex region of northern Louisiana. We recorded a $40 million deferred tax liability to reflect the tax effect of the cost in excess of the tax basis acquired. We completed a $335 million acquisition of Bravo Natural Resources, Inc. in August 2004 to acquire oil and gas interests in the Anadarko Basin. We recorded a $174 million deferred tax liability to reflect the tax effect of the cost in excess of the tax basis acquired. We completed a $292 million acquisition of Hallwood Energy Corporation in December 2004 to acquire oil and gas interests in Johnson County, Texas. We recorded a $106 million deferred tax liability to reflect the tax effect of the cost in excess of the tax basis acquired. The assets of these entities were comprised principally of proved and unproved oil and gas properties.

Acquisitions were recorded using the purchase method of accounting and, accordingly, results of operations of these acquired activities and oil and gas properties have been included in Chesapeake's results of operations from the respective closing dates of the acquisitions. Had these acquisitions been completed at January 1, 2003, the pro forma effect on the results of operations for the years ended 2004 and 2003 would not have been material.

In addition to the acquisitions mentioned previously, we invested approximately $667 million (excluding $27 million of deferred taxes associated with certain properties) to acquire various other proved and unproved oil and gas properties during 2004. These properties are primarily located in the Mid-Continent region and were acquired through both corporate and asset acquisitions.

14. Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 2004 and 2003 are as follows ($ in thousands except per share data):

	Quarters Ended			
	March 31, 2004	June 30, 2004	September 30, 2004	December 31, 2004
Total revenues	$563,129	$574,292	$629,796	$942,051
Gross profit(a)	228,044	179,280	199,165	385,846
Net income	112,590(b)	97,155	96,872	208,538(c)
Net earnings per common share:				
Basic	$ 0.44	$ 0.36	$ 0.33	$ 0.59
Diluted	$ 0.38	$ 0.30	$ 0.29	$ 0.52

	Quarters Ended			
	March 31, 2003	June 30, 2003	September 30, 2003	December 31, 2003
Total revenues	$376,327	$429,815	$454,549	$456,741
Gross profit(a)	150,952	169,902	182,741	171,660
Net income before cumulative effect of accounting change, net of tax	71,120	82,240	87,859	69,373
Cumulative effect of accounting change, net of tax	2,389	—	—	—
Net income	$ 73,509	$ 82,240	$ 87,859	$ 69,373(d)
Net earnings per common share – basic:				
Income before cumulative effect of accounting change	$ 0.34	$ 0.36	$ 0.38	$ 0.29
Cumulative effect of accounting change	0.01	—	—	—
	$ 0.35	$ 0.36	$ 0.38	$ 0.29
Net earnings per share – assuming dilution:				
Income before cumulative effect of accounting change	$ 0.31	$ 0.31	$ 0.33	$ 0.25
Cumulative effect of accounting change	0.01	—	—	—
	$ 0.32	$ 0.31	$ 0.33	$ 0.25

(a) Total revenue less total operating costs.
(b) Includes a pre-tax loss on repurchases and exchanges of debt of $6.9 million.
(c) Includes a pre-tax loss on repurchases and exchanges of debt of $17.6 million.
(d) Includes a pre-tax loss on repurchases and exchanges of debt of $20.8 million.

15. Recently Issued Accounting Standards

During 2004, the Financial Accounting Standards Board and the Securities and Exchange Commission issued the following standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

In September 2004, the FASB finalized FASB Staff Position, FSP SFAS 142-2, *Application of FASB Statement No. 142 to Oil and Gas Producing Entities.* The FSP clarified that an exception in SFAS 142 includes the balance sheet classification and disclosures for drilling and mineral rights of oil and gas producing entities.

The FASB staff acknowledged that the existing accounting framework for oil and gas producers is based on the level of established reserves, not whether an asset is tangible. The FSP confirms Chesapeake's historical treatment of these costs.

In September 2004, the Securities and Exchange Commission issued Staff Accounting Bulletin 106 which summarizes the views of the staff regarding the application of SFAS 143, *Accounting for Asset Retirement Obligations*, by oil and gas producing companies following the full cost accounting method. SAB 106 was effective in the fourth quarter of 2004. Implementation of this bulletin did not have a material effect on our financial statements.

In September 2004, the Emerging Issues Task Force issued EITF No. 04-8, *The Effect of Contingently Convertible Instruments on Diluted Earnings per Share.* EITF No. 04-8 provides new guidance on when the dilutive effect of contingently convertible securities with a market price trigger should be included in diluted EPS. The guidance in EITF No. 04-8 is effective for all periods ending after December 15, 2004 and Chesapeake has complied by retrospectively restating previous reported EPS. The effect of this pronouncement on diluted EPS is more fully described in note 1 of the notes to our consolidated financial statements included in Item 8.

In December 2004, the Financial Accounting Standards Board issued SFAS 123(R), *Share-Based Payment*, a revision of SFAS 123, accounting for stock-based compensation. This statement establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services by requiring a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. That cost will be recognized over the period during which an employee is required to provide service in exchange for the award. The fair value of employee stock options will be estimated using option-pricing models. Excess tax benefits will be recognized as an addition to paid-in capital. Cash retained as a result of those excess tax benefits will be presented in the statement of cash flows as financing cash inflows. The write-off of deferred tax assets relating to unrealized tax benefits associated with recognized compensation cost will be recognized as income tax expense unless there are excess tax benefits from previous awards remaining in paid-in capital to which it can be offset. This statement is effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005.

16. Subsequent Events

On January 28, 2005 we amended and restated our bank credit facility, increasing the borrowing base to $1.25 billion and extending the maturity to January 2010.

In January 2005, we purchased $11.0 million principal amount of our 8.375% Senior Notes due 2008 for $12.0 million, including $0.8 million of premium and $0.2 million of accrued interest.

On February 1, 2005, we acquired Mid-Continent and Ark-La-Tex natural gas and oil assets through the purchase of the stock of BRG Petroleum Corporation and the acquisition of various other partnership interests for cash consideration of approximately $325 million, of which $16.3 million was paid in 2004.

Schedule II

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS
($ in thousands)

Description	Balance at Beginning of Period	Additions: Charged To Expense	Additions: Charged To Other Accounts	Deductions	Balance at End of Period
December 31, 2004:					
Allowance for doubtful accounts	$2,669	$ 975	$1,004	$ —	$4,648
Valuation allowance for deferred tax assets	$6,805	$ —	$ —	$6,805	$ —
December 31, 2003:					
Allowance for doubtful accounts	$1,433	$ 156	$1,202	$ 122	$2,669
Valuation allowance for deferred tax assets	$2,441	$4,364[(a)]	$ —	$ —	$6,805
December 31, 2002:					
Allowance for doubtful accounts	$ 947	$ 315	$ 171	$ —	$1,433
Valuation allowance for deferred tax assets	$2,441	$ —	$ —	$ —	$2,441

(a) As of December 31, 2004, we determined that it is more likely than not that $6.8 million of the net deferred tax assets related to net operating losses generated by Louisiana properties would be realized due to acquisitions which occurred in 2004. Therefore, the $6.8 million valuation allowance was reversed.

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

Not applicable.

ITEM 9A. ***Controls and Procedures***

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed by Chesapeake in reports filed or submitted by it under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. As of December 31, 2004, we carried out an evaluation, under the supervision and with the participation of Chesapeake management, including Chesapeake's Chief Executive Officer and Chief Financial Officer of the effectiveness of the design and operation of Chesapeake's disclosure controls and procedures pursuant to Securities Exchange Act Rule 13a-15(b). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective to ensure that information required to be disclosed by Chesapeake is accumulated and communicated to Chesapeake management, including Chesapeake's Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Controls

No changes in the company's internal control over financial reporting occurred during the quarter ended December 31, 2004 that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Management's report on internal control over financial reporting and the attestation report of our independent registered public accounting firm are included in Item 8 of this report.

ITEM 9B. ***Other Information***

The following disclosure would otherwise have been filed on Form 8-K under the caption Item 1.01. Entry into a Material Definitive Agreement:

On January 3, 2005, the Compensation Committee of the Board of Directors of Chesapeake set the 2005 annual base salaries of the named executive officers at $900,000 for Aubrey K. McClendon, $900,000 for Tom L. Ward, $530,000 for Marcus C. Rowland, $425,000 for Martha A. Burger and $320,000 for Michael A. Johnson. In addition, the Committee awarded cash bonuses to the named executive officers, payable on January 15, 2005, of $575,000 for Aubrey K. McClendon, $575,000 for Tom L. Ward, $325,000 for Marcus C. Rowland, $215,000 for Martha A. Burger and $120,000 for Michael A. Johnson.

PART III

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

The information called for by this Item 10 is incorporated herein by referenced to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 29, 2005.

ITEM 11. ***Executive Compensation***

The information called for by this item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 29, 2005.

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

The information called for by this item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 29, 2005.

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

The information called for by this item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 29, 2005.

ITEM 14. ***Principal Accounting Fees and Services***

The information called for by this item 14 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 29, 2005.

PART IV

ITEM 15. *Exhibits, Financial Statement Schedules*

(a) The following documents are filed as part of this report:

1. *Financial Statements.* Chesapeake's consolidated financial statements are included in Item 8 of this report. Reference is made to the accompanying Index to Financial Statements.

2. *Financial Statement Schedules.* Schedule II is included in Item 8 of this report with our consolidated financial statements. No other financial statement schedules are applicable or required.

3. *Exhibits.* The following exhibits are filed herewith pursuant to the requirements of Item 601 of Regulation S-K:

Exhibit Number	Description
3.1*	—Chesapeake's Restated Certificate of Incorporation, together with the Certificates of Designation for the 6.0% Cumulative Convertible Preferred Stock, the 5.0% Cumulative Convertible Preferred Stock, the 4.125% Cumulative Convertible Preferred Stock and the Series A Junior Participating Preferred Stock.
3.2	—Chesapeake's Amended and Restated Bylaws. Incorporated herein by reference to Exhibit 3.2 of Chesapeake's annual report on Form 10-K for the year ended December 31, 2003.
4.1	—Indenture dated as of May 27, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York, as Trustee, with respect to 7.5% senior notes due 2014. Incorporated herein by reference to Exhibit 4.1 to Chesapeake's registration statement on Form S-4 (No. 333-116555). First Supplemental Indenture dated as of August 30, 2004. Incorporated herein by reference to Exhibit 4.11.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004. Second Supplemental Indenture dated as of September 27, 2004. Incorporated herein by reference to Exhibit 4.11.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
4.1.1*	—Third Supplemental Indenture dated as of January 31, 2005 to Indenture dated as of May 27, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to the 7.50% senior notes due 2014.
4.2	—Indenture dated as of August 2, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York, as Trustee, with respect to 7.0% senior notes due 2014. Incorporated herein by reference to Exhibit 4.1 to Chesapeake's registration statement on Form S-4 (No. 333-118378). First Supplemental Indenture dated as of August 30, 2004. Incorporated herein by reference to Exhibit 4.12.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004. Second Supplemental Indenture dated as of September 27, 2004. Incorporated herein by reference to Exhibit 4.12.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
4.2.1*	—Third Supplemental Indenture dated as of January 31, 2005 to Indenture dated as of May 27, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to the 7.00% senior notes due 2014.
4.3	—Indenture dated as of April 6, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 8.125% Senior Notes due 2011. Incorporated herein by reference to Exhibit 4.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2001. Supplemental Indenture dated May 14, 2001. Incorporated herein by reference to

Exhibit Number	Description
	Exhibit 4.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2001. Second Supplemental Indenture dated September 12, 2001. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Third Supplemental Indenture dated October 1, 2001. Incorporated herein by reference to Exhibit 4.3.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Fourth Supplemental Indenture dated December 17, 2001. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's registration statement on Form S-3 (No. 333-76546). Fifth Supplemental Indenture dated as of June 28, 2002. Incorporated herein by reference to Exhibit 4.3.2 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Sixth Supplemental Indenture dated July 8, 2002. Incorporated herein by reference to Exhibit 4.3.3 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Seventh Supplemental Indenture dated as of February 14, 2003. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's annual report on Form 10-K/A for the year ended December 31, 2002. Eighth Supplemental Indenture dated as of May 1, 2003. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003. Ninth Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003 Tenth Supplemental Indenture dated as of March 5, 2004. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2004. Eleventh Supplemental Indenture dated as of August 30, 2004. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004. Twelfth Supplemental Indenture dated as of September 27, 2004. Incorporated herein by reference to Exhibit 4.3.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
4.3.1*	—Thirteenth Supplemental Indenture dated as of January 31, 2005 to Indenture dated as of April 6, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to the 8.125% senior notes due 2011.
4.4	—Indenture dated as of November 5, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to 8.375% Senior Notes due 2008. Incorporated herein by reference to Exhibit 4.16 to Chesapeake's registration statement on Form S-4 (No. 333-74584). First Supplemental Indenture dated December 17, 2001. Incorporated herein by reference to Exhibit 4.16.1 to Chesapeake's registration statement on Form S-3 (No. 333-76546). Second Supplemental Indenture dated as of June 28, 2002. Incorporated herein by reference to Exhibit 4.4.2 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Third Supplemental Indenture dated as of July 8, 2002. Incorporated herein by reference to Exhibit 4.4.3 to Chesapeake's registration statement on Form S-4 (No. 333-99289). Fourth Supplemental Indenture dated as of February 14, 2003.Incorporated herein by reference to Exhibit 4.4.1 to Chesapeake's annual report on Form 10-K/A for the year ended December 31, 2002. Fifth Supplemental Indenture dated as of May 1, 2003. Incorporated herein by reference to Exhibit 4.4.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003. Sixth Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Exhibit 4.4.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003. Seventh Supplemental Indenture dated as of March 5, 2004. Incorporated herein by reference to Exhibit 4.4.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2003. Eighth Supplemental Indenture dated as of August 30, 2004. Incorporated herein by reference to Exhibit 4.4.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004. Ninth Supplemental Indenture dated as of September 27, 2004. Incorporated herein by reference to Exhibit 4.4.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.

Exhibit Number	Description
4.4.1*	—Tenth Supplemental Indenture dated December 21, 2004 to Indenture dated as of November 5, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to 8.375% Senior Notes due 2008.
4.4.2*	—Eleventh Supplemental Indenture dated January 31, 2005 to Indenture dated as of November 5, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to 8.375% Senior Notes due 2008.
4.5	—Indenture dated as of August 12, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York, as Trustee, with respect to its 9.0% Senior Notes due 2012. Incorporated herein by reference to Exhibit 4.14 to Chesapeake's registration statement on Form S-4 (No. 333-99289). First Supplemental Indenture dated as of February 14, 2003.Incorporated herein by reference to Exhibit 4.5.1 to Chesapeake's annual report on Form 10-K/A for the year ended December 31, 2002. Second Supplemental Indenture dated May 1, 2003. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003. Third Supplemental Indenture dated August 15, 2003. Incorporated herein by reference to Exhibit 4.5.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003. Fourth Supplemental Indenture dated as of March 5, 2004. Incorporated herein by reference to Exhibit 4.5.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2003. Fifth Supplemental Indenture dated as of August 30, 2004. Incorporated herein by reference to Exhibit 4.5.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004. Sixth Supplemental Indenture dated as of September 27, 2004. Incorporated herein by reference to Exhibit 4.5.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
4.5.1*	—Seventh Supplemental Indenture dated January 31, 2005 to Indenture dated as of August 12, 2002 among Chesapeake, as issuer, subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to 9.0% Senior Notes due 2012.
4.6	—Indenture dated as of December 20, 2002 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York, as Trustee, with respect to our 7.75% Senior Notes due 2015. Incorporated herein by reference to Exhibit 4.5 to Chesapeake's registration statement on Form S-4 (No. 333-102445) First Supplemental Indenture dated as of February 14, 2003. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's report on Form 10-K/A for the year ended December 31, 2002. Second Supplemental Indenture dated as of May 1, 2003. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003. Third Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003. Fourth Supplemental Indenture dated as of March 5, 2004. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2003. Fifth Supplemental Indenture dated as of August 30, 2004. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004. Sixth Supplemental Indenture dated as of September 27, 2004. Incorporated herein by reference to Exhibit 4.6.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
4.6.1*	—Seventh Supplemental Indenture dated January 31, 2005 to Indenture dated as of December 20, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to 7.75% Senior Notes due 2015.
4.7	—Agreement to furnish copies of unfiled long-term debt instruments. Incorporated herein by reference to Chesapeake's transition report on Form 10-K for the six months ended December 31, 1997.

Exhibit Number	Description
4.8	—Fifth Amended and Restated Credit Agreement, dated as of January 28, 2005, among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership, as Borrower, Bank of America, N.A. and Union Bank of California, N.A., as Co-Administrative Agents, Union Bank of California, N.A. as Administrative Paying, Receiving and Collateral Agent, BNP Paribas, Calyon New York Branch and SunTrust Bank as Co-Documentation Agents and the several lenders from time to time parties thereto. Incorporated herein by reference to Exhibit 4.8 to Chesapeake's current report on Form 8-K dated February 2, 2005.
4.9	—Indenture dated as of March 5, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York, as Trustee, with respect to 7.5% Senior Notes due 2013. First Supplemental Indenture dated as of May 1, 2003. Incorporated herein by reference to Exhibit 4.7.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2003. Second Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Exhibit 4.7.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003. Third Supplemental Indenture dated as of March 5, 2004. Incorporated herein by reference to Exhibit 4.9.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2003. Fourth Supplemental Indenture dated as of August 30, 2004. Incorporated herein by reference to Exhibit 4.9.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004. Fifth Supplemental Indenture dated as of September 27, 2004. Incorporated herein by reference to Exhibit 4.9.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
4.9.1*	—Sixth Supplemental Indenture dated January 31, 2005 to Indenture dated as of March 5, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to 7.5% Senior Notes due 2013.
4.10	—Indenture dated as of November 26, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York, as Trustee, with respect to 6.875% senior notes due 2016. Incorporated herein by reference to Exhibit 4.2 to Chesapeake's registration statement on Form S-4/A (No. 333-110668). First Supplemental Indenture dated as of March 5, 2004. Incorporated herein by reference to Exhibit 4.10.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2003. Second Supplemental Indenture dated as of August 30, 2004. Incorporated herein by reference to Exhibit 4.10.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004. Third Supplemental Indenture dated as of September 27, 2004. Incorporated herein by reference to Exhibit 4.10.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
4.10.1*	—Fourth Supplemental Indenture dated January 31, 2005 to Indenture dated as of November 26, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to 6.875% senior notes due 2016.
4.11	—Indenture dated as of December 8, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.375% senior notes due 2015. Incorporated herein by reference to Exhibit 4.1 to Chesapeake's current report on Form 8-K dated December 14, 2004.
4.11.1*	—First Supplemental Indenture dated January 31, 2005 to Indenture dated as of December 8, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.375% senior notes due 2015.

Exhibit Number	Description
4.15	—Warrant Registration Rights Agreement dated as of April 21, 1998 among Gothic Energy Corporation and purchasers of units consisting of its 14 1⁄8% senior secured discount notes due 2006 and warrants to purchase its common stock. Incorporated herein by reference to Exhibit 4.15 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2000.
10.1.1†	—Chesapeake's 2003 Stock Incentive Plan. Incorporated herein by reference to Exhibit A to Chesapeake's definitive proxy statement for its 2003 annual meeting of shareholders filed April 17, 2003.
10.1.1.1†	—Form of Restricted Stock Award Agreement for Chesapeake's 2003 Stock Incentive Plan. Incorporated herein by reference to Exhibit 10.1.14.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.2†	—Chesapeake's 1992 Nonstatutory Stock Option Plan, as Amended. Incorporated herein by reference to Exhibit 10.1.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended December 31, 1996.
10.1.3†	—Chesapeake's 1994 Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.3 to Chesapeake's quarterly report on Form 10-Q for the quarter ended December 31, 1996.
10.1.4†	—Chesapeake's 1996 Stock Option Plan. Incorporated herein by reference to Exhibit B to Chesapeake's definitive proxy statement for its 1996 annual meeting of shareholders.
10.1.4.1†	—Form of Incentive Stock Option Agreement for Chesapeake's 1996 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.4.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.4.2†	—Form of Nonqualified Stock Option Agreement for Chesapeake's 1996 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.4.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.5†	—Chesapeake's 1999 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.5 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 1999.
10.1.5.1†	—Form of Nonqualified Stock Option Agreement for Chesapeake's 1999 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.5.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.6†	—Chesapeake's 2000 Employee Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2000.
10.1.6.1†	—Form of Nonqualified Stock Option Agreement for Chesapeake's 2000 Employee Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2000.
10.1.7†	—Chesapeake's 2000 Executive Officer Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.7 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2000.
10.1.8†	—Chesapeake's 2001 Stock Option Plan. Incorporated herein by reference to Exhibit B to Chesapeake's definitive proxy statement for its 2001 annual meeting of shareholders filed April 30, 2001.
10.1.8.1†	—Form of Incentive Stock Option Agreement for Chesapeake's 2001 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.8.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.

Exhibit Number	Description
10.1.8.2†	—Form of Nonqualified Stock Option Agreement for Chesapeake's 2001 Stock Option Plan and 2001 Nonqualified Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.8.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.9†	—Chesapeake's 2001 Executive Officer Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.9 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2001.
10.1.10†	—Chesapeake's 2001 Nonqualified Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.10 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2001.
10.1.11†	—Chesapeake's 2002 Stock Option Plan. Incorporated herein by reference to Exhibit A to Chesapeake's definitive proxy statement for its 2002 annual meeting of shareholders filed April 29, 2002.
10.1.11.1†	—Form of Incentive Stock Option Agreement for Chesapeake's 2002 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.11.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.11.2†	—Form of Nonqualified Stock Option Agreement for Chesapeake's 2002 Stock Option Plan and 2002 Nonqualified Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.11.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.12†	—Chesapeake's 2002 Non-Employee Director Stock Option Plan. Incorporated herein by reference to Exhibit B to Chesapeake's definitive proxy statement for its 2002 annual meeting of shareholders filed April 29, 2002.
10.1.12.1†	—Form of Stock Option Agreement for Chesapeake's 2002 Non-Employee Director Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.12.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.13†	—Chesapeake's 2002 Nonqualified Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.11 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2002.
10.1.14†	—Chesapeake's 2003 Stock Award Plan for Non-Employee Directors. Incorporated herein by reference to Exhibit 10.1.14 to Chesapeake's annual report of Form 10-K/A for the year ended December 31, 2002.
10.1.15†	—Chesapeake Energy Corporation 401(k) Make-Up Plan. Incorporated herein by reference to Exhibit 10.1.15 to Chesapeake's annual report on Form 10-K/A for the year ended December 31, 2002.
10.1.15.1†*	—Chesapeake Energy Corporation 401(k) Make-Up Plan - 2005.
10.1.16†	—Chesapeake Energy Corporation Deferred Compensation Plan. Incorporated herein by reference to Exhibit 10.1.16 to Chesapeake's annual report on Form 10-K/A for the year ended December 31, 2002.
10.1.16.1†*	—Chesapeake Energy Corporation Deferred Compensation Plan - 2005.
10.1.17†	—Form of Stock Option Grant Notice. Incorporated herein by reference to Exhibit 10.1.15 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.2.1†	—Third Amended and Restated Employment Agreement dated as of January 1, 2004, between Aubrey K. McClendon and Chesapeake Energy Corporation.

Exhibit Number	Description
10.2.2†	—Third Amended and Restated Employment Agreement dated as of January 1, 2004, between Tom L. Ward and Chesapeake Energy Corporation.
10.2.3†	—Amended and Restated Employment Agreement dated as of July 1, 2003 between Marcus C. Rowland and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.3 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.
10.2.8†	—Employment Agreement dated as of July 1, 2003 between Michael A. Johnson and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.8 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.
10.2.9†	—Employment Agreement dated as of July 1, 2003 between Martha A. Burger and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.9 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2003.
10.3†	—Form of Indemnity Agreement for officers and directors of Chesapeake and its subsidiaries. Incorporated herein by reference to Exhibit 10.30 to Chesapeake's registration statement on Form S-1 (No. 33-55600).
10.4†*	—Non-Employee Director Compensation.
10.5†*	—Named Executive Officer Compensation
10.6	—Rights Agreement dated July 15, 1998 between Chesapeake and UMB Bank, N.A., as Rights Agent. Incorporated herein by reference to Exhibit 1 to Chesapeake's registration statement on Form 8-A filed July 16, 1998. Amendment No. 1 dated September 11, 1998. Incorporated herein by reference to Exhibit 10.3 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 1998.
12*	—Ratios of Earnings to Fixed Charges and Preferred Dividends.
21*	—Subsidiaries of Chesapeake.
23.1*	—Consent of Pricewaterhouse Coopers, LLP
23.2*	—Consent of Ryder Scott Company L.P.
23.3*	—Consent of Lee Keeling and Associates, Inc.
23.4*	—Consent of Netherland, Sewell & Associates, Inc.
23.5*	—Consent of LaRoche Petroleum Consultants, Ltd.
23.6*	—Consent of H.J. Gruy and Associates, Inc.
23.7*	—Consent of Miller and Lents, Ltd.
31.1*	—Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	—Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	—Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	—Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

† Management contract or compensatory plan or arrangement.

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.

CHESAPEAKE ENERGY CORPORATION

By /s/ AUBREY K. MCCLENDON

Aubrey K. McClendon
Chairman of the Board and
Chief Executive Officer

Date: March 8, 2005

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Capacity	Date
/s/ AUBREY K. MCCLENDON **Aubrey K. McClendon**	Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)	March 8, 2005
/s/ TOM L. WARD **Tom L. Ward**	President, Chief Operating Officer and Director	March 8, 2005
/s/ MARCUS C. ROWLAND **Marcus C. Rowland**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 8, 2005
/s/ MICHAEL A. JOHNSON **Michael A. Johnson**	Senior Vice President—Accounting, Controller and Chief Accounting Officer (Principal Accounting Officer)	March 8, 2005
/s/ FRANK KEATING **Frank Keating**	Director	March 8, 2005
/s/ BREENE M. KERR **Breene M. Kerr**	Director	March 8, 2005
/s/ CHARLES T. MAXWELL **Charles T. Maxwell**	Director	March 8, 2005
/s/ DON NICKLES **Don Nickles**	Director	March 8, 2005
/s/ SHANNON T. SELF **Shannon T. Self**	Director	March 8, 2005
/s/ FREDERICK B. WHITTEMORE **Frederick B. Whittemore**	Director	March 8, 2005