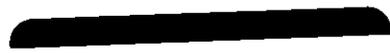


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Chesapeake Energy Corporation 2006 Annual Report

At A Glance

Chesapeake Energy is the third-largest independent producer of natural gas in the U.S. and the seventh-largest overall. Headquartered in Oklahoma City, the company's operations are focused on exploratory and developmental drilling and corporate and property acquisitions in the Mid-Continent, Fort Worth Barnett Shale, Appalachian Basin, Fayetteville Shale, South Texas, Permian Basin, Delaware Basin, Ark-La-Tex and Texas Gulf Coast regions of the United States. At year-end 2006, Chesapeake owned interests in approximately 35,000 producing wells and had proved reserves of 9.0 trillion cubic feet equivalent, of which 93% were natural gas.

Our New Logo



Chesapeake's new logo is an evolution of the logo we adopted seven years ago and updates our message in two important ways. First, the flame and the font have been modernized and more significantly, we have introduced a green element to our logo that communicates both the environmental attractiveness of natural gas and Chesapeake's heightened environmental awareness.

Some of the great public policy debates of the next 10 years will focus on how we should meet America's growing need for more electricity. Presently, coal meets 52% of our electricity needs, nuclear 21%, natural gas 21% and

hydro, wind and other renewables about 6%. It is imperative for the continued prosperity of our company and industry that natural gas be seen as the preferred solution to meeting the twin challenges of generating more electricity in the years ahead while at the same time reducing greenhouse gas emissions.

Chesapeake's new logo communicates our belief that the company's vast reserves of natural gas can help solve the environmental challenges of the years ahead. We are on the right side of history in the climate change debate and we hope you like our new logo and the message it conveys.

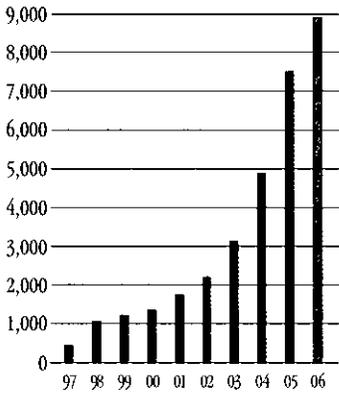
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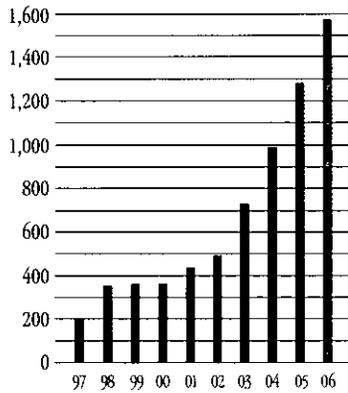
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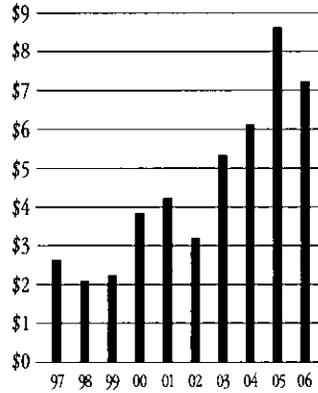
Proved Reserves Growth
Bcfe at end of year



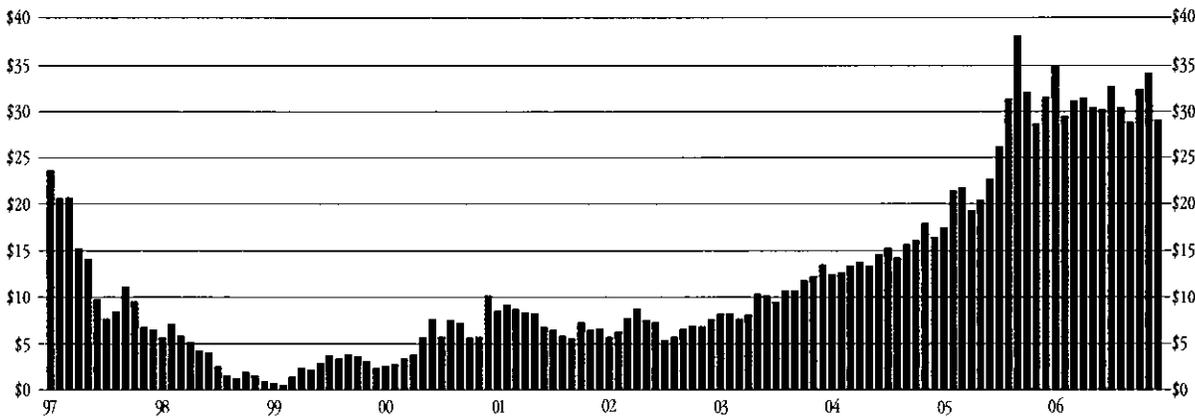
Production Growth
Average mmmcf per day for year



Natural Gas Prices
Average yearly NYMEX, \$ per mmbtu

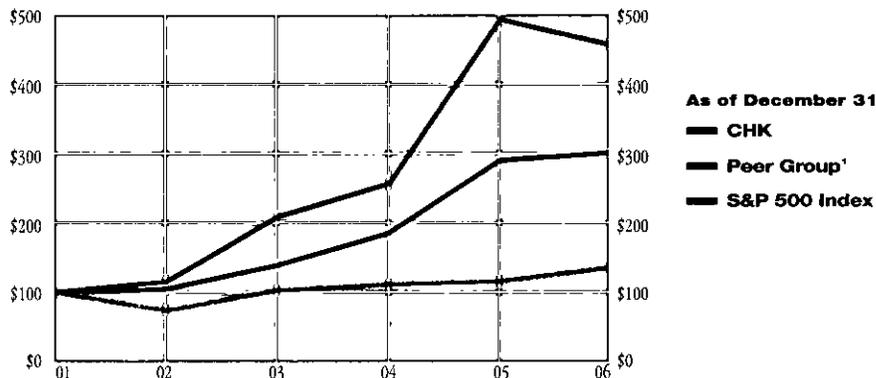


Chesapeake's Stock Price At month end



Chesapeake's Five-Year Common Stock Performance

The adjacent graph compares the performance of our common stock to a group of peer companies and the S&P 500 Index for the past five years. The graph assumes an investment of \$100 on December 31, 2001, the reinvestment of all dividends and shows the value of the investment at the end of each year.



¹The 2006 peer group was comprised of Anadarko Petroleum Corporation, Apache Corporation, Cabot Oil & Gas Corporation, XTO Energy, Inc., Devon Energy Corporation, EDG Resources, Inc., Forest Oil Corporation, Newfield Exploration Company, Noble Energy, Inc., Occidental Petroleum Corporation, Pioneer Natural Resources Company, Pogo Producing Co., Quicksilver Resources, Inc., Range Resources Corporation, Southwestern Energy Company and St. Mary Land & Exploration Company. Burlington Resources, Inc. and Kerr McGee Corporation are not included in the peer group in 2006 due to their acquisitions by ConocoPhillips and Anadarko Petroleum Corporation, respectively.

CHK 2006 Fact 1

Our stock price has increased 2,100% since Chesapeake's IPO 14 years ago

CHK 2006 Fact 2

We increased our average daily production 23% to 1,585 mmmcf from 1,284 mmmcf in 2005

CHK 2006 Fact 3

We increased our proved reserves 19% to 9.0 tcf from 7.5 tcf in 2005 through both acquisitions and the drillbit

Six Months Ended December 31					Years Ended June 30				
2001	2000	1999	1998	1997	1997	1996	1995	1994	1993
\$ 820,318	\$ 470,170	\$ 280,445	\$ 256,887	\$ 95,657	\$ 192,920	\$ 110,849	\$ 56,983	\$ 22,404	\$ 11,602
148,733	157,782	74,501	121,059	58,241	76,172	34,742	8,836	6,439	5,526
\$ 969,051	\$ 627,952	\$ 354,946	\$ 377,946	\$ 153,898	\$ 269,092	\$ 145,591	\$ 65,819	\$ 28,843	\$ 17,128
75,374	50,085	46,298	51,202	7,560	11,445	6,340	3,379	2,141	2,890
33,010	24,840	13,264	8,295	2,534	3,662	1,963	877	1,506	—
14,449	13,177	13,477	19,918	5,847	8,802	4,828	3,578	3,135	3,620
144,373	152,309	71,533	119,008	58,227	75,140	32,347	7,747	5,199	3,653
181,565	108,772	102,854	154,720	62,822	107,046	54,056	27,175	10,012	4,741
—	—	—	881,000	110,000	236,000	—	—	—	1,286
448,771	349,183	247,426	1,234,143	246,990	442,095	99,534	42,756	21,993	16,190
520,280	278,769	107,520	(856,197)	(93,092)	(173,003)	46,057	23,063	6,850	938
2,877	3,649	8,562	3,926	78,966	11,223	3,831	1,524	981	880
(98,321)	(86,256)	(81,052)	(68,249)	(17,448)	(18,550)	(13,679)	(6,627)	(2,676)	(2,282)
(63,138)	—	—	(13,334)	—	(6,620)	—	—	—	—
(158,582)	(82,607)	(72,490)	(77,657)	61,518	(13,947)	(9,848)	(5,103)	(1,695)	(1,402)
361,698	196,162	35,030	(933,854)	(31,574)	(186,950)	36,209	17,960	5,155	(464)
3,565	—	—	—	—	—	—	—	—	—
140,727	(259,408)	1,764	—	—	(3,573)	12,854	6,299	1,250	(99)
217,406	455,570	33,266	(933,854)	(31,574)	(183,377)	23,355	11,661	3,905	(365)
—	—	—	—	—	—	—	—	—	—
\$ 217,406	\$ 455,570	\$ 33,266	\$ (933,854)	\$ (31,574)	\$ (183,377)	\$ 23,355	\$ 11,661	\$ 3,905	\$ (365)
(2,050)	(8,484)	(16,711)	(12,077)	—	—	—	—	—	(385)
—	6,574	—	—	—	—	—	—	—	—
\$ 215,356	\$ 453,660	\$ 16,555	\$ (945,931)	\$ (31,574)	\$ (183,377)	\$ 23,355	\$ 11,661	\$ 3,905	\$ (750)
\$ 1.33	\$ 3.52	\$ 0.17	\$ (9.97)	\$ (0.45)	\$ (2.79)	\$ 0.43	\$ 0.22	\$ 0.08	\$ (0.02)
—	—	—	—	—	—	—	—	—	—
\$ 1.33	\$ 3.52	\$ 0.17	\$ (9.97)	\$ (0.45)	\$ (2.79)	\$ 0.43	\$ 0.22	\$ 0.08	\$ (0.02)
\$ 1.25	\$ 3.01	\$ 0.16	\$ (9.97)	\$ (0.45)	\$ (2.79)	\$ 0.40	\$ 0.21	\$ 0.08	\$ (0.02)
—	—	—	—	—	—	—	—	—	—
\$ 1.25	\$ 3.01	\$ 0.16	\$ (9.97)	\$ (0.45)	\$ (2.79)	\$ 0.40	\$ 0.21	\$ 0.08	\$ (0.02)
\$ 478,098	\$ 314,640	\$ 145,022	\$ 94,639	\$ 139,157	\$ 84,089	\$ 120,972	\$ 54,731	\$ 19,423	\$ (1,499)
\$ 442,924	\$ 305,804	\$ 138,727	\$ 117,500	\$ 67,872	\$ 161,140	\$ 88,431	\$ 45,903	\$ 15,527	\$ 4,404
—	—	—	—	—	—	—	—	—	—
\$ 2,286,768	\$ 1,440,426	\$ 850,533	\$ 812,615	\$ 952,784	\$ 949,068	\$ 572,335	\$ 276,693	\$ 125,690	\$ 78,707
1,329,453	944,845	964,097	919,076	508,992	508,950	268,431	145,754	47,878	14,051
\$ 767,407	\$ 313,232	\$ (217,544)	\$ (248,568)	\$ 280,206	\$ 286,889	\$ 177,767	\$ 44,975	\$ 31,260	\$ 31,432
—	—	—	—	—	—	—	—	—	—
1,779,946	1,354,813	1,205,595	1,091,348	448,474	403,004	424,775	242,505	141,992	137,495
\$ 1,646,667	\$ 6,046,028	\$ 1,089,496	\$ 660,991	\$ 466,509	\$ 437,386	\$ 547,016	\$ 188,137	\$ 141,249	\$ 141,665
\$ 2.51	\$ 10.12	\$ 2.25	\$ 1.68	\$ 2.29	\$ 2.12	\$ 2.41	\$ 1.60	\$ 1.98	\$ 2.43
\$ 18.82	\$ 26.41	\$ 24.72	\$ 10.48	\$ 17.62	\$ 18.38	\$ 20.90	\$ 17.41	\$ 18.27	\$ 18.71
144,171	115,771	108,610	94,421	27,326	62,005	51,710	25,114	6,927	2,677
2,880	3,068	4,147	5,976	1,857	2,770	1,413	1,139	537	276
161,451	134,179	133,492	130,277	38,468	78,625	60,190	31,947	10,152	4,333
\$ 4.56	\$ 3.50	\$ 2.10	\$ 1.97	\$ 2.49	\$ 2.45	\$ 1.84	\$ 1.78	\$ 2.21	\$ 2.68
\$ 0.47	\$ 0.37	\$ 0.35	\$ 0.39	\$ 0.20	\$ 0.15	\$ 0.11	\$ 0.11	\$ 0.21	\$ 0.67
\$ 0.20	\$ 0.19	\$ 0.10	\$ 0.06	\$ 0.07	\$ 0.05	\$ 0.03	\$ 0.03	\$ 0.15	—
\$ 0.09	\$ 0.10	\$ 0.10	\$ 0.15	\$ 0.15	\$ 0.11	\$ 0.08	\$ 0.11	\$ 0.31	\$ 0.84
\$ 1.12	\$ 0.81	\$ 0.77	\$ 1.19	\$ 1.63	\$ 1.36	\$ 0.90	\$ 0.85	\$ 0.99	\$ 1.09
677	462	424	481	360	362	344	325	250	150
—	—	—	\$ 0.04	\$ 0.04	\$ 0.02	—	—	—	—
\$ 6.61	\$ 10.12	\$ 2.38	\$ 0.94	\$ 7.50	\$ 9.81	\$ 29.52	\$ 5.64	\$ 0.85	\$ 1.18

CHK 2006 Fact 6

We were one of the most active consolidators in the industry, acquiring \$4.0 billion of oil and natural gas properties and \$14.3 billion since 1998

CHK 2006 Fact 7

We increased the company's inventories of U.S. onshore leasehold and 3-D seismic data to 10.7 million net acres and 16.3 million acres, respectively

Financial Review

(\$ In thousands, except per share data)

Years Ended December

Financial and Operating Data	2006	2005	2004	2003	2002
Revenues					
Oil and natural gas sales	\$ 5,618,894	\$ 3,272,585	\$ 1,936,176	\$ 1,296,822	\$ 568,187
Oil and natural gas marketing sales and service operations	1,706,701	1,392,705	773,092	420,610	170,315
Total revenues	\$ 7,325,595	\$ 4,665,290	\$ 2,709,268	\$ 1,717,432	\$ 738,502
Operating Costs					
Production expenses	489,499	316,956	204,821	137,583	98,191
Production taxes	176,440	207,898	103,931	77,893	30,101
General and administrative expenses	139,152	64,272	37,045	23,753	17,618
Oil and natural gas marketing and service operation expenses	1,589,770	1,358,003	755,314	410,288	165,736
Depreciation, depletion and amortization	1,462,759	945,001	611,322	386,258	235,198
Impairments and other	54,753	—	4,500	6,402	—
Total operating costs	3,912,373	2,892,130	1,716,933	1,042,177	546,844
Income (loss) from operations	3,413,222	1,773,160	992,335	675,255	191,658
Interest and other income	25,463	10,452	4,476	2,827	7,340
Interest expense	(300,722)	(219,800)	(167,328)	(154,356)	(112,031)
Miscellaneous gains (losses)	117,396	(70,419)	(24,557)	(22,774)	(19,827)
Total other income (expense)	(157,863)	(279,767)	(187,409)	(174,303)	(124,518)
Income (loss) before income taxes and cumulative effect of accounting change	3,255,359	1,493,393	804,926	500,952	67,140
Income tax expense (benefit):					
Current	5,000	—	—	5,000	(1,822)
Deferred	1,247,036	545,091	289,771	185,360	28,676
Net income (loss) before cumulative effect of accounting change, net of tax	2,003,323	948,302	515,155	310,592	40,286
Cumulative effect of accounting change, net of tax	—	—	—	2,389	—
Net income (loss)	\$ 2,003,323	\$ 948,302	\$ 515,155	\$ 312,981	\$ 40,286
Preferred stock dividends	(88,645)	(41,813)	(39,506)	(22,469)	(10,117)
Gain (loss) on redemption of preferred stock	(10,556)	(26,874)	(36,678)	—	—
Net income (loss) to common shareholders	\$ 1,904,122	\$ 879,615	\$ 438,971	\$ 290,512	\$ 30,169
Earnings per common share – basic:					
Income (loss) before cumulative effect of accounting change	\$ 4.78	\$ 2.73	\$ 1.73	\$ 1.36	\$ 0.18
Cumulative effect of accounting change	—	—	—	0.02	—
EPS – basic	\$ 4.78	\$ 2.73	\$ 1.73	\$ 1.38	\$ 0.18
Earnings per common share – assuming dilution:					
Income (loss) before cumulative effect of accounting change	\$ 4.35	\$ 2.51	\$ 1.53	\$ 1.20	\$ 0.17
Cumulative effect of accounting change	—	—	—	0.01	—
EPS – assuming dilution	\$ 4.35	\$ 2.51	\$ 1.53	\$ 1.21	\$ 0.17
Cash provided by (used in) operating activities (GAAP)	\$ 4,843,474	\$ 2,406,888	\$ 1,432,274	\$ 938,907	\$ 428,797
Operating cash flow (non-GAAP)*	\$ 4,045,109	\$ 2,425,727	\$ 1,402,522	\$ 897,234	\$ 408,783
Balance Sheet Data (at end of period):					
Total assets	\$ 24,417,167	\$ 16,118,462	\$ 8,244,509	\$ 4,572,291	\$ 2,875,608
Long-term debt, net of current maturities	7,375,548	5,489,742	3,075,109	2,057,713	1,651,198
Stockholders' equity (deficit)	\$ 11,251,471	\$ 6,124,323	\$ 3,162,883	\$ 1,732,810	\$ 907,875
Other Operating and Financial Data					
Proved reserves in natural gas equivalents (mmcf)	8,955,614	7,520,690	4,901,751	3,168,575	2,205,125
Future net oil and natural gas revenues discounted at 10%**	\$ 13,647,141	\$ 22,933,594	\$ 10,504,390	\$ 7,333,142	\$ 3,217,645
Natural gas price used in reserve report (per mcf)	\$ 5.41	\$ 8.76	\$ 5.65	\$ 5.68	\$ 4.28
Oil price used in reserve report (per bbl)	\$ 56.25	\$ 56.41	\$ 39.91	\$ 30.22	\$ 30.18
Natural gas production (mmcf)	526,459	422,389	322,009	240,366	160,682
Oil production (mmbbls)	8,654	7,698	6,764	4,665	3,466
Production (mmcf)	578,383	468,577	362,593	268,356	181,478
Sales price per mcf***	\$ 8.86	\$ 6.90	\$ 5.23	\$ 4.79	\$ 3.61
Production expense per mcf	\$ 0.85	\$ 0.68	\$ 0.56	\$ 0.51	\$ 0.54
Production taxes per mcf	\$ 0.31	\$ 0.44	\$ 0.29	\$ 0.29	\$ 0.17
General and administrative expense per mcf	\$ 0.24	\$ 0.14	\$ 0.10	\$ 0.09	\$ 0.10
Depreciation, depletion and amortization expense per mcf	\$ 2.53	\$ 2.02	\$ 1.69	\$ 1.44	\$ 1.30
Number of employees (full-time at end of period)	4,883	2,885	1,718	1,192	866
Cash dividends declared per common share	\$ 0.23	\$ 0.195	\$ 0.17	\$ 0.135	\$ 0.06
Stock price (at end of period – split adjusted)	\$ 29.05	\$ 31.73	\$ 16.50	\$ 13.58	\$ 7.74

* See page 15 for definition of this non-GAAP measure.

** PV-10 is the present value (10% discount rate) of estimated future gross revenue to be generated from the production of proved reserves, net of production and future development costs, using assumed prices and costs. Please see page 8 of our Form 10-K for information on the standardized measure of future net cash flow pursuant to SFAS 69.

*** Excludes unrealized gains (losses) on oil and natural gas hedging.

CHK 2006 Fact 4

We replaced 348% of our production with a drillbit finding and development cost of only \$1.93 per mcf

CHK 2006 Fact 5

We were the most active driller of new wells in the U.S., drilling 1,488 gross operated wells and participating in another 1,534 gross wells drilled by others

Dear Fellow Shareholders

Each year, my letter to shareholders has two objectives: first, to showcase the company's achievements during the preceding year and second, to highlight the issues we believe will be most important to us in the year ahead. This year there are four such issues: people, land, technology and climate change. The first three I have referred to in the past as the "building blocks of value creation" in the exploration and production (E&P) business. The fourth is of increasing importance to our industry, the U.S. and the world. Growing concern about climate change will create many opportunities for Chesapeake and our industry to promote the substantial environmental benefits of clean-burning natural gas, thereby enhancing the future value of the company's substantial natural gas reserves.

2006 In Review

Certainly 2006 was another in a series of extraordinary years for Chesapeake, as it was for energy producers and consumers around the globe. The year started with record high natural gas prices in the wake of Katrina and Rita's destructive path through the Gulf of Mexico. Only nine months later, the industry experienced four-year lows in natural gas prices primarily due to record warmth in the winter of 2005-06 and rebounding natural gas production volumes.

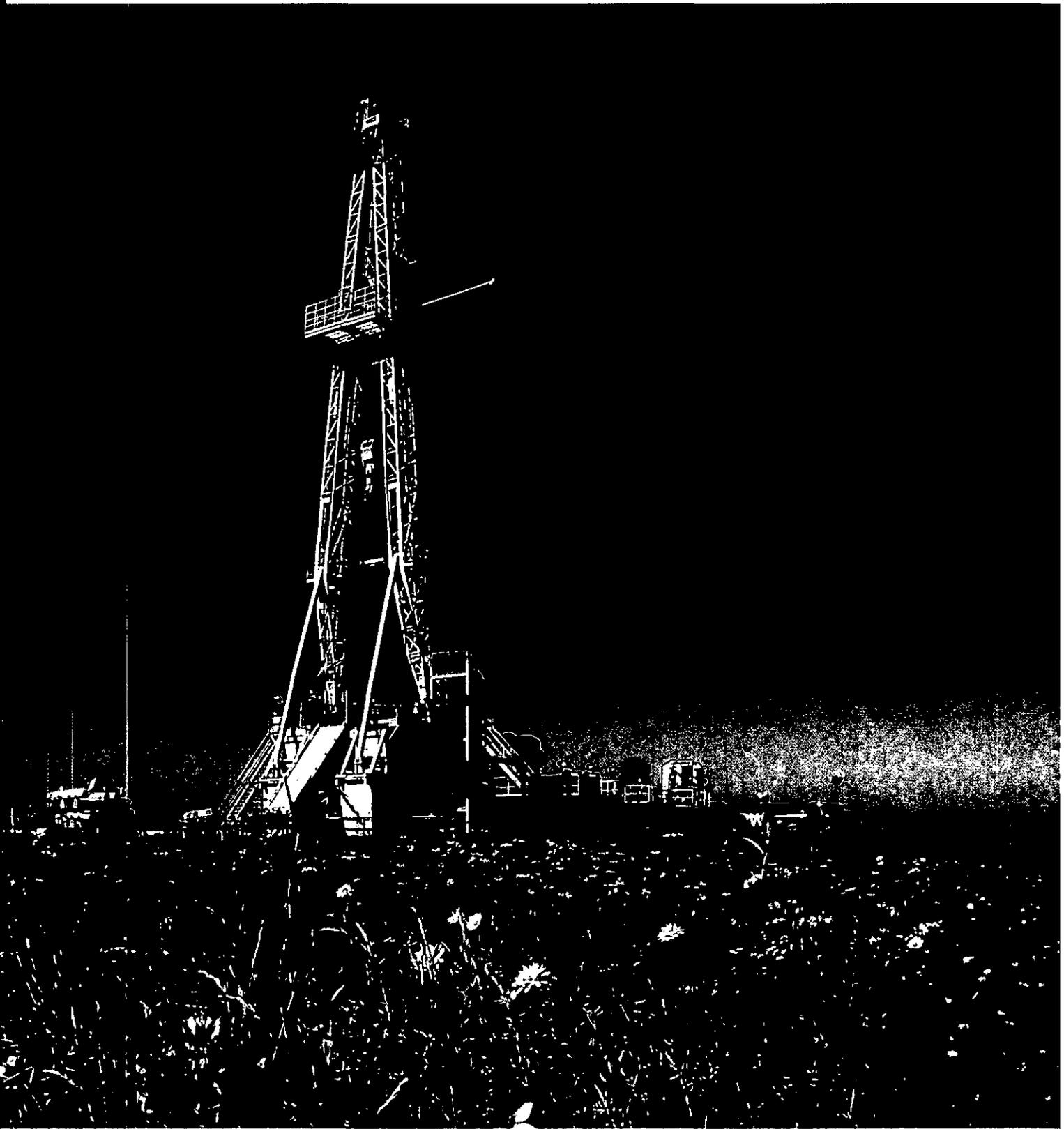
Despite long odds, this past winter started off with a repeat of the previous winter's record warmth, and natural gas prices ended 2006 near \$6 per mmbtu. However, a surprisingly strong cold spell from mid-January to mid-February 2007 eliminated the year-over-year natural gas storage surplus that had weighed heavily on natural gas prices for most of 2006. Natural gas prices have now settled into a more comfortable range around \$7.50.

Globally, last winter was the warmest in recorded history. Combined with political changes in Washington, D.C. last November, this record warmth has set the stage for a dramatically different environment in which to discuss global climate change. I will elaborate on the subject of climate change later in this letter.

Oil prices were also highly volatile in 2006, beginning the year just above \$60 per barrel, rising to \$77 during midsummer, and then falling back to \$60 by the end of the year (and as low as \$52 in early 2007). Although 91% of Chesapeake's production is natural gas, and oil and natural gas are not exact substitutes, oil still plays a very important role in how natural gas is priced. Natural gas prices have recently traded at a 20-40% discount to the price of oil on an energy equivalent (BTU) basis. Historically, the significant BTU discount of natural gas prices to oil prices has existed because natural gas is not as freely tradable around the world as oil and also natural gas is not influenced by geopolitical tensions in the same way oil is. Over time, however, we believe that natural gas prices will trade more closely to BTU parity with oil, given our view that natural gas demand will increase more quickly than oil demand in the years ahead.

Despite the volatility in oil and natural gas prices, Chesapeake delivered exceptional operating and financial results during 2006. Of particular note is management's proven ability to harness oil and natural gas price volatility to Chesapeake's advantage. Through our industry-leading hedging program, we generated \$1.3 billion in additional revenue in 2006 by capturing unusually high oil and natural gas prices when they were available. Simply put, we seek to be "price-makers" rather than "price-takers." This is in contrast to most of our competitors who seem satisfied to accept the prevailing every day or every month market price for the oil and natural gas they sell.

In our view, there are times when oil and natural gas prices rise to levels that are either likely to be unsustainable or are so attractive financially we believe we must take some chips off the table for our investors. In addition to enhancing our revenues through hedging, we also significantly lower the company's risk profile by reducing investors' exposure to the inherent volatility of energy prices. We believe our hedging skills are an increasingly valuable (but perhaps underappreciated) aspect of our management team's capabilities.



Leading-edge drilling techniques are being put to new uses as Chesapeake ramps up activities in the Fort Worth Barnett Shale of north-central Texas. In what may become the largest urban drilling program ever undertaken, Chesapeake's efforts in the Barnett Shale will utilize continually improving horizontal drilling and multiple well pad technologies enabling the company to drill more productive wells while reducing our environmental footprint.

Growing concern about climate change will create many opportunities for Chesapeake to promote the substantial environmental benefits of clean-burning natural gas, thereby enhancing the future value of the company's vast natural gas reserves.



Throughout the year, Chesapeake delivered consistently superior operational and financial results and steadily increased the company's net asset value per share. Unfortunately, our stock price decreased 8% during the year after having increased 92% in 2005. Against the backdrop of extreme volatility in natural gas markets that saw prices decline from near \$11 per mmbtu at the beginning of the year to a low of just above \$4 per mmbtu in the fall, the equity markets were unwilling to reward Chesapeake's strong operational and financial achievements in 2006.

Over time, however, the stock market has kept pace with the company's financial and operational performance (Chesapeake's stock price is up 2,100% in our 14 years as a public company) and we look forward to improved stock price performance in 2007 and the years ahead. We expect another terrific year of value creation this year through the continued execution of our simple and focused business strategy, the safe location of our assets onshore in the U.S. and the predictable base of production we generate

every day from approximately 35,000 producing wells. These attributes enable us to create substantial shareholder value from a business managed to mitigate risk and capture value from increasing volatility in oil and natural gas markets, which are significantly influenced by unpredictable weather patterns and turbulent geopolitical events.

A closer look at Chesapeake's achievements in 2006 reflects the following financial and operational highlights:

- | | |
|--|--|
| <ul style="list-style-type: none"> • Average daily oil and natural gas production increased 23% from 1.28 bcfe to 1.59 bcfe; • Proved oil and natural gas reserves increased 19% from 7.5 tcf to 9.0 tcf; • Reserve replacement for the year reached 348% at a drilling and acquisition cost of only \$1.93 per mcfe¹; | <ul style="list-style-type: none"> • Revenues rose 57% from \$4.7 billion to \$7.3 billion; • Ebitda² increased 89% from \$2.7 billion to \$5.0 billion; • Operating cash flow³ grew 67% from \$2.4 billion to \$4.0 billion; and • Net income per fully diluted common share increased 73% from \$2.51 to \$4.35. |
|--|--|

As a result of our achievements in 2006, Chesapeake became the third-largest independent producer of U.S. natural gas and the seventh-largest U.S. natural gas producer overall. Given our production growth trends and those of our competitors, we expect to end 2007 as a top-five producer of natural gas in the U.S. and possibly the largest independent natural gas producer. Moreover, we led the nation in drilling activity last year and we expect to do so again this year. In 2006, we utilized an average of 98 operated rigs and 79 non-operated rigs, or 11% of the nation's drilling rig fleet, to drill over 3,000 wells (1,450 net to Chesapeake). In 2007, we expect to use between 130-140 operated rigs and 80-90 non-operated rigs, thereby participating in approximately 13% of the nation's drilling activity. This drilling program should result in a production increase for 2007 of between 14-18%, an increase we expect will lead our large-cap peer group.

Chesapeake's proved and unproved oil and natural gas reserves continue to increase significantly as a result of our successful drilling and acquisition programs. Following an increase to 9 trillion cubic feet of natural gas equivalent (tcf) proved reserves (the energy equivalent of 1.5 billion barrels of oil) in 2006, Chesapeake's proved reserves should exceed 10 tcf by year-end 2007. Furthermore, we fully expect to reach at least 12 tcf (or 2 billion barrels of oil equivalent) by year-end 2009.

It is important to note the distinction between proved and unproved reserves has become increasingly blurred as the SEC definition of proved reserves (which was last updated in 1979) has not kept pace with the industry's ability to find, evaluate and produce natural gas reserves from unconventional reservoirs. While the industry has long known that fractured carbonates, tight sands and shales contain natural gas, it has only been the recent arrival of higher natural gas prices and greatly improved drilling and completion technologies that has made developing many of these reservoirs economical. However, because these reserves often lie in reservoirs that are continuous for tens of miles and the SEC definition of proved reserves only allows for the recognition of proved undeveloped reserves as direct offsets to producing wells in a particular formation, significant reserves of natural gas are not captured in the SEC's current definition of proved reserves. The substantial value of unproved reserves in unconventional reservoirs is evidenced by companies routinely valuing and paying for unproved reserves in today's acquisition market.

Our point is not to disagree with the SEC's reserve definitions, but rather to simply state our belief that today's E&P industry, and especially Chesapeake, is substantially undervalued in the equity markets because value is not always appropriately given by investors for what can be very significant amounts of low-risk unproved reserves.

At Chesapeake, we believe we have captured the nation's largest inventories of leasehold, 3-D seismic and unconventional natural gas resources. As a result, our 9 tcf of proved reserves are dwarfed by our 18 tcf of risked, unproved reserves and our 71 tcf of unrisked, unproved reserves. We believe Chesapeake's current stock price reflects very little of this large storehouse of future natural gas production. However, continued success from our industry-leading drilling campaign in 2007 should help highlight the enormity of Chesapeake's unproved reserves and should lead to more appropriate value recognition.

Chesapeake's Business Strategy and Natural Gas Focus

Chesapeake's business strategy is one of the easiest to understand among all E&P companies. We grow onshore in the U.S. through a balance of drilling and acquisitions, we regionally consolidate to achieve economies of scale, we focus almost exclusively on finding and producing natural gas and we work proactively to mitigate risk through hedging. By consistently and effectively executing this strategy, Chesapeake has become a member of the S&P 500 Index and the Fortune 500, was recognized in January 2007 by Forbes as "the best managed oil & gas company in the U.S.,"⁴ and has been one of America's top 15 best-performing stocks during the past eight years.⁵ In addition to the simplicity of our business strategy, our early recognition of evolving trends in the industry and our willingness to seize opportunities have distinguished Chesapeake among its peers and should provide us with competitive advantages for years to come.

Back in 1998 and early 1999, when natural gas was exceptionally cheap (frequently selling for less than \$1.25 per mmbtu), most industry and government observers predicted the U.S. natural gas market would increase from 22 trillion cubic feet (tcf) to 30 tcf per year by 2010 and natural gas prices would remain low indefinitely. After examining the fundamentals of the North American natural gas market, we arrived at a very different conclusion and began repositioning the company to pursue a contrarian strategy based on the following beliefs about the U.S. natural gas industry beyond the year 2000:

- | | |
|--|---|
| <ul style="list-style-type: none"> • depletion rates from producing wells would accelerate; • finding, development and operating costs would increase; • demand would gradually move away from more cost-sensitive industrial demand to less cost-sensitive electrical power generation demand; and | <ul style="list-style-type: none"> • production would soon reach a peak and begin a decline from which there would be no recovery, regardless of higher prices or improved technology. |
|--|---|

These trends became evident when we studied U.S. oil production history and then predicted U.S. natural gas production would likely follow a similar bell-shaped curve of ramping up to an historic peak (1970 for oil, 2001 for natural gas) and then slowly but steadily declining thereafter. We also reasoned that the major oil companies would begin withdrawing from the search for increasingly scarce natural gas reserves in North America and refocus their natural gas strategies on building global natural gas franchises around more abundant worldwide natural gas reserves that could be transformed into liquefied natural gas.

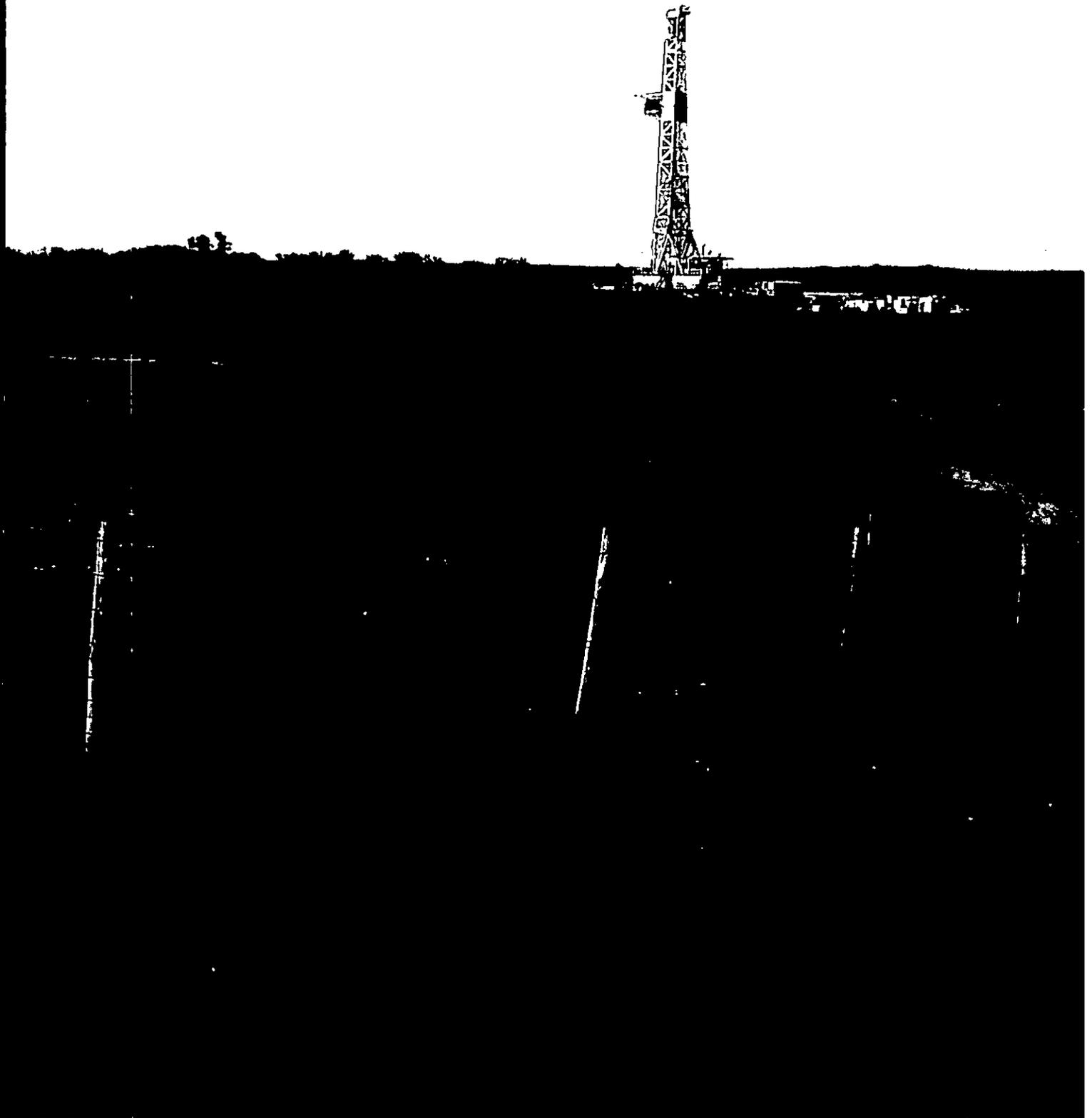
Accordingly, we decided Chesapeake should position itself to be a first mover to take advantage of multiple opportunities that we believed would emerge in the first decade of the 21st century. To that end, we adopted four objectives:

- | | |
|---|---|
| <ul style="list-style-type: none"> • acquire all of the existing natural gas production and reserves we could afford; • lease all the potentially productive natural gas acreage we could identify; | <ul style="list-style-type: none"> • hire all of the talented landmen, geoscientists and engineers we could find; and • focus exclusively onshore in the U.S., safely away from hurricanes and geopolitical unrest. |
|---|---|

Over the past nine years, we have accomplished these objectives. Meanwhile, with the help of higher oil prices, natural gas prices have risen to levels many times more than they were in 1998 and early 1999. More importantly, natural gas demand is likely to steadily increase as the U.S. economy grows and as natural gas is increasingly seen as the most practical way to reduce greenhouse gas emissions and reduce the risk of climate change. We believe this should lead to continuing natural gas price strength for years to come. As a result of anticipating these trends and getting ahead of our competition, Chesapeake remains very well positioned for future success.

People, Land and Technology

Chesapeake's industry-leading drilling activity and consistent annual production growth require great people, abundant leasehold and the latest technologies – attributes that Chesapeake fortunately has in abundance. Our employees now number approximately 5,000, our leasehold inventory of 11 million net acres provides 26,000 future net drilling opportunities and our technological superiority in 3-D seismic interpretation, unconventional reservoir analysis and deep vertical and horizontal drilling capabilities provides many competitive advantages.



Chesapeake's inventory of leasehold has now reached 11 million net acres, on which we believe 26,000 additional net wells can be drilled. This represents more than a 10-year backlog of drilling opportunities and a vast storehouse of unrecognized value in our company.

People

First and foremost, Chesapeake is a people company – our employees work creatively and enthusiastically for our shareholders to profitably produce an environmentally superior product millions of Americans rely on every day. In 2000, Chesapeake was one of the first companies to recognize that after 15 years of downsizing, the E&P industry was not prepared to meet the rising demand for natural gas. The average age of a petroleum geoscientist, landman or engineer in the U.S. is now more than 50 years and after a five-year increase in energy prices, the country is still graduating fewer than 3,500 petroleum geoscientists and engineers per year (compared to almost 44,000 new lawyers each year). Retirements are estimated to be running at almost the same level as new graduates are entering the industry, and these retirements will accelerate in the next 15 years as today's average-aged geoscientist, landman and engineer reaches traditional retirement age.

Because of Chesapeake's early recognition of this looming shortage of industry talent, we began aggressively hiring young technical talent. We now employ more than 200 degreed geoscientists, landmen and engineers under the age of 35, and the average age of our geoscience, land and engineering departments has dropped from 49 in 2000 to 40 today. Talent creates value and our company has an abundance of talented people creating value every day. Chesapeake now employs nearly 1,100 employees in its geoscience, land and engineering departments, of which 70% are degreed professionals.

In total, the company has approximately 5,000 employees, of whom approximately 60% work in our E&P operations and 40% work in our oilfield service operations. Chesapeake's people are a highly valued (and much coveted) resource and we are proud they have chosen our company as their professional home. Continuing a tradition we started in 1994, a complete list of our employees sorted by the year they joined the company begins on page 28 of this report.

Land

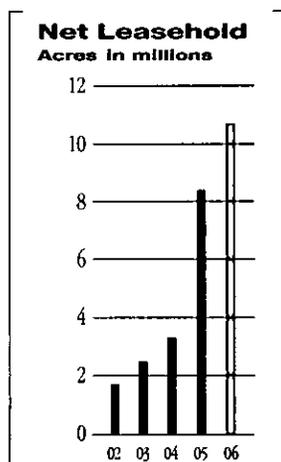
Now I would like to turn to my favorite of the three building blocks of value creation – land (in full disclosure of my bias on this point, I am a history major by education but a petroleum landman by vocational training). Land is the foundation of all value creation in the E&P business. Geoscientists and engineers can have great ideas, but without a lease those great ideas have no value

– as we say in the business, “Without the lease, there is no grease.” Chesapeake is one of the few E&P companies to have a landman as its CEO, and perhaps as a consequence, we have been more willing than our competitors to acquire an unusually large inventory of leasehold on which to drill wells. Our inventory of 11 million net acres of leasehold and 26,000 net drilling locations represents more than a 10-year drilling backlog and a vast storehouse of unrecognized value in our company.

We embarked on this aggressive “land grab” in 2000 as we recognized earlier than most of our competitors that vast new areas of the U.S. would open up for natural gas exploration and development when new horizontal drilling and completion technologies were applied to different types of rocks (now commonly referred to as “unconventional reservoirs”) in a time of structurally higher natural gas prices. We believed this decade would go down in oil and natural gas history as a once-in-a-generation opportunity to acquire leases in the modern day equivalent of the great Oklahoma land rushes of the late 19th century.

Today that land grab is largely over, and not surprisingly, we believe Chesapeake won. The leasehold we now own could not be reassembled in today's ultra-competitive marketplace – and what we have built is unique,

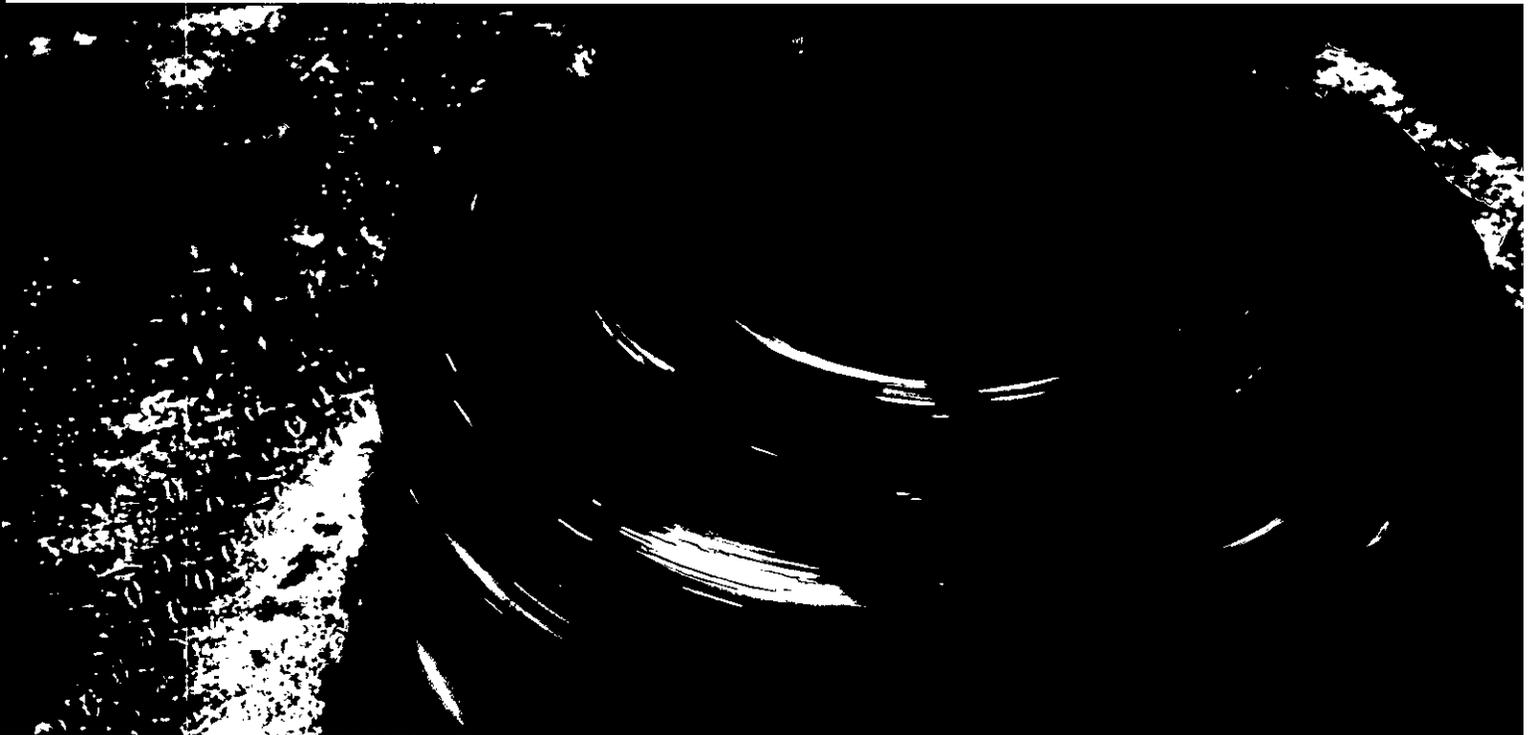
large and exceptionally valuable. Our investment to date in this undeveloped leasehold exceeds \$6 billion, but we believe its value over time will prove to be a significant multiple of that. Having acquired this enormous inventory of opportunities, we have also been building the employee, infrastructure and support systems to enable Chesapeake to execute a drilling program with a size and technological sophistication that is unprecedented in the E&P industry. The results of this drilling program over the next few years are likely to make Chesapeake the largest producer of natural gas in the U.S. and should create billions of dollars of value for our shareholders.



To help investors more easily analyze Chesapeake's extensive drilling inventory, we divide it into four play types: conventional gas resource, unconventional gas resource, emerging gas resource and Appalachian Basin gas resource. The company's current leasehold and proved reserve, risked, unproved reserve and unrisked, unproved reserve totals by play type are set forth below:

- 3.2 million net acres in our traditional conventional plays (i.e., much of the Mid-Continent, Permian, Gulf Coast, South Texas and other areas) on which we have identified approximately 3,500 drillsites, 3.9 tcf of proved reserves, approximately 3.1 tcf of risked, unproved reserves and approximately 20 tcf of unrisked, unproved reserves;
- 1.3 million net acres in our unconventional gas resource plays (i.e., Fort Worth Barnett Shale, Sahara, Granite/Atoka/Colony Washes, and Ark-La-Tex tight sands) on which we have identified approximately 9,800 drillsites, 3.4 tcf of proved reserves, approximately 6.6 tcf of risked, unproved reserves and approximately 11 tcf of unrisked, unproved reserves;
- 2.7 million net acres in our emerging gas resource plays (i.e., Fayetteville Shale, Delaware Barnett and Woodford Shales, Deep Haley, Deep Bossier and others) on which we have identified approximately 3,300 drillsites, 0.2 tcf of proved reserves, approximately 5.6 tcf of risked, unproved reserves and approximately 36 tcf of unrisked, unproved reserves; and
- 3.5 million net acres in the Appalachian Basin, where our play types range from conventional to unconventional to emerging gas resource. On the significant Appalachian Basin acreage base primarily acquired in our November 2005 acquisition of Columbia Natural Resources, we have identified approximately 9,000 drillsites, 1.5 tcf of proved reserves, approximately 2.4 tcf of risked, unproved reserves and approximately 4 tcf of unrisked, unproved reserves.

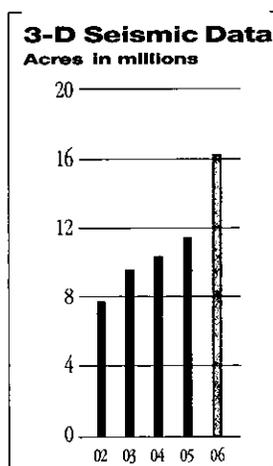
The company continues to actively acquire more acreage throughout our operating areas. In 2006, we acquired 1.9 million net acres through an aggressive land acquisition program currently utilizing almost 2,000 contract landmen in the field. This is an unsurpassed commitment to ensure Chesapeake will always have a substantial backlog of value-creating projects for its investors.



Technology

In another example of early recognition of evolving industry trends, Chesapeake's management team in the late 1990s correctly anticipated that better technologies applied to unconventional reservoirs in a time of structurally higher natural gas prices would result in the discovery and development of many tcf of new natural gas reserves.

As I think back on Chesapeake's founding in 1989, this is exactly what we started our company to accomplish – utilize the new technology of drilling horizontal wells in unconventional reservoirs to avoid the risk of drilling a dry hole. We began by developing southern Oklahoma fractured carbonate rocks such as the Sycamore, Woodford, Hunton and Viola formations, and later expanded into various Austin Chalk plays of south-central and southeastern Texas. We did not know enough at the time to brand these fractured carbonates as “unconventional,” but they certainly were. For a long time our company's reputation paid a price for focusing on these fractured carbonates, reservoirs that for decades the industry knew contained oil and natural gas, but were not economical to develop. Ironically, what was contrarian and controversial 18 years ago has today become a widely followed strategy in our industry.



While we were very successful in cracking the code to these unconventional reservoirs in Oklahoma and Texas in the late 1980s and early 1990s, we were less successful in the mid-1990s extending our early success in the Austin Chalk to Louisiana. That painful failure in Louisiana and the collapse of oil and natural gas prices in 1998-99 led to Chesapeake's retreat, for a time, from unconventional plays. However, when it became clear after 2000 that unconventional formations might yield vast reserves of previously uneconomical natural gas to horizontally drilled wells with fracture stimulations isolated in discrete intervals (a technology not previously perfected), Chesapeake returned to its roots and began to aggressively pursue new unconventional gas resource plays with substantial upside.

The most notable of these unconventional plays is the Fort Worth Barnett Shale. Centered around Fort Worth, Texas, the Fort Worth Barnett Shale has emerged as one of America's largest natural gas fields and is the best example of what can happen at today's three-way intersection of improved horizontal drilling and completion technology, a better scientific understanding of how shales work and structurally higher natural gas prices.

This play is currently responsible for approximately 4% of U.S. natural gas production and almost 10% of the nation's drilling activity. Its importance to the U.S. will greatly increase in the years ahead as Chesapeake and others drill thousands of wells to develop this exceptionally large natural gas resource base estimated to contain at least 25 tcf.

Chesapeake entered the Fort Worth Barnett Shale in 2002 through an acquisition that included 4,000 net acres in the play (for which, at the time of the acquisition, we gave no value). Since that time, we have assembled almost 200,000 net acres of leasehold in what is referred to as the Tier 1 area of the play, principally in Johnson, Tarrant and western Dallas counties. In the Tier 1 area, Chesapeake now owns the industry's largest leasehold position and has drilled or acquired nearly 400 wells that are today producing about 285 million cubic feet of natural gas equivalent (mmcf) (190 mmcf net to Chesapeake). We are currently the fourth-largest producer of natural gas in the Barnett play, but with our current drilling activity of 25 rigs moving to a projected industry-leading 35 rigs by midyear 2007, we anticipate becoming the second-largest producer of natural gas from the Fort Worth Barnett Shale by year-end 2007.

This year Chesapeake expects to invest approximately \$1 billion in the Fort Worth Barnett Shale to drill nearly 400 gross wells. While this represents just 25% of our drilling capital expenditures for the year, we anticipate this drilling program will be prolific enough to replace nearly all of Chesapeake's production during 2007, allowing our remaining capital expenditures to generate significant overall growth. Furthermore, this play will remain the foundation of our growth for years to come as we currently have enough leasehold to drill 2,300 additional net wells, representing almost 4 tcf of future reserves. In recognition of the play's attractiveness, we continue to acquire more leasehold in the play, especially in and around metropolitan Fort Worth, where we believe the most favorable geology exists and where the best wells will likely be drilled.



In the foreground, 3-D seismic trucks are in action at the DFW International Airport between Dallas and Fort Worth. In 2006, Chesapeake was selected as the airport's exclusive partner to develop the potentially vast reserves of Barnett Shale natural gas underlying the airport's 18,000 net acres. Chesapeake's 3-D seismic work is the precursor to drilling activities that will begin in May 2007.

Climate Change

Probably no public policy debate has evolved so dramatically in the past year as the debate about global climate change. A year ago, it would have been difficult to anticipate the broad consensus that has emerged among the world's scientists and policymakers about the need to begin taking action to reduce the threat of global climate change. As a company employing dozens of earth scientists (and two meteorologists), we are fully aware there have been many times in the past when the earth's temperatures were much higher than they are today, but with lower CO₂ levels, and also many times when CO₂ levels were much higher than they are today, but with lower global temperatures. So to us, climate change over a long period of time is a normal and inevitable process caused by an ever-changing planet.

However, even as we continue to learn more about the earth's long history of climate change, it is difficult to ignore that humans directly and indirectly consume energy, create heat and release carbon – a simple fact of everyday life. The debate is centered around whether these human activities are the cause of the steady rise of greenhouse gas concentrations and worldwide temperatures during the past 20 years. Our view is that it is largely irrelevant whether or not the increases in greenhouse gas emissions and global temperatures are natural or influenced by humans. The fact is we can, and should, reduce our greenhouse gas emissions because the risks associated with failing to do so are simply too great.

This is where Chesapeake and natural gas can come to the rescue. As the debate in America intensifies about how to become more energy independent in an increasingly dangerous world and at the same time reduce greenhouse gas emissions in a growing economy, we need to frame the problem truthfully and solve it practically. The vast majority of greenhouse gas emissions are caused by transportation vehicles burning gasoline and diesel and by power plants and factories burning coal. Today, we see policymakers promoting alternative fuels such as wind, solar, biofuels and nuclear. These are all legitimate alternatives (although some much less so than others), yet none can offer energy in great abundance at a reasonable price anytime soon. On the other hand, burning natural gas instead of gasoline, diesel or coal reduces greenhouse gas emissions by approximately 50%. We believe the evidence clearly demonstrates that natural gas is by far the most practical solution to the problem – it is abundant, affordable, reliable, clean burning and domestically produced.

To spread the word about the positive attributes of natural gas, Chesapeake has recently helped establish a foundation based in Washington, D.C., called the American Clean Skies Foundation (www.americancleanskies.com). This foundation will become a

leading voice in the debate about how to reduce greenhouse gas emissions and avoid abrupt climate change. The foundation will encourage conservation of all types of energy, but will primarily advocate the increased use of natural gas in the U.S. and around the world.

For many years, natural gas has been valued at a BTU discount to oil. We believe the opportunity is now at hand for the climate change debate to lead to an increased appreciation of natural gas and a higher valuation for the superior fuel we produce. We intend to do well for our shareholders by doing well for our country and our world. We hope you will join us by visiting the foundation's web site and adding your contribution to ours to make the world a better place.

Looking Forward

As I conclude this letter and reflect on 2006's accomplishments and also consider the opportunities ahead, I am grateful for 14 years of investor support of Chesapeake. Following exceedingly humble beginnings and an adolescent growth spurt accompanied by many challenges, Chesapeake has now emerged as a true industry leader characterized by value creation, constant innovation, risk mitigation, forward thinking and hard work.

We have the commitment and talents of 5,000 top-notch employees, an engaged and insightful Board of Directors, a time-tested and successful business strategy, a value-added risk management program, a steadily improving balance sheet and a large and increasingly valuable onshore U.S. natural gas asset base. Furthermore, Chesapeake offers an entrepreneurial and experienced management team that has proven itself capable of creating value through a full range of commodity cycles and challenges in building a \$24 billion enterprise value company from an initial \$50,000 investment in just 18 years.

We are off to a great start in delivering another successful year of financial and operational performance to our shareholders in 2007. Chesapeake's production and proved reserves should once again reach new records with double-digit growth and we expect to generate another year of substantial gains from our hedging program. Though volatility will remain, natural gas prices should stay strong during the year as tighter supply and demand fundamentals in both U.S. natural gas and world oil markets emerge this summer and beyond.

Finally, Chesapeake is on the right side of history in the climate change debate and we expect natural gas to become more highly valued in the years ahead as a result of its substantial environmental benefits. Just as coal was the fuel of the 18th and 19th centuries and oil was the fuel of the 20th century, natural gas will be the fuel of at least the first quarter of the 21st century and perhaps for far longer. As a result, we believe the stage is set for an extended period of strong natural gas prices and we look forward to Chesapeake continuing to deliver exceptional results to our shareholders in 2007 and beyond.

Best regards,



Aubrey K. McClendon
Chairman and Chief Executive Officer
March 31, 2007

¹ Reserve replacement is calculated by dividing the sum of reserve additions from all sources by actual production for the corresponding period. We calculate drilling and acquisition cost per mcfe by dividing total costs incurred during the year, less certain costs primarily related to unproved property acquisitions, geological and geophysical cost and deferred taxes related to corporate acquisitions by total proved reserve additions excluding price-related revisions.

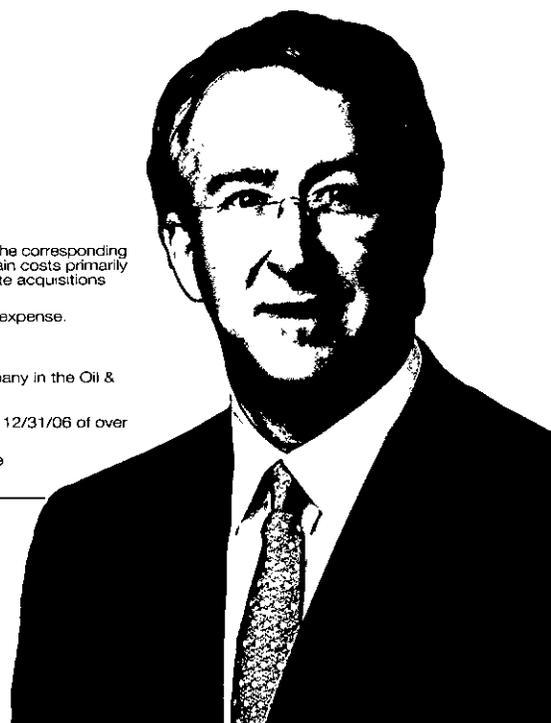
² Ebitda is net income before interest expense, income tax expense, and depreciation, depletion and amortization expense.

³ Operating cash flow is net cash provided by operating activities before changes in assets and liabilities.

⁴ Listing in Forbes' Platinum 400 list of America's Best Big Companies and recognized as the best managed company in the Oil & Gas Operations category in the magazine's 1/8/07 issue.

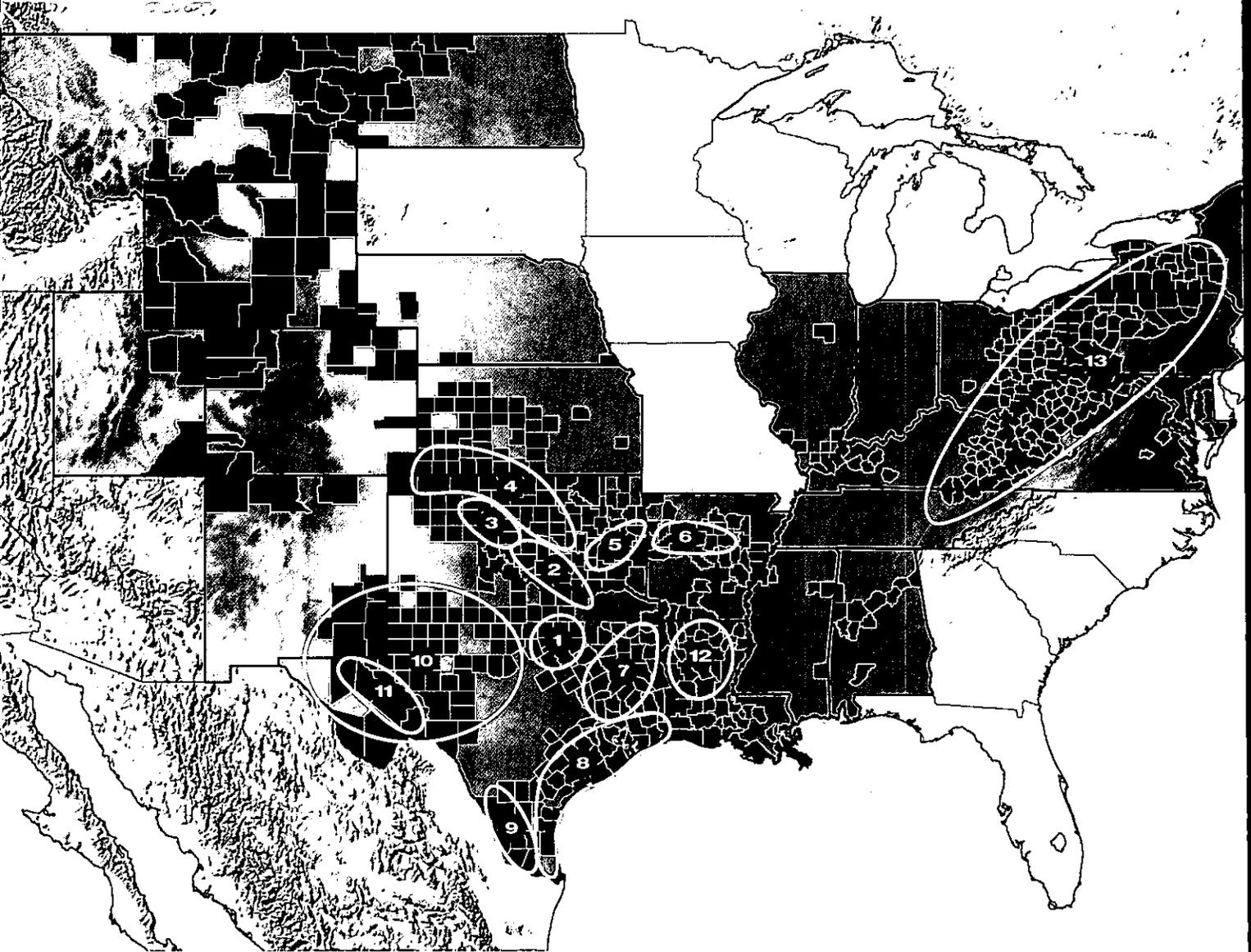
⁵ Ranking is according to Zack's Investment Research (Zack's) based on stock price performance from 12/31/98 to 12/31/06 of over 3,200 companies tracked by Zack's with market capitalizations over \$50 million on 12/31/98.

Note: Reconciliations and other information on the measures referenced in notes 1, 2 and 3 are presented on the Reconciliation of Non-GAAP Financial Measures page on our web site at www.chkenergy.com.



Aubrey K. McClendon
Co-Founder, Chairman
and Chief Executive Officer

CHK's Operating Area Map



Chesapeake embarked on an aggressive “land grab” in 2000 as we recognized earlier than most of our competitors that vast new areas of the U.S. would open up for natural gas exploration and development when new horizontal drilling and completion technologies were applied to different types of rocks (now commonly referred to as “unconventional reservoirs”) in a time of structurally higher natural gas prices. We believed this decade would go down in oil and natural gas history as a once-in-a-generation opportunity to acquire leases in the modern day equivalent of the great Oklahoma land rushes of the late 19th century. Today that land grab is largely over and we believe Chesapeake won by acquiring a leasehold inventory of 11 million net acres, on which we expect to drill 26,000 net wells in the years to come.

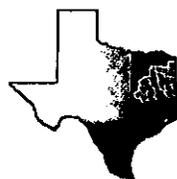
■ Counties with CHK Leasehold

CHK: The Biggest Gas Resource Player in the U.S.



One of Chesapeake's most important natural gas resource plays is the Sahara area of northwest Oklahoma. To date, we have drilled more than 1,000 wells in the Sahara and we anticipate drilling another 6,000 in the years ahead.

- 7 East Texas** In East Texas, Chesapeake is focused on developing various tight natural gas sand formations in medium to deep horizons, including the Pettet, Travis Peak, and Cotton Valley formations. In addition, we are one of the top three leasehold owners in the emerging Deep Bossier play that has recently yielded impressive exploration results. We are currently drilling our first operated Deep Bossier well, a 22,000-foot well in Madison County.



2006 Total Production:
16 bcfe, +78%, 3%

12/31/06 Proved Reserves:
386 bcfe, +9%, 4%

12/31/06 Net Leasehold Acres:
494,000, +577%, 5%

- 8 Texas Gulf Coast** Chesapeake has established a significant presence in a number of counties along the prolific Texas Gulf Coast. Throughout this area we utilize 3-D seismic data to delineate structural and stratigraphic traps, primarily in the Frio, Yegua and Wilcox formations. During the past few years, Chesapeake has obtained 2,000 square miles of 3-D seismic data and has drilled a number of significant wells as a result.



2006 Total Production:
27 bcfe, +13%, 5%

12/31/06 Proved Reserves:
107 bcfe, -17%, 1%

12/31/06 Net Leasehold Acres:
256,000, +13%, 2%

- 9 South Texas** The South Texas area remained one of the largest areas of natural gas production for Chesapeake in 2006. In South Texas, our operations are primarily focused in Zapata County, which is Texas' number one natural gas producing county and where Chesapeake is the third-largest natural gas producer. During 2007, we will focus on developing deeper structural opportunities under the traditional Lobo and Perdido objectives.

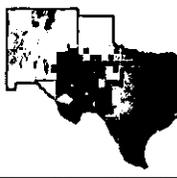


2006 Total Production:
52 bcfe, +30%, 9%

12/31/06 Proved Reserves:
554 bcfe, +12%, 6%

12/31/06 Net Leasehold Acres:
156,000, +2%, 1%

- 10 Permian Basin** In the northern portion of the Permian Basin, Chesapeake has focused on discovering and developing various shallow- to medium-depth oil and natural gas plays and also operates a number of secondary recovery oil projects. In the southern portion of the Permian, we have focused on developing new shallow- to medium-depth natural gas plays in the Val Verde Basin where we have recently made a potentially significant new discovery.



2006 Total Production:
33 bcfe, +6%, 6%

12/31/06 Proved Reserves:
482 bcfe, -10%, 5%

12/31/06 Net Leasehold Acres:
858,000, +61%, 8%

- 11 Delaware Basin** Chesapeake's most significant land acquisition activities during 2006 took place in the Delaware Basin in far West Texas where we have built the largest leasehold position in the emerging Barnett and Woodford Shale plays. We believe that substantial natural gas reserves exist in this stacked shale play and are working to determine its commerciality. The Delaware Basin also includes the Deep Haley play, which is centered in Loving County, Texas. In Haley, Chesapeake owns the industry's second-largest leasehold where we are targeting the prolific and over-pressured Strawn, Atoka and Morrow formations that are located at depths of 15,000-18,000 feet. Our production from Haley has recently doubled as a result of several prolific new wells.



2006 Total Production:
16 bcfe, +23%, 3%

12/31/06 Proved Reserves:
243 bcfe, +22%, 3%

12/31/06 Net Leasehold Acres:
667,000, +409%, 6%

- 12 Louisiana** In Louisiana, Chesapeake is primarily focused on the northern portion of the state where we are actively developing such prolific formations as the Hosston, Cotton Valley and Deep Bossier, all of which are tight sand plays and offer significant upside potential. We also have several new 3-D seismic surveys planned for Louisiana and are pursuing unconventional objectives there as well.

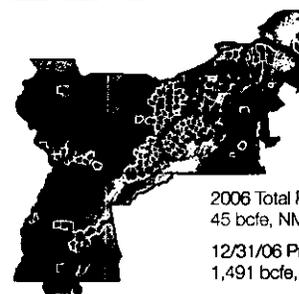


2006 Total Production:
30 bcfe, -5%, 5%

12/31/06 Proved Reserves:
326 bcfe, -18%, 4%

12/31/06 Net Leasehold Acres:
235,000, +1%, 2%

- 13 Appalachia** During 2006, Chesapeake successfully integrated the November 2005 \$3 billion acquisition of Columbia Natural Resources and began laying the groundwork for future growth and value creation from the area. Our 2006 reserve and production growth from Appalachia benefited from an accelerated drilling program and exceeded our expectations. Often referred to as America's most drilled, but least explored area, Appalachia presents abundant growth opportunities through the application of leading-edge exploration, drilling and production technologies in which Chesapeake is a recognized industry leader. We are currently assessing the potential of deeper drilling opportunities and will be aided by a substantial amount of new proprietary 3-D seismic data. In addition, we are pursuing a variety of new initiatives to develop unconventional shales in Alabama, southern Illinois and western Kentucky and will drill our first operated horizontal shale well in Appalachia in mid-2007.



2006 Total Production:
45 bcfe, NM**, 8%

12/31/06 Proved Reserves:
1,491 bcfe, +15%, 17%

12/31/06 Net Leasehold Acres:
3,837,000, +21%, 36%

Social Responsibility and Community Service

The first responsibility of every publicly held company is to build value for its shareholders while providing a product or service vital to economic and social development. A second important responsibility should be to serve as a conscientious corporate citizen in every community where it conducts business. Since our founding in 1989, Chesapeake has been committed to meeting both responsibilities: building shareholder value while helping make the world a better place.

Educational Commitment

In a knowledge-driven global economy, Chesapeake focuses on a U.S.-based business model that builds both the competitive skills of its work force and the communities where its employees live, work and play. We accomplish this important goal through work-force training and investments in education at all levels.

In 2003, we began a relatively small program to provide college scholarships to students from rural Oklahoma communities. Since its inception, the Chesapeake Scholars program has grown into one of the larger corporate scholarship programs in America, pledging over \$6 million dollars to well-deserving students. Twenty-two colleges and universities around the nation currently receive financial support from this program, a number expected to grow to 35 programs in 2007.

While today's Chesapeake Scholars will continue to receive general support in their chosen fields of endeavor, future scholarship recipients will be more focused in areas such as the geosciences, petroleum engineering, land, information technology, human resources, accounting and law. The energy industry is growing quickly, and skilled, well-educated employees are highly sought after as valuable contributors to the success of Chesapeake and our industry.

Among the many bright spots in our educational support program is Chesapeake's partnership with Southern West Virginia Community College (SWVCC) at its main campus in Logan County, West Virginia. For 30 years, SWVCC has made higher education more accessible to both traditional and nontraditional students in southern West Virginia, the core of Chesapeake's Appalachian natural gas producing base. In addition, understanding that natural gas exploration and production is an increasingly vital part of West Virginia's future, Chesapeake's financial support of the soon-to-open Academy for Mine Safety and Energy Technologies at SWVCC will provide education and training for future leaders of both the mining and natural gas industries.

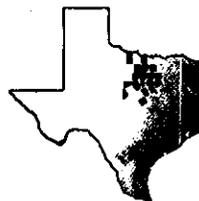
Another example of Chesapeake's educational commitment is our recent \$500,000 donation to the Oklahoma School of Science and Mathematics in Oklahoma City to create the first endowed chair in a public high school in the state's history. The professor filling the Chesapeake Chair for Geoscience will be teaching some of the state's brightest high school junior and senior students about the exciting world of geology and geophysics. By planting seeds at this early stage, we anticipate some of these gifted students will continue an academic path in the geosciences, ultimately leading them to highly rewarding technology-driven careers critical to today's increasingly challenging search for clean-burning natural gas reserves.

The company's educational initiatives extend to the grade school level as well. For example, Nash Elementary School in Fort Worth, Texas, the capital of the prolific gas-producing Barnett Shale, received a donation from Chesapeake that enabled every teacher to have his or her own laptop computer in class. This allows both teachers and students to benefit from easier access to the latest information and technologies.

Just as Nash Elementary in Fort Worth has benefited from Chesapeake's corporate philanthropy, so has Horace Mann Elementary School, our adopted grade school located just blocks from our corporate headquarters in Oklahoma City. In addition to significant yearly financial support, more than 100 dedicated Chesapeake employee mentors spend an hour of company time every week reading and talking to their students. By investing in the physical appearance of the school and by providing an effective mentoring

CHK's Operating Area Summaries

- 1 Fort Worth Barnett Shale** The Fort Worth Barnett Shale was Chesapeake's greatest area of investment during 2006 and will be the most important contributor to our growth in 2007. In addition to multiple acquisitions of high-quality assets during 2006, Chesapeake also notably leased the right to drill the 18,000 net acres underlying the Dallas/Fort Worth International Airport. In the Barnett, Chesapeake is the fourth-largest producer of natural gas, the most active driller and the largest leasehold owner in the Tier 1 sweet spot of Tarrant, Johnson and western Dallas counties. We are rapidly increasing our drilling activity in the play and expect to be completing, on average, one new Barnett Shale well every day by midyear 2007.



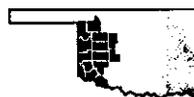
2006 Total Production:
44 bcfe, +152%*, 8%**
12/31/06 Proved Reserves:
1,141 bcfe, +258%*, 13%**
12/31/06 Net Leasehold Acres:
182,000, +231%*, 2%**

- 2 Southern Oklahoma** Chesapeake's Southern Oklahoma area encompasses some of Oklahoma's oldest and largest fields, several of which date back to discoveries in the early 1900s. This area is also home to Chesapeake's earliest drilling successes in the Golden Trend and Sholem Alechem fields. Today our activities focus on the Bray, Southwest Duncan, Colt and Cement areas where we are developing both conventional and unconventional objectives.



2006 Total Production:
55 bcfe, 0%, 10%
12/31/06 Proved Reserves:
775 bcfe, +3%, 9%
12/31/06 Net Leasehold Acres:
388,000, -3%, 4%

- 3 Anadarko Basin** The Anadarko Basin, which remains Chesapeake's largest area of natural gas production, is characterized by a wide variety of play types and depth ranges, including some of the most complex and prolific natural gas reservoirs in the U.S. In this area, Chesapeake remains the most active driller and largest producer and focuses on three major play types found between 12,000 and 20,000 feet: deep Morrow-Springer; medium-depth Red Fork-Morrow-Springer; and vertically and horizontally drilled medium-depth Granite, Atoka and Colony Washes.



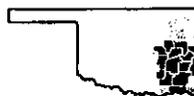
2006 Total Production:
102 bcfe, -4%, 18%
12/31/06 Proved Reserves:
1,043 bcfe, +2%, 12%
12/31/06 Net Leasehold Acres:
607,000, 0%, 6%

- 4 Northern Mid-Continent** The Northern Mid-Continent area was a key contributor to our growth in 2006 and includes northwest Oklahoma, the Texas and Oklahoma panhandles and southwest Kansas. In addition to various conventional plays in this area, we focus on the massive Sahara unconventional natural gas resource project. In Sahara, Chesapeake is by far the dominant operator with more than 600,000 net acres under lease in this multi-county area of excellent low-risk, shallow natural gas production. Since 1998, we have drilled over 1,000 wells in Sahara and have plans to drill an additional 6,000 net wells in the next 10 years.



2006 Total Production:
117 bcfe, +15%, 20%
12/31/06 Proved Reserves:
1,922 bcfe, +17%, 21%
12/31/06 Net Leasehold Acres:
1,507,000, +15%, 14%

- 5 Oklahoma Arkoma** The Oklahoma portion of the Arkoma Basin has long been an extremely prolific natural gas region. In this area, Chesapeake is targeting a variety of plays ranging from complex overthrust geological targets in the southern portion of the basin, to shallow horizontally drilled coalbed methane (CBM) wells in the northern portion of the basin, to the emerging unconventional Woodford Shale play in the western portion of the basin. In the CBM and Woodford plays, we have now established the second-largest leasehold positions.



2006 Total Production:
37 Bcfe, +19%, 6%
12/31/06 Proved Reserves:
394 Bcfe, +10%, 4%
12/31/06 Net Leasehold Acres:
458,000, 0%, 4%

- 6 Fayetteville Shale** Chesapeake owns the industry's largest acreage position in the high-potential Arkansas Fayetteville Shale play, including the second-largest acreage position in the play's core area. During 2006, we focused on testing the boundaries of our acreage position, obtaining 3-D seismic surveys and optimizing drilling and completion techniques. We are now in the process of increasing our drilling activity from three to 12 rigs to accelerate reserve and production growth from this promising play.



2006 Total Production:
4 bcfe, +33%, 1%
12/31/06 Proved Reserves:
92 bcfe, +142%, 1%
12/31/06 Net Leasehold Acres:
1,101,000, +95%, 10%

* compared to last year
** % of company total
*** not meaningful

program, Chesapeake has helped Horace Mann's students achieve significant improvements in test scores. Neighborhood property values have risen approximately 20% as the school becomes an ever more attractive place for children to attend.

Quality of Life Commitment

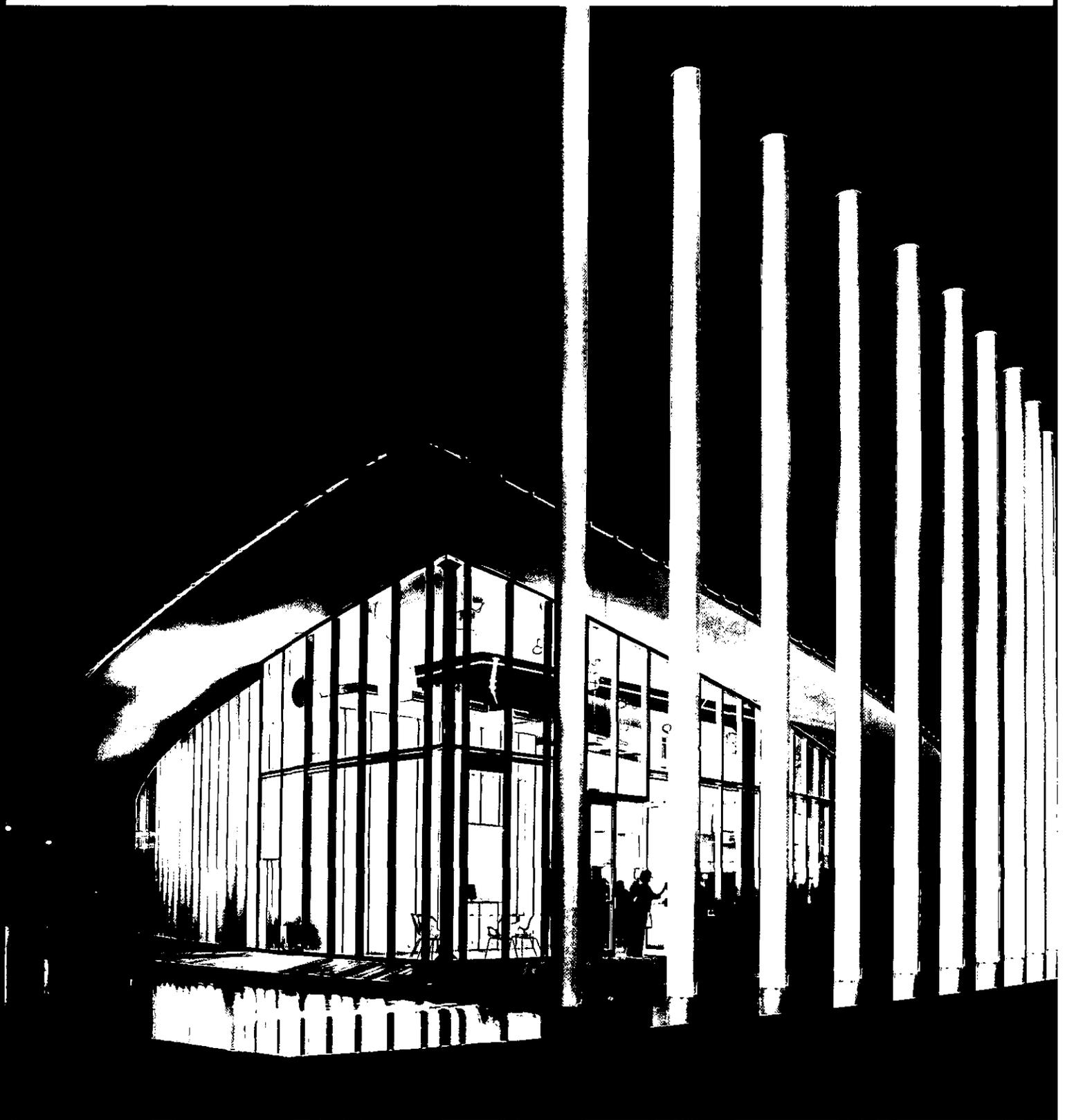
In addition to educational advancement, Chesapeake is committed to improving the quality of life and encouraging economic development in the communities where we operate. An exciting example is the story of Chesapeake's contribution to the Oklahoma City Boathouse Foundation and how it is transforming the riverfront area in the city's downtown into a vibrant destination for rowers and tourists across the state and country. The Chesapeake Boathouse, an acclaimed modern architectural icon, has already hosted a major rowing event with over 30,000 spectators and 1,000 athletes, including the U.S. National, Harvard University and U.S. Naval Academy rowing teams. In October 2007, the Chesapeake Boathouse will host its first international event, the USA Rowing World Challenge. This event will feature teams from around the world as they prepare for the 2008 Olympic Games in Beijing. Oklahoma City is rapidly becoming a "must visit" venue for world-class rowers in the U.S.

In Fort Worth, Chesapeake's million-dollar pledge to the Museum of Science and History will provide funds to build an exhibit commemorating the important role energy has played in the state of Texas for more than 100 years. Students will learn firsthand the career opportunities afforded them in this challenging, high-tech industry that is a major and growing contributor to Fort Worth's booming economy through the wealth the Barnett Shale's rapid development is creating.

Since a large portion of Chesapeake's business model is rooted in rural areas where the majority of our drilling rigs operate, the company places great emphasis on improving life outside of major metropolitan areas. Hundreds of Chesapeake employees are actively involved in local governments, schools, volunteer fire departments and a myriad of other benevolent activities. Chesapeake supports dozens of initiatives to improve safety and well-being, regardless of the size of the community.

As an example of this commitment, Chesapeake supported the "Live at Lincoln" concert series launched last fall in Hamlin, West Virginia (population 1,114). Commitment to the arts is an important part of any community's development, and this new program makes great strides to enriching the quality of life for people in and around Hamlin. Chesapeake's donation is expected to increase tourism and serve as a catalyst for economic development while exposing young and old to great classical musical performances.



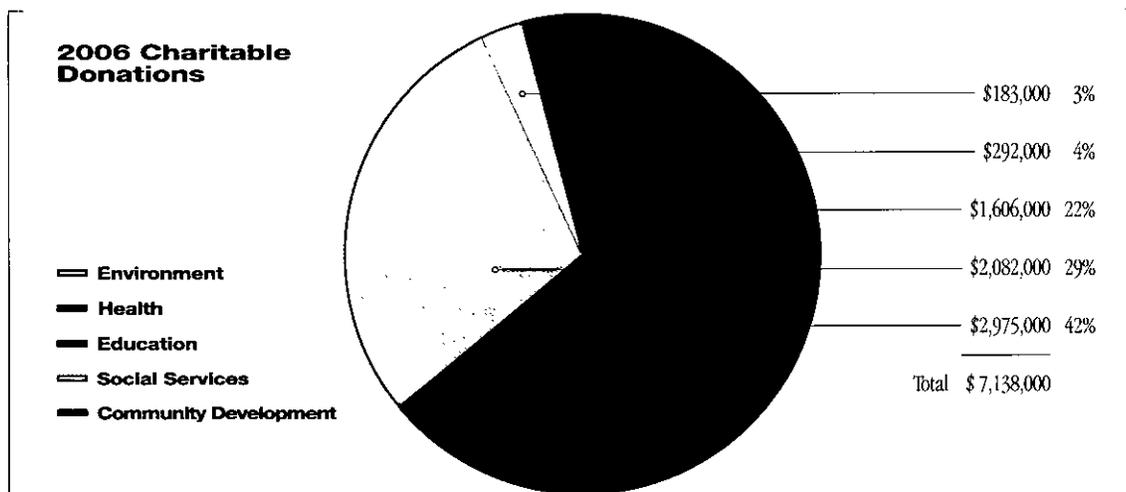


The \$3 million Chesapeake Boathouse is the initial development along the long-ignored Oklahoma River and has served as a catalyst for economic development along the riverfront and downtown Oklahoma City.

Our company's community service strategy includes identifying needs, determining the opportunities for building sustainable alliances to meet those needs, and then establishing productive partnerships with groups that have the expertise and commitment required to ensure our support will have a material impact. Targeting community service commitments in this manner provides the most positive returns on our considerable charitable investments.

Chesapeake's employees recognize they are fortunate in many ways. In turn, they make genuine efforts to serve as positive role models in the workplace and in their communities. In 2006, charitable support through Chesapeake helped communities throughout our operating areas raise a record \$7 million dollars in charitable donations.

In addition to generous giving, Chesapeake employees in every state of our operations volunteer their time and talents in hundreds of community programs: wielding hammers for Rebuilding Together and Habitat for Humanity, running in charity marathons, coaching youth athletics, and shaving their heads to support children's cancer research. The company appreciates the generosity and compassion of its employees and applauds their efforts to enhance the lives of their friends and neighbors.



Economic Development Commitment

Few factors improve the quality of life in a community, state or country more than the creation of high-quality jobs. Chesapeake is proud that we have developed more than 2,400 jobs in the past year alone. At year-end 2006, we employed almost 5,000 dedicated and talented people across our 16-state operating area. Since 2000, our work force has expanded nearly 1,000%, enabling Chesapeake to reach our growth objectives and efficiently conduct the nation's most active drilling program.

Chesapeake is dedicated to exploring and producing clean-burning natural gas for American homes and industries while growing the value of our stakeholders' investments. As we accomplish these goals, our company also strives to create challenging and rewarding jobs for our employees, to serve as a responsible steward of the environment and to enhance the quality of life in the communities and states where we work, live and play.

Health, Safety and Environment (HSE)

Protecting the health and safety of our employees is of critical importance to Chesapeake. We are equally committed to protecting the world in which we live, work and play by meeting or exceeding environmental compliance regulations throughout our operating areas. To demonstrate these commitments, the company has a growing array of comprehensive programs to ensure our employees work safely and protect and enhance the environment.

Employee Health and Safety Commitment

Helping our employees become and stay healthy is a key strategy to help boost productivity and make Chesapeake an employer of choice. In our ongoing effort to promote good health, we have initiated a number of wellness programs in our operating units and at our Oklahoma City corporate headquarters to increase productivity and lower health care costs. In Oklahoma City, a 42,000-square-foot state-of-the-art health facility provides employees and families with convenient access to the latest health equipment and group exercise classes. Chesapeake also subsidizes family fitness center membership fees for employees in the field.

In 2006, Chesapeake introduced our employees to the Living Well program, which offers financial incentives to employees to achieve and maintain healthy and productive lifestyles through education, motivation and intervention. The program's success was so great, this year Living Well has been extended to include field office employees. Today, more than 1,500 employees, a third of whom work in field locations, are enrolled in the program.

Chesapeake has recently been admitted to an elite group of organizations that make up the Health Enhancement Research Organization (HERO). HERO is a nationwide, research-based coalition of organizations with common interests in health promotion, disease management and health-related productivity research. Chesapeake is proud to join the HERO coalition, which is striving to shift the paradigm from a health system focused only on diagnosis and treatment to one that focuses on prevention and productivity.



At Chesapeake, we place a great deal of importance on providing safe work environments for our employees, both in office and field locations. Equally important is our commitment to ensuring the safety of those around us by continually reviewing and improving our drilling operations. In 2006, the number of Chesapeake employees participating in safety and environmental training programs increased by almost 30%. In addition to regular operational training, employees in field facilities also attended an average of 24 hours of specialized safety and environmental training. The company is making such programs accessible to all employees by providing a multitude of training venues, from one-on-one instruction to on-site meetings, classroom training and online instruction systems.

Environmental Commitment

Chesapeake is committed to conducting our operations with care for the environment. The company's goal at every well it drills is simple – minimize the environmental impact at the drilling site, now and in the future. As we explore for and produce natural gas, we demonstrate our respect for the needs of the people and creatures with whom we share this planet and for the generations who will follow.

Natural gas represents 91% of Chesapeake's production and is the cleanest-burning, most environmentally responsible conventional energy source, emitting lower levels of the greenhouse gases that contribute to acid rain and global warming. Increasing the use of natural gas as a preferred energy source for residential, commercial and industrial purposes is a significant tool in the goal to reduce overall pollution levels.

Environmentally Friendly Operations

At Chesapeake, we are proud to be a leading producer of the cleanest-burning conventional energy source. This pride is evidenced by the way we conduct our operations. Each well we drill and operate must comply with a host of regulations promulgated by federal, state and local regulatory agencies. With more rigs running than any other E&P company in the nation, Chesapeake acknowledges and embraces the great responsibility that accompanies our success.



Chesapeake drills in a wide variety of environments, from densely populated cities to farmlands to wilderness areas. At each site, the company adapts its operations to protect and preserve the environmental integrity of the area. "Choose wisely and plan well" is the corporate directive our drilling and production professionals follow diligently to guide them through the processes of wellsite selection, drilling and production in every operating region.

Small Footprints

Having well-informed, committed people in the field is a key element to sustaining environmentally acceptable operations. The company has environmental education programs in place for field employees and encourages all employees to participate. Their efforts are assisted by programs such as our Geographic Information System. This innovative online database provides site-specific information about the presence of bodies of water, endangered species habitats and proximity to wildlife preservation areas before selection teams ever set foot on a prospective wellsite.

Leading-edge drilling techniques are being put to new uses as Chesapeake ramps up activities in the Fort Worth Barnett Shale of north-central Texas, in what may become the largest urban drilling program ever undertaken. Continually improving horizontal drilling and multiple well pad drilling technologies enable the company to drill more productive wells while reducing our environmental footprint.

Neighborhood-friendly operations in highly populated areas such as in the Fort Worth metropolitan area require the use of effective noise control methods as we drill, complete and produce wells. Chesapeake is a noise abatement pioneer in the Barnett, conducting our own noise sampling and implementing the strongest measures possible to reduce noise, which may involve retrofitting existing rigs at the same time we design quieter new-generation rigs.

Finally, Chesapeake's "Good Neighbor Initiative" promotes helpful dialogue between landowners, lessees, permit holders and residents of producing areas. This successful program, developed in our New Mexico operations, is now being introduced into the Fort Worth area. It pledges the responsible development of energy resources, along with environmental stewardship and respect for property rights.

Public Lands

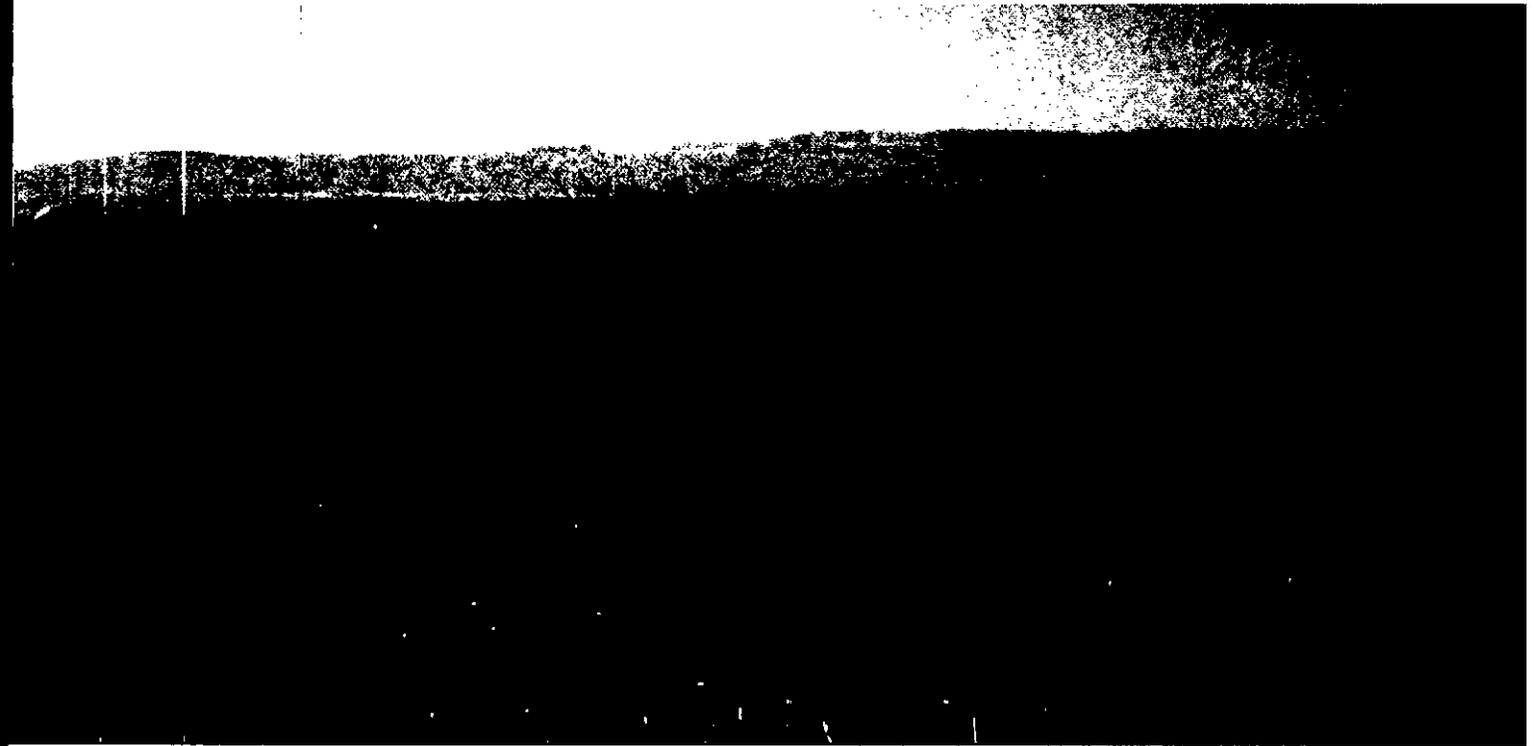
While the majority of the company's activities are conducted on privately owned land, Chesapeake does occasionally explore for and produce natural gas on public lands. There, we consistently meet or exceed some of the most complex environmental regulations in the world. In each of these public areas, we implement a multitude of best practices, such as closed-loop drilling mud systems to reduce the impact of our operations. We believe Chesapeake's track record on public lands is another visible demonstration of our concern for the environment and motivates us to be a better operator everywhere we drill.

For example, as we begin development in the Davy Crockett National Forest of east Texas, the company is working closely with the U.S. Forest Service, which has applauded our efforts. Each potential wellsite goes through a rigorous assessment process that includes evaluations of wildlife habitats, possible impact on wetlands and trees, and archeological studies.

Water

In every state where we operate, Chesapeake recognizes the need to conserve water and protect groundwater resources. We typically use safety measures, including surface casing and conductor pipe, to ensure the integrity of freshwater formations. We isolate and safely dispose of any saltwater produced during the drilling process.

The company is keenly aware of our role as stewards of the environment when we grow through acquisitions. Chesapeake has established a highly regarded reputation for planning and executing immediate improvements on acquired wellsites, bringing them up to company-wide standards as well as government compliance levels.



Tallgrass Prairie Preserve photo courtesy of The Nature Conservancy

Supporting Environmental Initiatives

Building strong relationships with private, nonprofit and public partners is another key element of environmentally friendly operations. A Chesapeake manager has chaired the Bureau of Indian Affairs/Bureau of Land Management Working Group, an industry/governmental organization whose goal is to improve understanding and communications between the natural gas industry and government land management and regulatory agencies and to facilitate interagency communications.

Chesapeake is also a founding member of the Low Impact Natural Gas and Oil project in Arkansas, a collaborative effort to develop a web-based decision-support tool that will enable energy companies and regulatory agencies to share education and integration systems while promoting better communications.

The company continues its multiple commitments to industry and nonprofit environmental groups such as the Oklahoma Energy Resources Board, which has remediated more than 6,000 abandoned wellsites across the state at no cost to taxpayers. We are now Oklahoma's largest financial contributor to this program and in 2006 our contributions were over \$500,000. We also are a supporter of educational outreach programs conducted by the Oklahoma Association of Conservation Districts, providing cash awards to educators and districts who record outstanding achievements in environmental education.

In addition, Chesapeake partners with The Nature Conservancy, sharing its mission to preserve the plants, animals and natural communities that represent the diversity of life on earth by protecting the lands and waters they need to survive. This long-term partnership has had lasting and beautiful results, such as restoration of the 38,000-acre Tallgrass Prairie Preserve in north-central Oklahoma.

Chesapeake continues to place health, safety and environmental management among our highest priorities, because HSE programs improve the quality of work life of our employees while adding value for investors.

CHK's Officers



Aubrey K. McClendon 1
Chief Executive Officer and Chairman

Marcus C. Rowland 2
Executive Vice President
and Chief Financial Officer

Steven C. Dixon 3
Executive Vice President Operations
and Chief Operating Officer

Douglas J. Jacobson 4
Executive Vice President
Acquisitions and Divestitures

J. Mark Lester 5
Executive Vice President
Exploration

Martha A. Burger 6
Senior Vice President
Human and Corporate Resources

Jeffrey A. Fisher 7
Senior Vice President
Production

Jennifer M. Grigsby 8
Senior Vice President
Treasurer and Corporate Secretary

Henry J. Hood 9
Senior Vice President
Land and Legal and General Counsel

James C. Johnson 10
Senior Vice President
Energy Marketing

Michael A. Johnson 11
Senior Vice President
Accounting, Controller
and Chief Accounting Officer

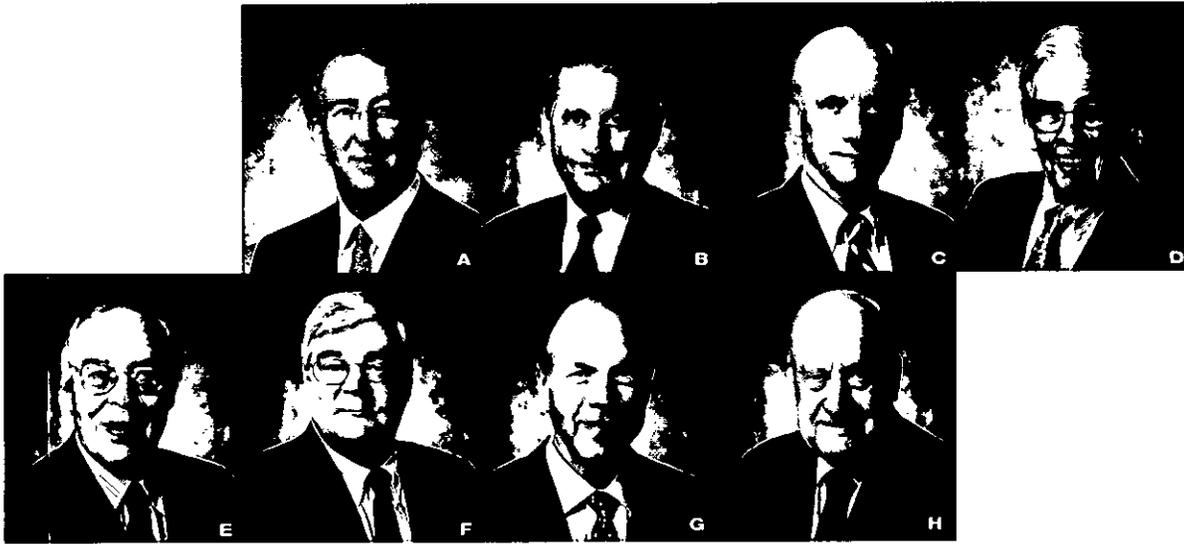
Stephen W. Miller 12
Senior Vice President
Drilling

Jeffrey L. Mobley 13
Senior Vice President
Investor Relations and Research

Thomas S. Price, Jr. 14
Senior Vice President
Corporate Development

Cathy L. Tompkins 15
Senior Vice President
Information Technology

CHK's Directors



Aubrey K. McClendon **A**
Chairman of the Board and
Chief Executive Officer
Oklahoma City, OK

Richard K. Davidson **B**
Former Chairman of the Board
Union Pacific Corporation
Omaha, NE
(1,3)

Frank Keating **C**
Former Governor, Oklahoma
President and CEO
American Council of Life Insurers
Washington, DC
(2,3)

Breene M. Kerr **D**
Private Investor
Easton, MD
(1)

Charles T. Maxwell **E**
Senior Energy Analyst
Weeden & Co.
Greenwich, CT
(2)

Merrill A. "Pete" Miller, Jr. **F**
Chairman, President and CEO
National Oilwell Varco, Inc.
Houston, TX
(1)

Don Nickles **G**
Former U.S. Senator, Oklahoma
Founder and Principal
The Nickles Group
Washington, DC
(1)

Frederick B. Whittemore **H**
Advisory Director
Morgan Stanley
New York, NY
(2,3)

(1) Audit Committee

(2) Compensation Committee

(3) Nominating and Corporate Governance Committee

Corporate Governance

Our Board of Directors is responsible to our shareholders for the oversight of the company and for the implementation and operation of an effective and sound corporate governance environment. We believe that effective corporate governance contributes to long-term corporate performance. An effective governance structure should reinforce a culture of corporate integrity, foster the company's pursuit of long-term strategic goals of growth and profit, and ensure quality and continuity of corporate leadership. Our directors will continue to be diligent in their efforts to preserve the public trust while fostering the long-term success of the company.

Our People 4,883 Strong

As of December 31, 2006, and sorted alphabetically by year of hire

1989 (4)

Mark Lester
Kinney Louthan
Aubrey McClendon
Patsy Waters

1990 (5)

Kevin Decker
David Higgins
Linda Peterburs
Cindi Williams
Jeff Williams

1991 (11)

Steve Dixon
Wes Kruckenberg
Joe McClendon
Marilyn Pollard
Patti Schlegel
Vivian Smith
John Striplin
Randy Summers
Julie Washam
Clarence Watts
LuAnn Wernli

1992 (3)

Tom Price
Melanie Weaver
Ken Will

1993 (8)

Ralph Ball
David Desalvo
Rick Hughes
Charles Imes
Mike Johnson
Randy Pierce
Marc Rowland
Dave Witzman

1994 (19)

Barbara Bale
Martha Burger
Michael Coles
Traci Cook
Ron Goff
Darvin Knapp
Greg Knight
Dan LeDonne
Felipe Maldonado
Steve Miller
Tommy Morphew
Pat Pope
Bobby Portillo
Danny Rutledge
Stephanie Shedden
Ronnie Ward
Janet Weeks
Shelly White
Gerald Zgabay

1995 (37)

Richey Albright
Paula Asher
Eric Ashmore
Randy Bortaug
Shelli Butler
Leon Carmona
Ilan Cathey
Melissa Chambers
Dale Cook
Ted Davis
Mandy Duane
Kyle Essmiller
Steve Gaskins

Jennifer Grigsby
Cliff Hanoch
Gayle Harris
Mike Hazlip
Carol Holden
Henry Hood
Lorrie Jacobs
Mike Johnston
Jesse Langford Jr.
Bary Langham
Cindy LeBlanc
Sandy Mathis
Leland Murray
Fred Portillo
John Qualls
Pat Rolla
Hank Scheel
Charles Scholz
Charlie Smith
Stan Simmet
Brenda Stremble
Greg Weinschenk
Brian Winter
Jimmy Wright

1996 (38)

Heather Anderson
Judy Arias
Janie Carter
Jasen Davis
George Denny
Tim Denny
Gary Dunlap
Laurie Eck
Jan Fair
Barbara Fratley
Linda Gardner
Charlene Glover
Randy Goben
Jim Gomez
Melissa Gruenewald
Doug Johnson
Jim Johnson
Susan Keller
Taylor Kemp
Sandi Lagacy
Mike Lebsack
Steve Leprete
Janet Lowrey
Larry Lunardi
John Marks
Carrol McCoy
Sondra McNeiland
Liz Muskrat
Angela Ports
Buddy Powell Jr.
Tommy Putz
Kim Rogers
Bryan Sagebiel
Kurt Schrantz
Ricky Scruggs
Phyllis Trammell
Joe Vaughan
Allan Waldroup

1997 (36)

Linda Allen
Karla Allford
Sara Caldwell
Steve Cody
Kristine Conway
Randy Cornelisen
Michelle Cullen
Bruce Dixon
Greg Drownski
Mark Evans
Joy Franklin
Rob Gilkes
Kim Ginter
Tony Gore

Shane Hamilton
Michael Horn
Eric Hughes
David Jones
Mike Ludlow
Sarah Lumen
Lauren Matlock
Sam McCaskill
Bob Neely
Bob Pope
Erick Porter
Les Rodman
Jolene Schur
Carolyn Simmons
April Smith
Wilma Smith
Lynda Townsend
Frank Unsicker
Ivraean Wallace
Craig White
Don Williams
Curtis Williford

1998 (74)

Stephen Adams
Grae Ban
Francy Beesley
Joel Bennett
Leonard Berry Jr.
Susan Bradford
Wade Brawley
Mark Brown
Randy Brown
Lori Budde
Ken Bynum
Terry Caldwell
Bob Campbell
Ted Campbell
Jesse Canaan
Sherri Childers
Jennifer Copeland
David Craycraft
Kim Doty
Iris Drake
Mac Drake
Don Dunn
Gary Egger
Steve Ernick
Dan Estes
Gary Finn
Charles Floyd
Jennis Frick
Randy Gassaway
Stacy Gilbert
Gena Goodwin
Jim Gowens
Tana Griggs
Kelsey Hammit
Tresa Hammond
Jeff Harris
Debbie Hulet
Julie Ingram
Tammy Kellin
Rose Kim
Steve King
Mike Lancaster
Chris Lee
Carrie Lewis-Crawford
Craig Madsen
John Marshall
Kim Massey
Allen May
Dennis McGee
Allen Miller
Bill Miller
Carey Milligan
David Mobley
Wes Myers
Bud Neff Jr.
Kathy Nowlin
Don Pannell

Michael Park
Mandy Pena
Matt Rockers
Kelly Ruminer
Dan Scott
Greg Small
Bill Snyder
George Soto
Edward Puffinbarger
Mike Sawatzky
Cindy Schwiager
Brent Scruggs
Vance Shires
Stuart Skelton
David Smith
Sandra Smith
Shelby VanWinkle
Rusty Walker
Lynn Whipple
Mandy Whipple

1999 (28)

Jonathan Ball
Mel Barker
Sue Black
Dory Douglas
Mark Edge
Jenny Ferguson
Jeanie Fuller
Dan Garvey
Susan Green
Yamei Hou
Doug Jacobson
Melissa Jarvis
Jim Kelley
Steve Lane
Lynn Looper
Dea Mengers
Michael Miller
David Murray
Tammy Nguyen
Lacosta Rawls
Tom Brennan
Van Brinkley
Deanne Brooks
Marty Byrd
Carlos Caraveo
Bill Carter
Keith Case
Marika Chambers
Kristi Clemmens
Tim Cloud
Kyle Cole
John Cook
Tim Cook
Juanita Cooper
Jim Corsoro
Leigh Ann Crain
James Cropp
Brian Cunningham
Garry Curry
Shawn Downey
Jeff Eager
Richard Easterly
Tommy Edler
Amanda Elam
Brian Edline
Kristin Fitzgerald
Alex Gallardo Jr.
Matt Gambill
Roy Gentry
Suzie Goolsby
Richard Grayson
Randy Green
Kajsa Greenhoward
Kajsa Gross
Johnny Harris
Melanie Hayhurst
Shannon Henderson
Michael Hodges
Jeremiah Jackson
Krista Jacobson
Justin Johnson

Collin McClath
Greg McMahan
Courtney Moad
Georgia Moller
Nathan Morrison
Mecca Osban
Edward Puffinbarger
Mike Sawatzky
Cindy Schwiager
Brent Scruggs
Vance Shires
Stuart Skelton
David Smith
Sandra Smith
Shelby VanWinkle
Rusty Walker
Lynn Whipple
Mandy Whipple

2001 (126)

Sharlot Abernethia
Jerry Aebi
Karen Albornoz
Granford
Jenney Allison
David Anderson
Terry Ashton
Betsy Ball
Gloria Bates
Michelle Bender
Bruce Boeckman
Boyce Boelen
Sharon Bradford
Tom Brennan
Van Brinkley
Deanne Brooks
Marty Byrd
Carlos Caraveo
Bill Carter
Keith Case
Marika Chambers
Kristi Clemmens
Tim Cloud
Kyle Cole
John Cook
Tim Cook
Juanita Cooper
Jim Corsoro
Leigh Ann Crain
James Cropp
Brian Cunningham
Garry Curry
Shawn Downey
Jeff Eager
Richard Easterly
Tommy Edler
Amanda Elam
Brian Edline
Kristin Fitzgerald
Alex Gallardo Jr.
Matt Gambill
Roy Gentry
Suzie Goolsby
Richard Grayson
Randy Green
Kajsa Greenhoward
Kajsa Gross
Johnny Harris
Melanie Hayhurst
Shannon Henderson
Michael Hodges
Jeremiah Jackson
Krista Jacobson
Justin Johnson

Keith Johnson
Rob Jones
John Kapchinske
Ginni Kennedy
David Kidd
Edward Killen
Julie Knox
Daniel Kochn
Kenneth Lee
Jeff Lenocker
Julia Lillard
Darwin Lindenmuth
Steven Logue
Travis Long
Peter Manter
Rita Marple
Jim Mazza
Kenny McGuire Jr.
Jim McHenry
Debbie McKee
Mick McMurphy
Don Messerly
Don Miller
Bobby Mitchell
J. C. Morris
Melinda Neher
Lee Nelson
Kevin Newberry
Tim Newville
Deborah O'Neal
Daron Patterson
Ricky Petty
Dianne Pickard
Catherine Radloff
Lynn Regouby
Gina Romano
John Romine
Larry Ross
Steve Ross
Don Rozzell
Lindsay Seaman
Larry Settle
Mike Shklar Jr.
Kristin Sipe
Johnnie Smith
Patrick Smith
Dee Smith Jr.
Chris Sorrells
Dennis Splan
Jason Stamper
Cindy Stevens
Bill Stillwell
Gary Stoner
Howard Stout
Lisa Strackbein-Carlson
Tim Taylor
Jason Thaxton
Alvin Thomas
Rudy Thomas
James Thrash
Paul Waits
Larry Watters
Johnny White
Paige Whitehead
Jim Wilkinson
Connie Williams
Freda Williams
Dawn Wilson
Brandon Winsett
Marvin Winter Jr.
John Yelverton
Amanda Young

2002 (181)

Nicole Adams
Jenny Aulkins
Roger Aldrich
Jimmy Alexander
Stephen Armer
Brian Babb

Charlie Bagley
Megan Bain
Bob Baker
Lynard Barrera
Cindy Barrios
Shane Barron
Dennis Bass
James Beavers
Stephen Benham
Randy Bergen
Leonard Blackwill
Thomas Blanco
Paul Bowyer
Troy Bradford
Robert Bradley
Don Bredy
Tammy Brewer
Lindell Bridges
Jim Brock
Cindy Brown
Kathy Brown
Lynn Broyles
Jason Budde
Greg Burchett
Aaron Bush
Emil Byrd
Steve Campbell
Cindy Carden
Chris Carter
Paul Childers
Jackie Cooper Jr.
Lori Crabtree
Cary Crusinberry Jr.
James Davis
Kurt Davis
Cathy DeGiusti
Trent Delano
Cheryl Delzer
Larry Dill
Sherry Dixon
Christopher Dudgeon
Stephanie Dugan
Bryan Dunn
Eldon Eagan
Eric Edwards
Michael Falen
Mark Falk
Shawn Fields
Tom Flesher
Viel Flores
Justin Foust
Adam Gaskill
Tamara Gathers
Fred Gipson
Cornelio Gomez
Eleuterio Gomez-Martinez
David Gouker
Steve Hall
Melvin Harper
Heidi Havenstrite
Abe Henry
John Henry
Kathy Henry
Jarvis Hensley
John Hornsby
Debi Huff
Ralayna Hurley
John Hurst
Todd Lee
Rhonda Ingle
Bud Jackson
Jay Jarvis
Danny Jech
Jim Jenkins
Gary Johnson
Holly Johnson
Roy Johnson
William Johnson
Chris Jones
Joe Jones
Robin Jones

James Keathley
Mike Kee
Dax Kimble
Nancy Knox
Greg Kochenower
Jeremie Koehn
John Kutz
Spencer Land
Steve Larman
Ricky Laster
Sarah Ledgerwood
Casidy Lee
Ken Leedy
Paula Lillard
Stephen Lobaugh
Billy Long
Shawn Marsh
Steven Martin
Richard Martinez
Randy Masters
Andrew McCalmont
Dusty McDaniel
Mitch McNeill
Lisa Meier
Richard Mieser
Nikki Miller
Steve Mills
Sidney Mitchell
Claudia Molina
Ciferentes
Amber Morrison
Todd Murphy
Jeff Newby
Miguel Nunez
Rick Nunley
John Ortiz
David Parker
Robert Pennel
Ryan Phillips
Sharon Pool
Bob Portman
Eric Powell
Lloyd Puffinbarger
Mike Reddick
Ronald Reidle
Lisa Roberts
A.D. Robison
Maureen Roden
Vern Roe Jr.
Brandon Rutledge
Danny Schmidt
Kary Scheiberger
Stacy Settles
Jeff Sharp
Dewayne Shaw
Michael Sherwood
Will Shister
Jim Shoptaw
Mark Singleton
Greg Skiles
Chad Smith
Jesse Smith
Duff Snow
Maria Strain
Josh Swift
Oscar Thiems
Diana Thompson
Leonard Thurber
Oleg Tolmachev
Jerry Townley
Chris Townsend
Michelle Townsend
Ryan Turner
Rodney Vaeth
Fred Vasquez
Ruben Vega Jr.
Don Vermillion
Al Warner
James Warner
Michael Weese
Hazel Welch
Leslie Wertz

2003 (281)

Ronald Aaron
Pat Abala
Lisa Bagwell
Corky Baker
Jim Ball
Staci Barentine-Bogle
Charlie Bateman
Travis Bates
Tyler Beaver
Mike Bechtel
John Biggs
Johnny Boland
Bruce Bony
Tammi Bradford
George Bradley
Kim Brady
Serena Branch
Cyndy Brannon
Jerry Bray
Aron Bridges
Jennifer Broomfield
Bryan Brown
Jeff Brown
Maria Brown
Heather Brunker
Kenneth Brunson
John Bullard
Bayley Burns
Cindy Burns
Busier Burton Jr.
Ara Bush
Lori Byrd
Tami Caldwell
Keith Cameron
Bob O. Campbell
Joe Campbell
Pat Carson
Gary Carter
Dennis Gerry
David Chrisom
Andy Christensen
Mike Churchwell
Tony Clark
Michael Clinton
Todd Coates
Amanda Colbert
Matthew Colbert
Karen Cook
Tom Corley
Bryan Cox
Brian Cox Jr.
Michael Cramer
Ann Croan
Jarod Cunningham
Wendy Cunningham
John Davis
Ryan Davis
Kenneth Davis
Ryan Dean
Santiago Diaz III
Scott Dickson
Dennis Dixon
Derek Dixon
Steve Donley
Sharon Dries
Sharon Dunlap

Jody Dunn	Dustin Locke	Kelly Shipley	Curtis Blake	Evelyn Daniel	J. D. Herweck	Kelly McConnell	Dustin Roadifer	Bryce Ward
Gary Durkee	George Loman	Aaron Siemers	Tiffany Blalock	Jennifer Davis	Melissa Heusel	Duane McDowell	Gary Robbins	Keith Washington
Jack Elliott	Clini Lord	Jen Sims	Lorraine Blanchard	Roger Jasion	Holly Hicks	Mike McGinnis	Bill Roberts	Brandon Watson
Jimmy Embury	Jay Lowrey	Kam Smalls	Kelsey Blendin	John Dav	Alvin Highfill	Donna McGriff	Zac Rodriguez Jr.	Chaney Watts
Charlene Ernest	Jack Lowry	Stacy Smith	Bradley Blevins	Robbie Dean	Kevin Hill	Natalie McNeil	Chip Roemisch Jr.	Cindy Wegener
Keith Ervin	Sergio Lujan	Joe Southern Jr.	Lee Blevins	Luke Del Greco	Danny Hink	Ryan McNeil	Dick Rosencrans	Kyle Welcher
Jim Fansher	Shane Lukasek Jr.	Kristina Stacey	Aaron Bloodow	David Delao	Theresa Hodje	Theresa McNulty	Kelly Rother	Mike Whitefield
Ursula Faus	Sharon Luttrell	Blake Stacey	Courtney Blood	Misty Dickson	Buz Holloway	Cliff Merritt	Jay Ryel	Patrick Whitman
Carol Fehrenbacher	Lewis Lynch	Johnny Stanford	Elizabeth Bohanan	Kelly Dobbis	Julie Holt	Matthew Milledge	Ricky Salinas Jr.	Amanda Whitmore
Mark Ferbrache	Mark Mabe	Joyce Stannire	Deborah Bond	Johna Dodson	Latania Holt	Pat Mills	Amy Sanders	Dustin Whitmore
Jeff Fisher	Ali Mallett	Scott Stearman	Brian Booker	Kirk Dougherty	Alan Horton	Sheldon Mills	Mary Ann Sanders	Mike Wiberg
David Fies	Clayton Manhart	Rick Strong	Tad Boone	Dustin Drew	Doug Howeth	Rodolfo Molina	Larry Satterfield Jr.	Tom Wible
Mitch Floresca	Jeremy Marple	Luke Strickland	Kristin Bottom	Will Hubbard	Chuck Duginski	Elton Monroe	Perry Scheffler	Jackie Wicks
Tommy Foust	Shelly Martin	Michelle Sturatt	Thomas Boucher	Keith Dudley	Thomas Boucher	Kendra Monroe	Peter Scheffer	Andy Widmer
T. R. Fox	Alfredo Martinez	Blake Surrall	Angela Bouwware	Chuck Duginski	Angela Bouwware	Penny Montgomery	Brandon Schreck	Leon Wildman
Justin Froehlich	Alex McCalmont	Blake Surrall	David Bowes	Lorrie Dunn	David Bowes	Dana Moore	Terry Scires	Ann Williams
Edd Gabban	Reid McCarty	Kelsey Swinford	Darrel Branson	Chad East	Darrel Branson	Sieve Moore	Joel Scott	Randy Williams
Fred Gagliardi	Paul McGolgan	Danielle Sydnor	Rudy Bravo Jr.	Peggy Elliott	Rudy Bravo Jr.	Adria Morgan	John Seldenrust	Antoine Wilson
Tim Gallegly	Jay McGuffee	Jaime Tatro	Avis Bray	Adam Hutchinson	Avis Bray	Sim Morgan	Juan Serna	Kelly Wilson
Adam Gardner	Kenneth McGuire Sr.	Amber Thomas	Jeff Bray	Mark Hylton	Jonathan Esparza	Jimmy Morris	Steve Serna	Tyler Wilson
Travis George	Carol McKenzie	Chevy Thomason	Roxi Brill	Elisa Mount	Carlos Evans	Elisa Mount	Auggie Setiadarma	Dave Winchester
B.K. Gibson	Tara McKenzie	Donna Thompson	Robin Evans	Beth Mullenix	Donna Thompson	Beth Mullenix	John Sharp	Robb Winfield
Kenneth Gideon	Ryan Meacham	Joyce Stannire	Sheila Even	Mark Murray	Jerry Todd	Mark Murray	Jack Shaver	Jeff Wolf
Dana Ginanni	Randy Mefford II	Jerry Todd	Terri Bristow	Tim Murray	Scottie Trejo	Tim Murray	Tim Murray	Tom Wollenberg
John Gist	Eddie Merkel	Scottie Trejo	Darren Brittain	Chuck Myers	Karen Trowbridge	Chuck Myers	Gene Shepard	Jerry Womack
Randy Gladden	R.T. Miller	Karen Trowbridge	Mark Broadus	Todd Nance	Seth Unruh	Jayson Jones	Kyle Shipley	Dana Woo
David Godsey	Brent Mills	Jon Vanburen	Anita Brodrick	Michael New	Jon Vanburen	Amanda Jeantet	Paul Skilton Jr.	Carla Wood
Jeff Gorton	Jay Monroe	Julio Vasquez	Donald Bromlow	Nick Newland	Jay Monroe	Jessica Jennings	Stacy Slater	Julie Woodard
Liz Gotcher	Alfredo Montiel	Larry Ventris	Marc Ferguson	Rich Newton	Alfredo Montiel	Sam Johnson	Julie Slaton	Craig Woodruff
Jim Govenlock	Lucetia Morris	Johnny Voth	Dustin Fick	Greg Northern	Lucetia Morris	Christie Brown	Kirsten Smedley	Harold Wooley
Larry Grey	Huey Morton	Buddy Wade	Daniel Fick	Matthew Nowlin	Huey Morton	Buddy Wade	Clay Smith	Landon Worth
Jimmy Haddick	Larry Mossman	Keith Wagnon	Jeff Finnell	Karyn Olschesky	Larry Mossman	Diana Brown	Mark Smith	Jill Wray
Pablo Hadzgriga Jr.	Paul Munding	Mary Wall	Jarod Fite	John Keeling	Pablo Hadzgriga Jr.	Harlan Brown	Montie Smith	Jose Yanez
Paul Hagemeyer	Maureen Nelson	Josh Wangler	Jason Brown	Kasey Keeny	Paul Hagemeyer	Jason Brown	Shery Orahood	Frank Ybarra
Buck Hall	Jason Nichols	Brad Watkins	Pamela Brown	Shamara Keith	Buck Hall	Pamela Brown	Jacy Osburn	Mark Yetsley
Michael Hall	Jane Ann Norris	Ronnie Brown	Ronnie Brown	Lindsay Keller	Michael Hall	Ronnie Brown	Steven Owen	Gail Spencer
Cameron Han	Tal Oden	Travis Brown	Travis Brown	Earnest Kelough	Cameron Han	Travis Brown	Lindsey Pargeter	Robert Sperandio
Ronnie Haney	Mececa Oliphant	Aaron Buchanan	Aaron Buchanan	Bobby Kepley III	Ronnie Haney	Aaron Buchanan	Glenn Parker	Terry Stafford
Jessie Hardin	Tony Olivier	Craig Buck	Craig Buck	Bill Kerby	Jessie Hardin	Craig Buck	Michael Parker	Samuel Staggs Jr.
Graham Harris	Rena Owen	Andy Fritsch	Andy Fritsch	Jennifer Kem	Graham Harris	Andy Fritsch	Ryan Parman	Daryl Stallings
Lisa Harris	Ashley Paine	Terry Frohnapfel	Terry Frohnapfel	David Kimmel	Lisa Harris	Ashley Paine	Walther Patten	Steve Stealham
Roger Harrod	Tobin Paris	Ronald Garbizo	Ronald Garbizo	Neel Kincade	Roger Harrod	Tobin Paris	Deone Peary	Joe Stewart
Rich Hears	Nancy Parker	Gary Garrison	Gary Garrison	Kizzy Kirk	Rich Hears	Nancy Parker	Chris Pennel	Pete Stewart
Pancho Hendricks	Gary Parks	John Garrison	John Garrison	Jason Kneedy	Pancho Hendricks	Gary Parks	Andrea Penner	Neal Stinson
Tara Henry	Gale Parman	Juan Gaskill	Juan Gaskill	Brenda Knight	Tara Henry	Gale Parman	Raymond Perez	David Stone
Glen Hensley	Kellie Patterson	Paul Geisinger	Paul Geisinger	Brett Knight	Glen Hensley	Kellie Patterson	Dwain Peterson	Travis Stout
Sue Ann Henthorn	Randy Patterson	Christie Cantrell	Christopher Cantrell	Jennifer Knight	Sue Ann Henthorn	Randy Patterson	Terry Phillips	John Stoute Jr.
Catherine Hester	Donnie Patton Sr.	James Cantwell	James Cantwell	Josh Komarek	Catherine Hester	Donnie Patton Sr.	Randy Pierce	Tom Stovall
Terry Hodgson	Andrea Patzkowsky	Larry Carter	Larry Carter	Matt Kopf	Terry Hodgson	Andrea Patzkowsky	Stacie Prinion	Bob Streeter
John Hogan	Michael Phillips	Lupe Castro	Lupe Castro	Pam Koscinski	John Hogan	Michael Phillips	Cody Pitts	Travis Striplin
Lanny Holman	Ronnie Pitts	John Glyn	John Glyn	John Kuciewicz Jr.	Lanny Holman	Ronnie Pitts	Dennis Piernons	Jason Sutterfield
Misty Holtgreve	Brent Pleicher	Jason Goff	Jason Goff	Shaun Lambert	Misty Holtgreve	Brent Pleicher	Keith Plumlee	Mark Szymore
Paul House	Esta Pleicher	Richard Gonzales	Richard Gonzales	Joel Porter	Paul House	Esta Pleicher	Joel Porter	Barry Tarman
Brian Howard	Jerry Preston	Linda Good	Linda Good	Donnie Latham	Brian Howard	Jerry Preston	Bryan Potter	Joseph Tarver
Roy Howe	Regan Raff	Michael Goossen	Michael Goossen	Cory Lewis	Roy Howe	Regan Raff	Janae Power	Ray Taylor
Donna Huff	Ken Rechlin	Michael Gorman	Michael Gorman	Shea Lewis	Donna Huff	Ken Rechlin	Kelly Price	Jon Terrell
Rosie Hutton	Wes Redding	Jennifer Granger	Jennifer Granger	Jason Lierle	Rosie Hutton	Wes Redding	John Priest	Gerald Thomas
Angela Ingargiola	Bart Reece	Justin Gray	Justin Gray	Brent Lightsey	Angela Ingargiola	Bart Reece	Flo Prieto	Randall Thomas
James Inman	Jim Reisch	Angie Green	Angie Green	Melvin Like	James Inman	Jim Reisch	Josh Purcell	Renee Thomas
John Jackson	Katherine Rhynes	Suzanne Green	Suzanne Green	Darwin Lime	John Jackson	Katherine Rhynes	Odie Quigley	Robert Thompson
Andrew Jarrett	Mindi Richardson	Coty Greer	Coty Greer	Curt Locklar	Andrew Jarrett	Mindi Richardson	Shelly Quimby	Kelly Thomsen
Dave Johns	Matt Roberts	Bonnie Gnggs	Bonnie Gnggs	Heath Loftin	Dave Johns	Matt Roberts	Rickey Rackley	Ryan Thomsen
Rodney Johnson	Jody Robertson	Michael Guinn	Michael Guinn	Richard Loftin	Rodney Johnson	Jody Robertson	Gary Ragsdale	Tori Tiffie
Tommy Johnson	Martin Robertson II	Penny Guy	Penny Guy	Dorothea Logan	Tommy Johnson	Martin Robertson II	Loren Raley	Cathy Tompkins
Joseph Kennedy	Anita Robinson	Mark Hadlock	Mark Hadlock	Mark Lopez	Joseph Kennedy	Anita Robinson	Brad Ralstin	Alenie Tran
David Kerrigan	Joey Rockett	Victor Haley	Victor Haley	Mark Lord	David Kerrigan	Joey Rockett	Juan Ramirez	Teresa Tran
Melissa Keichum	Kristen Rogstad	Mark Hamilton	Mark Hamilton	Jackie Lovell Jr.	Melissa Keichum	Kristen Rogstad	Jeff Ramsdell	TJ Treese IV
Joe Kidwell	Ken Romero	Norman Hamilton	Norman Hamilton	Justin Trent	Joe Kidwell	Ken Romero	Justin Lucas	Billy Trent
Danny King	Monica Rowell	Gabe Luttrell	Gabe Luttrell	Shannon Reed	Danny King	Monica Rowell	Dan Lynch	Lucy Trotter
Melvin Kingcade	Alisha Rusher	Dan Lynch	Dan Lynch	Christopher Remmert	Melvin Kingcade	Alisha Rusher	David Lyons	Karl Troutman
Julie Kirk	Mark Russo	David Lynn	David Lynn	Melanie Renfrow	Julie Kirk	Mark Russo	Luke Lyons	Vickie Tucker
Matt Klaassen	Beverly Sampson	Stanley Major	Stanley Major	Doug Reuss	Matt Klaassen	Beverly Sampson	Jack Rhine	Mike Turner
Jennifer Knott	Larry Savage	Regan Maness	Regan Maness	Jack Rhine	Jennifer Knott	Larry Savage	Dusty Rhoads	John Uhlenhake
David Krueger	Bob Schmicker	Michael Marker	Michael Marker	Billy Upgrove	David Krueger	Bob Schmicker	Jerry Rhymes	Billy Upgrove
Pete Lane Jr.	Michael Schmidt	Tara Martin	Tara Martin	Justin Vakilzadeh	Pete Lane Jr.	Michael Schmidt	Joe Richardson	Liz Valerio
Jeff Lasater	Dave Schoonmaker	Lolo Martinez	Lolo Martinez	Marco Vignali	Jeff Lasater	Dave Schoonmaker	Walter Richter	Aaron Vrbenc
Al Lavenue	Jennifer Scott	Rogelio Martinez	Rogelio Martinez	Lee Arnold	Al Lavenue	Jennifer Scott	Anji Riddle	David Alha
Joshua Lawson	Kim Scott	Jaime Maxwell	Jaime Maxwell	Matt Atkins	Joshua Lawson	Kim Scott	Renee Riebe	Matt Atkins
Kathy Leaseau	Kily Seaman	Tina Riggs	Tina Riggs	Melissa Atkinson	Kathy Leaseau	Kily Seaman	Tina Riggs	Melissa Atkinson
Dustin Lenhart	Geoff Beaulieu	Debbie Risinger	Debbie Risinger	Jeffrey Atteberry	Dustin Lenhart	Geoff Beaulieu	Debbie Ritter	Jeffrey Atteberry
Kerry Letoumeau	Keith Shahan	John McCarney	John McCarney	Ryan Atwell	Kerry Letoumeau	Keith Shahan	Fred Wanker	Ryan Atwell
Nick Little	Clay Shamblin				Nick Little	Clay Shamblin		

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Daniel Abeyta Jr.
Diana Acker
James Adams
John Adams
Julius Adams
Robert Adams
Tony Adams
Ronald Addison
Lance Addison
Christa Adkins
Barry Tarman
Joseph Tarver
Ray Taylor
Jon Terrell
Gerald Thomas
Randall Thomas
Renee Thomas
Robert Thompson
Kelly Thomsen
Ryan Thomsen
Tori Tiffie
Cathy Tompkins
Alenie Tran
Teresa Tran
TJ Treese IV
Billy Trent
Lucy Trotter
Karl Troutman
Vickie Tucker
Mike Turner
John Uhlenhake
Billy Upgrove
Justin Vakilzadeh
Liz Valerio
Marco Vignali
Aaron Vrbenc
Jud Walker
Jim Wallers
Desiree Walton
Fred Wanker

Rebecca Avant	Vicki Bumpas	Vernon Crumm III	Mary Filippo	Todd Gum	Randy Hooper	Brad Knight	James Maynard	Tim Napier
Brian Bailey	Rodney Burgess	Joe Cruz III	Brad Finley	Jim Gumm	Alfred Hooper Jr.	Jonathan Knight	Andrea Mays	Rusty Nash
Leigh Ann Bailey	Eddie Burk	Joshua Crystal	Donald Fisher	Rodney Gumber	Drew Hopkins	Andrew Koek	John-Paul Mays	James Neal Jr.
Donald Bain	Steve Burnett	Charlotte Cullifer	Doyle Fisher	Scott Gunwall	George Kohlhofer III	George Kohlhofer III	Vikki McBride	Scott Nease
Kyle Baker	Abiel Burnato	Larry Cunningham	Jeff Fisher	Cecil Gutierrez	Jennifer Kraszewski	Jennifer Kraszewski	Vicki McCabe	Tommy Neathery
Melvin Baldridge	Phillip Bush	Ronnie Cunningham	Marc Fleischer	Roberto Gutierrez	Rusty Kreizenbeck	Rusty Kreizenbeck	Katrina McCaslin	Donna Neel
Mills Bale	Ronnie Bynum	Walter Cunningham	Adam Flores	Adam Flores	Kim Kremer	Kim Kremer	Dax McCauley	Lisa Nelson
Jason Ball	Gavan Byrd	Arthur Curry	Lendel Floumoy	John Gwynn	Kris Kuehn	Kris Kuehn	Chris McClaine	Jerry Nevels Jr.
Scott Barks	Skye Callantine	Billy Curry	Meara Foreman	Patty Haffey	Linda Kurtz	Tim J. House	Mike McClellan	Jerry Nevels Sr.
Michael Baranski	Rick Campbell	Jake Curry	Sherman Formhals	Curtis Hagen	Tim M. House	Brian Howard	Jackie McComas	Jerrold Newberry
Gary Barnard	Deric Canary	David Outright	Dionne Forrest	Talmadge Hager	Anthony Laffery	Anthony Laffery	Thomas McComas	Kana Newman
Rick Barnes	Elmer Canary	Irene Da Rocha	Darcie Foster	Lea Hain	Bill Laffery	Bill Laffery	Meri McCorkle	Roger Newsome
Mark Barringer	Michelle Cantrell	Mandy Daigle	Jason Fournier	Ronald Halbert	Paul Laffery	Paul Laffery	Dave McCormick	Bernard Nguyen
Shawn Barron	Steve Cantrell	Bo Daniel	Steve Fredendall	Donny Hale	Jennie Lambert	Jennie Lambert	Johnny McCoy	Robert Navez
Karen Bartley	Bryan Carey	Christy Dare	John Freeman	Garrett Hale	Sidney Lane	Sidney Lane	Rocky McCoy	Stacie Nicholson
Scott Barton	Patrick Carey	Fred Daugherty	Scott Freeman	Paul Hale	Sonny Htoon	Sonny Htoon	Steve McCracken	Sid Niles
Bob Bary	Silas Carnes	Donald Davey	Ray French	Barb Hall	Paul Hudgins	Paul Hudgins	Forrest McCurtain	Justin Ninrod
Diana Bast	B.J. Carney	Bryce Davis	Ricky French	Bridgette Hall	Ann Hudson	Ann Hudson	Gene McCutcheon	Kelly Nix
Beverly Battisti	Dennis Carpenter	Emily Davis	Victor Frias	Don Hall	Jeff Huelskamp	Jeff Huelskamp	Casey McDonough	Curtis Nixon Jr.
Bob Baxendale	Mendy Carpenter	Jacob Davis	Bret Frie	Jennifer Hall	Janet Huffman	Janet Huffman	Vanessa McDougal	Kenneth Nolan
Dustin Baxter	Shannon Carrion	Steven Davis	Scott Friedman	Lynn Hall	Christine Hughes	Christine Hughes	Will Lawler	Rodney O'Brien
Lyndal Beasley	Cathy Carter	Ricky Daw	Mike Friend	Marcus Hall	Larry Hughes	Larry Hughes	Ronnie Lawrence	Adam Olivares Jr.
Thomas Beaty	Kyle Carter	Scott Delaney	Rodney Friend	Mike Hall	Rodney Hughes	Rodney Hughes	Terry McGraw	Michele Oliver
Joe Beaudoin	Zulema Casas	Marin Delao	Rachael Fogate	Joe Halstead	Zachary Humphrey	Zachary Humphrey	Gina Lawson	John O'Neal
John Beckwith	Cassie Casto	Jeremy Denton	Deedra Fullbright	Riley Hamar	Robert Hurst	Robert Hurst	Sarah Laymon	Dara Oney
Keith Bell	LuAnn Chance	Alissa Devaughn	Toby Fullbright	Dawn Hamilton	Amy Hutchinson	Amy Hutchinson	Robin Layne	Cheryl Ormston
William Bennett	Darrel Chandler	Aletha Dewbre-King	Kevin Furr	Wheeler Haunmit	Joe Iile	Joe Iile	Jeremy Lee	Charles Osborn
Robert Bien Jr.	Donald Chaney	Hank DeWitt	Dennis Gagliardi	Buddy Harbison	Suzie Ingram	Suzie Ingram	Larry Lee	Shane Osborn
Kerry Bird	Brian Chapman	Brent Dixon	Michael Gallo	Rusty Hardin	Betsy Ireson	Betsy Ireson	Keith Lehman	Billy Osendott
Cornelius Birmingham	Chad Chapman	Monty Dixon	Beau Galloway	Cleab Gamble	William Ireson	William Ireson	Gaylon Lemley	Bryan Ott
Milton Bishop	Monty Dixon	Darrell Dolens	Alma Garcia	Lori Garcia	Rodrick Island	Rodrick Island	Brad Lemon	Kary Ott
Andrew Black	Billy Childers	Pete Dominguez	Carl Donevin	Kelli Donovan	Bobby Ison	Bobby Ison	Joe Lemon	Katie Overton
Jackie Black	Anita Chin	Nikki Church Lemon	Kathy Coffey	Tyler Doolen	Johnny Ison	Johnny Ison	James Lenhart	Tony Padgett
Kenneth Blackburn	Charles Clark	Charles Clark	Barney Dosier	Liz Gerhard	Nathan Harless	Nathan Harless	Shannon Lenhart	Joe Paetzold
Thomas Blackburn	Linda Clark	Charles Clark	Amie Gibbons	Phyllis Harris	Shauna Harmon	Shauna Harmon	Mary Lesley	Wray Paine
Blake Blackwell	Rip Clary	James Clay	Stephen DuBois	Dane Dunegan	Keneth Hartfield	Keneth Hartfield	John Paul Leslie	Bill Parker
Jon Blaker	Dane Clayton	Jason Clayton	Josh Gibson	Vincent Gibson	Brent Johnson	Brent Johnson	Dustin Lewis	Matthew Parker
Richard Blankenship	Elizabeth Clem	Jack Clement Jr.	John Dunlap Jr.	Ronald Dunlap Jr.	Bruce Johnson	Bruce Johnson	Al Leyva	Michael Parker
Alisa Blevins	Jack Collette	Bryan Clevinger	Dustin Durkee	Houston Eagleston	Danna Johnson	Danna Johnson	Martha Lezama	Toni Parks-Payne
Ron Bliss	Kevin Collins	Paul Coffey	Joe Earley	Anthony Earnest	Greg Johnson	Greg Johnson	Wayne Light Jr.	Trisha Pate
Connie Bloss	Tiffany Collins	Jackie Cole	Jackie Cole	Mike Edwards	Mark Johnson	Mark Johnson	Terri Lindsey	Hoot Patterson
Dot Blythe	Christian Combs	J.C. Coleman	J.C. Coleman	William Edwards	Steve Johnson	Steve Johnson	Dan Lopata	Kevin Patterson
Nick Boeckman	Douglas Combs	Robert Coleman	Robert Coleman	Travis Egner	Kevin Johnston	Kevin Johnston	Becky Lorton	Kenneth Payne
Leonard Boeckman Jr.	Gary Compton	Michele Compton	Michele Compton	Bill Connard	Bob Henderson	Bob Henderson	Bruce Melton	Deborah Payne-
Charlie Boggs	Bill Connard	Kay Elrod	Alan Elswick	Ricky Endicott	Caroline Goodall	Caroline Goodall	Oscar Mendoza	Sherwood
Timothy Bohannon	Phyllis Copley	Jim Estep	Gant Estes	David Eudey	Colby Evans	Colby Evans	Saxon Mesa	Nicky Peacock
Raymond Bohnet	Curtis Corcoran	David Eudey	Colby Evans	Ricky Evans	Stacey Evans	Stacey Evans	Paul Messer	Adriel Pearce
Corey Bolding	Glenn Cornette	Steve Coshaw	Geron Cottam	Dennis Cotton	Tim Cottrell	Tim Cottrell	Jeffrey Meyers	Billy Pennington Jr.
Kenzi Bond	Steve Coshaw	Phyllis Copley	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Steven Michael	Sabrina Pepper
Ronnie Bonnett	Phyllis Copley	Curtis Corcoran	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Clay Mickliff	Tom Pepper
Adam Bos	Glenn Cornette	Steve Coshaw	Geron Cottam	Dennis Cotton	Tim Cottrell	Tim Cottrell	Casey Miller	Charles Perez
Ryan Bose	Steve Coshaw	Phyllis Copley	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Cathy Miller	Philip Permenter
Jason Bossard	Phyllis Copley	Curtis Corcoran	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Daryl Miller	Brooks Perry
Amer Bostic	Curtis Corcoran	Glenn Cornette	Steve Coshaw	Geron Cottam	Dennis Cotton	Dennis Cotton	Jeff Miller	Gena Perry
Tim Bostick	Steve Coshaw	Phyllis Copley	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Kelli Miller	Jody Perry
Mark Bottrell	Phyllis Copley	Curtis Corcoran	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Mark Miller	Mike Perry
Joe Bradford	Curtis Corcoran	Glenn Cornette	Steve Coshaw	Geron Cottam	Dennis Cotton	Dennis Cotton	Eliagab Mills	Denward Peters
Everett Bradford	Steve Coshaw	Phyllis Copley	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Thomas Mills	Aaron Peterson
Ryan Bradley	Phyllis Copley	Curtis Corcoran	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Maya Mims	Joe Peterson
LeRoy Bradt	Curtis Corcoran	Glenn Cornette	Steve Coshaw	Geron Cottam	Dennis Cotton	Dennis Cotton	Kyle Minaryard	Donald Petzold Jr.
Kenny Bragg	Steve Coshaw	Phyllis Copley	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Greg Mitchum	Kevin Pfister
Debra Branham	Phyllis Copley	Curtis Corcoran	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Jeff Mobley	Greg Pichler
Gail Branham	Curtis Corcoran	Glenn Cornette	Steve Coshaw	Geron Cottam	Dennis Cotton	Dennis Cotton	Leisa Monk	Michael Pickens
William Branham	Steve Coshaw	Phyllis Copley	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Frankie Montez	Susan Pickens
Del Brazael	Phyllis Copley	Curtis Corcoran	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Agnes Moore	Steve Pierce
Chris Brennan	Curtis Corcoran	Glenn Cornette	Steve Coshaw	Geron Cottam	Dennis Cotton	Dennis Cotton	Jim Moore	Billy Pillars
Randel Briggs	Steve Coshaw	Phyllis Copley	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Michael Moore	Josh Pitts
Jordan Brim	Phyllis Copley	Curtis Corcoran	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Sherrie Moore	Kyle Pily
Candy Brinegar	Curtis Corcoran	Glenn Cornette	Steve Coshaw	Geron Cottam	Dennis Cotton	Dennis Cotton	Teresa Moore	Steve Poe Jr.
Dennis Brock	Steve Coshaw	Phyllis Copley	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Samuel Morehead Jr.	Julie Poore
Brent Bromlow	Phyllis Copley	Curtis Corcoran	William Branham	Del Brazael	Chris Brennan	Chris Brennan	David Morehouse	Harold Porter
Wilfred Broussard	Curtis Corcoran	Glenn Cornette	Steve Coshaw	Geron Cottam	Dennis Cotton	Dennis Cotton	Jose Moreno III	Johnny Porter
Donna Brown	Steve Coshaw	Phyllis Copley	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Phil Moser	Leon Potter
Keith Brown	Phyllis Copley	Curtis Corcoran	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Bill Mottesheard	Thomas Potter
Richard Brown	Curtis Corcoran	Glenn Cornette	Steve Coshaw	Geron Cottam	Dennis Cotton	Dennis Cotton	Doug Mullins	Jared Pounds
Bryant Brown Jr.	Steve Coshaw	Phyllis Copley	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Jaime Munoz	Cara Pourtoikan
Billy Brumley	Phyllis Copley	Curtis Corcoran	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Don Muret	Lynn Powell
Bill Bruner	Curtis Corcoran	Glenn Cornette	Steve Coshaw	Geron Cottam	Dennis Cotton	Dennis Cotton	Joshua Maxey	Ryan Prater
Kathy Buckley	Steve Coshaw	Phyllis Copley	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Maya Maximova	Reco Preece
Michael Buckner	Phyllis Copley	Curtis Corcoran	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Jeff Maxwell	Adam Price
Nichole Buersmeyer	Curtis Corcoran	Glenn Cornette	Steve Coshaw	Geron Cottam	Dennis Cotton	Dennis Cotton	Mike May	Bob Price
	Phyllis Copley	Curtis Corcoran	William Branham	Del Brazael	Chris Brennan	Chris Brennan	Samuel May Jr.	Mitch Price IV

John Prichard	Carl Sargent	Jack Stockton	Kathy Watson	James Allen	Roger Barnes	Randy Blood	Todd Bules	Bobby Carroll Jr.
Jennifer Prince	Jay Savill	Brandon Strack	Luke Watson	Jamie Allen	Timothy Barnett	Emmett Blythe	Clifton Bullard	Chris Carson
Martin Province	Brandon Scheffler	Sam Straley	Vickye Watson	Jason Allen	Keith Barrett	Jason Bohard	Niki Burch	Audie Carter
Bobby Putman	Rob Schindler	Dan Stricker	Delanna Watts	Joshua Allen	Kirk Barrilleaux	Doug Bohlen	Clinton Burditt	James Carter
Randy Queen	Doug Schmidt	Lola Strickland	John Weaver	Randall Allen	Cecelia Barrington	Richard Bolding	Jay Burford	Staci Carter
Terry Quentrell	Mason Schmidt	Shay Stricklin	Angie Webb	Deek Allison	Allison Albert	Marvin Bond	Roger Burford	Francis Carrullo Jr.
Jack Quisenberry II	Clark Schneberger	Callie Stuckey	Ginny Webb	Kristopher Allison	Jonathan Bartlett	Brandi Bonner	Darrel Burghardt	Alex Castas
Ann Radcliff	Randall Schultz	Dave Stumbo	James Webb	Junmy Allred	Joshua Barton	Daniel Borowski	Justin Burgin	Charles Cass
Jeff Raines	Cynthia Schweigen	Tom Sudchai	Thomas Webb	Kenneth Allens	Brandon Bashaw	Jason Boswell	Stephen Burgin	Bernardino
Weldon Rainey	Greg Schwerdtfeger	Travis Sullivan	Lisa Webb Johnson	Brandon Allums	Jimmy Bashaw	Johnathan Boswell	John Burkhouse Jr.	Castandeta Jr.
Larry Raleigh	Corey Scott	Scott Sullivan	Shae Weddle	Richard Allums	Adam Basquez	Thomas Botles Jr.	Jake Burnett	Charles Castelli
Luis Ramirez	Emily Scott	Kelly Sunderbruch	Jeff Weides	Julio Almanza	Jason Bass	John Bottrell II	Jim Burnett	Jose Castelo
Kyle Range	Jim Scott	Todd Swartzbaugh	Keith Wells	Al Alonzo	Michael Bass	Brian Bounds	Aaron Burns	Jefferson Castie
Keith Rasmussen	Kathy Scott	Anthony Sweeney	Lee Wesoot	Billy Alven	Warren Bass	Calvin Bounds	Andrea Burns	Andrea Castillo
Billy Radliff	Leah Seaman	Charles Switzer	Krista Whiddon	Joe Aly	Douglas Baughman	Barbara Bowersox	Burton Burns	Jose Castillo
Jennifer Ratliff	Leah Seaman	Annarda Talnich	Tyson Whisman	James Amelung	Tammy Baxter	Deven Bowles	Deven Burns	Aaron Castio
Tory Ratliff	Jennifer Scho	Jim Tample	Kyle White	Bob Anyx	Jerald Bayless	Donald Bowman	Lynn Burns	Brandon Cates
Peter Rauscher	Larry Segar	Philip Tanner	Larry White	Rodney Ancell	Nicole Baylor	Drew Boyer	Robert Burns	Jared Cavanaugh
Cody Ray	Steve Seliquini	Mike Tarpley	Mallorie White	Thomas Anderson	Thomas Beall	Gene Boyer	Valerie Burns	Scott Caver
David Ray	Ivan Semien	Brian Tatro	Dan Whitmarsh	Clifton Anderson	Jason Bear	Ernie Bozarth	Charles Burnsworth	Gregory Cavness
Donna Ray	Perry Settles	Fred Taylor	Valerie Wible	Gary Anderson	Larry Beard	Phillip Bradford III	Donny Burnsworth	Cassie Cayner
John Ray	Thomas Seyler	Georold Taylor	Charles Wilburn	Otis Anderson	Tim Beard	Justin Bradley	Richard Burrhus	Rosa Chacon
Lonnice Ray	Gail Shackelford	Jody Taylor	Clay Wilcox	Shelby Anderson	Johnny Beasley	John Bradshaw	Phil Burrow	John Chadwick
Vickie Ray	Jeff Shafer	Stephen Taylor	Dale Wildman	Shelby Andrew	Jesse Beason	Tod Brakebill	Val Jo Burrows	Tim Chaloupek
Caleb Redd	Tommy Shaffer	Eric Tennant	Brooke Wiley	Melanie Andrews	David Beatty	Kirk Braley	Joseph Burton	Jack Chambers
Gavin Reed	Lisa Shaffer-Moore	Amarda Terry	Mark Wiley II	Charles T. Angle	Bucky Beaver	William Brandt	William Busby	Harvey Chambliss
Kenneth Reed	Arcio Sharp	Leslie Terry	Lisa Wilkinson	Charles D. Angle	Tiffany Beaver	Leslie Branham	Daniel Busber	Tory Chambliss
Melissa Reed	John Sharp	Steve Tharp	Dallas Williams	Greg Archer	Brian Beavers	Mark Brannon	Dustin Bushnell	Robert Channel
Nathan Reed	Stan Shaw	Joe Thomas	David Williams	Mike Armstrong	Cory Becher	Mathew Branson	Casey Buster	David Chapman
Pat Reed	Donald Shelley	Lawrence Thomas	Mereth Williams	Michael Arndt	Ben Becker	James Branton	Adrian Butler	Dennis Chapman
Steve Reed	Marvin Shepherd	Val Thomas	Quentin Arndt	Quentin Arndt	Terr Becker	Zora Braun	Bill Buzan	Paul Charles
Brian Reeder	John Shifflett	Cameron Thompson	Jordan Arney	Jordan Arney	Steven Beckett	Erika Braver	Michael Buzan Jr.	Roger Chatham
Lorrie Renfro	Debra Shingleton	Debra Thompson	Aaron Arnold	Aaron Arnold	Jim Bedford	Chris Brawley	Jerrold Byrd	Faaria Chaudhry
Phillip Renner	Tammy Shingleton	Rick Thompson	Fawn Arnold	Fawn Arnold	Clint Beedy	James Bray	Eric Bynum	David Chavarria
R.J. Retzer	Taylor Shinn	Willie Thompson	Howard Arnold	Howard Arnold	Jed Beegle Jr.	David Bray Jr.	Tom A. Bynum	Oscar Chavez
Nate Reutotzar	Mike Short	Hack Willis	Zachary Arnold	Zachary Arnold	Austin Beeler	Michael Brenizer	Tom W. Bynum	Kathy Cheesman
Jason Reynolds	John Shreve	Ronnie Willis	Juan Arriazola Jr.	Juan Arriazola Jr.	David Beers	Robert Brevelle	Chester Byrd	James Cheslin
Jeffery Rhoades	Billy Trimmons	Kent Willoughby	Dave Arrington	Dave Arrington	Scott Besson	Shawn Brewer	Eric Byrd	Dennis Childress
Stewart Rhoades	Lee Shreves	Jeremy Willyard	Justin Ash	Justin Ash	Steve Reeson	Bradie Brewton	Korey Byrd	Henry Childress
Jerad Rhodes	Tara Shumate-Lee	Kelly Torri	Thad Ashcraft	Thad Ashcraft	Danny Beets	H. Briant	Sam Byrd	Michael Childress
Mike Rice	Derrick Sier	Michelle Wilson	Kevin Ashley	Kevin Ashley	Nicholas Begaye	Jamie Bridges	Scott Bynum	Richard Childress
Ray Rice	Bob Simmons	Brian Wines	Tim Ashley	Tim Ashley	Jeff Behmyer	Keith Briggs	Eric Cabell	Stephanie Choate
Chad Richardson	Brian Simmons	Matej Triska	Arny Askew	Arny Askew	Bo Belendam	Melvin Bright Jr.	Jeff Cable	Rodney Christian
Joni Richardson	Steve Simms	Scott Truesdale	Micah Assulin	Micah Assulin	Robyn Belew	Greg Brillhart	Juan Cabrera	Liz Christianan
William Richardson	Justin Simonton	Vernetta Tubbs	Michael Atkinson	Michael Atkinson	Paige Benedict	Thomas Brinegar	Timothy Cagle	John Christmas Jr.
Ralph Riffle	Cami Sims	Marvin Turner	Roger Averitt	Roger Averitt	Cheryl Bennett	Wesley Broggin	Stephanie Cahill	Twila Christy
Johndetta Riley	Billy Sims Jr.	Matt Turner	David Avery	David Avery	Dustin Bennett	Chad Bromley	Natasha Gaines	Brandon Church
Johnney Riley	Susan Tuter	Susan Tuter	Jose Avila Jr.	Jose Avila Jr.	Garrett Benton	Billy Bromlow	David Calahan	Kerry Clapp
Steven Riley	Gloria Tyree	Gloria Tyree	Scott Ayers	Scott Ayers	Jacque Bergman	Ronald Bromlow	Jerry Caldwell	Suzanne Clapper
Brandon Ripley	Ralph Skinner Jr.	Kenna Ulderich	Ed Back	Ed Back	John Bergman	Ed Brooks	Frank Calhoun	Brandon Clark
AJ Risner	Malcom Sloane	Sharon Ulmer	Misty Baeza	Misty Baeza	Danny Berkeley II	Jeffrey Brooks	Rodney Calhoun	Cody Clark
Nakita Rizzo	James Smalts	Traci Underkoffler	Tim Bagby	Tim Bagby	Sharon Berkley	Timothy Broom	Rickie Callender III	David Clark
Robert Robicheaux	Eric Smith	Jason Updegraff	Allen Bagley	Allen Bagley	Sherry Bernstein	Vernon Broomfield	Jason Cameron	Dustin Clark
Ben Robinson	John Smith	Dana Vaden	Robert Bagley	Robert Bagley	Eric Bess	Rob Brott	Johnnie Campbell	James Clark
John Robinson	Jonathan Smith	Joseph Valerio II	Michael Bagley	Michael Bagley	Larry Beswick	Russell Broussard Jr.	Justin Campbell	Leon Clark
Rusty Robinson	Lindsey Smith	Clint Vallandingham	Frederick Bailey	Frederick Bailey	James Bethell	Guy Brower	Karen Campbell	Stacey Clark
Randy Rodrigue	Roy Smith	Banner Vanderpool	Ronald Bailey	Ronald Bailey	Tom Bettis	Aaron Brown	Kenny Campbell	Steve Clark
Pedro Rodriguez	Scott Smith	Cindy Vandeverner	Charles Baker	Charles Baker	Cody Brown	Daniel Brown	Kim Campbell	William Clark
Brad Rogers	Stephen Smith	Jackie Vaughan	Buich Baird	Buich Baird	Daniel Brown	Donald Brown	Shanna Campbell	Jason Claurch
Cliff Rogers	Tim Smith	Ryan Veirs	Charles Baker	Charles Baker	Donald Brown	Jay Brown	Billy Campbell III	Heather Clay
John Rogers	Deby Snodgrass	Suzanne Victoria	Dennis Baker	Dennis Baker	Jay Brown	Jerry Brown	Billy Campbell Jr.	Quinten Clay
Karen Roller	Donna Snyder	Lupe Villarreal Jr.	Sitaraman	Sitaraman	J.P. Brown	J.P. Brown	Joseph Canaday	Brad Claypool
Carlos Roque	Ronald Snyder Jr.	Tammie Voelker	Balakrishnan	Balakrishnan	Kevin Brown	Kevin Brown	John Canary	Jesse Clayton
Chuck Rose	Mantuel Soriano Jr.	Lindsey Von Tungetn	Boomi	Boomi	Leon Brown	Leon Brown	Cesar Canta	Cathi Clements
Dayton Rose	David Southern	Lori Vreeland	Balasubramanian	Balasubramanian	Natascha Brown	Natascha Brown	Noel Cantu	Eric Clements
Kristin Rose	Myron Sowards	Nancy Wade	Leonardo Baldonado Jr.	Leonardo Baldonado Jr.	T. Brown	T. Brown	James Cantwell	Jeff Clements
Anne Ross	Sheltee Spencer	Carol Wagner	Jason Baldrige	Jason Baldrige	Pam Billingsley	Pam Billingsley	Edgar Cardenas	Michael Clevenger
Mike Rossiter	James Spiller	Kenneth Wagoner	Daryl Baldwin	Daryl Baldwin	Foster Bingaman	Foster Bingaman	Steven Carder	Ronald Clift
Ed Rothman	Keith Spitzberger	Sandra Wagoner	Christa Ball	Christa Ball	Matthew Birch	Matthew Birch	John Cargle	Jimmy Clowers
Lloyd Rubottom	Nelson Spradlin	Jay Walker	Hinojosa	Hinojosa	Don Bishop	Don Bishop	Timothy Brummage	Lindy Cochran
Gary Russell	Larry Stacy	Benny Wallace	Aniceto Aguinaga	Aniceto Aguinaga	Ryan Bishop	Ryan Bishop	Alan Brunson	Robert Cochran
George Russell	Tommy Stanley	Charles Wallen	Chaudhry Ahmed	Chaudhry Ahmed	Bryant Black	Bryant Black	Greg Bruton	Timothy Cockerham II
Jim Russell	Briana Suedman	Richard Walls	James Ainsworth	James Ainsworth	Jeremy Black	Jeremy Black	Cheryl Bryan	Brent Cockerell
John Ryza	Trza Steiner	Leonard Walters	Michael Ainsworth	Michael Ainsworth	Jeremy T. Black	Jeremy T. Black	J.D. Bryant	Bradley Carr
Scott Sachs	Marshall Stephens	John Walls	Doyal Akers	Doyal Akers	David Black Jr.	David Black Jr.	Ron Bryant	Lauren Coko
David Salinas	Sheila Stepp	Seah Ward	Ricky Alcom	Ricky Alcom	Willis Blaker III	Willis Blaker III	Marria Brydon	Ryan Coe
Clinton Salyers	Terry Steward	Justin Wardrop	Anthony Aldridge	Anthony Aldridge	Brandon Buckaloo	Brandon Buckaloo	Norman Carrick	Stanley Coger
Rachel Samara	Robert Sticker II	Steve Warnuck	Kris Aldredge	Kris Aldredge	Chad Buckhalter	Chad Buckhalter	David Carroll	Byron Cole
Brett Sample	Crystal Stidham	Brian Wasinger	Laurel Alexander	Laurel Alexander	Phillip Blankenship	Phillip Blankenship	Debi Carroll	Randy Cole
Gary Sanders	Jason Stidham	Henry Watson	Daniel Alford	Daniel Alford	Emily Blaschke	Emily Blaschke	Dewey Carroll	Sarah Cole
Jason Sarakatsannis	Justin Sunson	Karen Stock	Kenny Alford	Kenny Alford	Joel Bledsoe	Joel Bledsoe	Gregory Buda Jr.	Christopher Colebank
			Robert Alldredge	Robert Alldredge	Jimmy Blevins	Jimmy Blevins	James Carroll	Virgil Coleman
					David Blood	David Blood	Stephan Carroll	Davy Collins

Katie Collins	Ray Cunningham	Zachary Donovan	Leann Evers	Stephen Fuhs	Billy Goodnight	Anthony Harkness	ErinLeigh Hill	J-Michael Ice
Deanna Combs	Robert Cunningham	Donald Dotson	Ronnie Ezemack	Evan Fuqua Jr.	Justin Goodson	James Harman	James Hill	Dennis Idlett
Joshua Combs	Robert Cunningham II	Stephanie Doy	Anthony Faison	Christine Furbee	Elijah Gordon	Rob Harmon II	Joy Hill	Elbert Idlett
Vernon Combs	Rance Cupp	Dawn Douglas	John Farnsworth	Carol Gaddis	Carol Gordon	Joshua Hamed	Steve Hill	Justin Idlett
Jason Conaway	Douglas Czako	Greg Douglas	Richard Farnsworth	Maria Gadsden	Nathan Gore	John Hamsberger	Suzanne Hill	Loyd Idlett
Greg Condray	Aaron Daharsh	John Douglas	Ricky Farnsworth	Frank Gagliardi	Lorie Goss	Michael Harper	Michael Hillon	Chad Imani
Ronald Conifer	Carrie Daigle	Johnny Dowdy	Andrew Farris	Sarah Gainer	John Goss	Cody Harrel	Robert Hines	Stanley Ingle
Jeff Conley	Charles Daily	John Downing	George Farris	Matthew Gaines	Lindsay Gowan	John Harrington Jr.	Clyde Hinson	Donavan Ingram
Chrissy Conner	Laurie Dameron	Timothy Downs	Marcie Farris	Morgan Gallimore	Bryan Harris	Bryan Harris	Mark Hladky	Jennifer Ingram
Jeremy Conner	Michael Dameron	Kristin Drain	Shyla Fast	Cecil Gamble	Clifford Harris	Clifford Harris	Chad Hledik	Pete Irby
Dusty Conway	Bracey Dangerfield	Tammy Dresser	Steven Feisal	Robert A. Gamble	Donn Goss	Jill Harris	Justin Hobbs	Jeff Iven
Andy Corners	David Dani	Wayne Drew	Bryan Ferguson	Robert J. Gamble	Bill Gravitt	Kristina Harris	William Hodge	Robert Izell
Blayne Cook	Kassie Danker	Raul Duenas	Keith Ferguson	Joshua Gant	Ron Gray	Mike Harris	Jake Hodge	Sherry Izell
Jim Cook	David Danley	Alfonso Duenez	Tessie Ferguson	Gerardo Garcia	Benjamin Green	Robert Harris	Jimmy Hodges	Christopher Jacks
Justin Cook	Alvin Danley Jr.	Jorge Duenez	William Ferrebee	Homer Garcia Jr.	Gabe Green	Terry Harris	Joseph Hodges	Joe Jackson
Melissa Cook	Joseph Darr	Jimmy Duncan	Kevin Fields	Junior Garcia Jr.	Allan Greenawalt	Beth Harrison	Justin Hodges	Lindsay Jackson
Jacob Cooper	Beverly Dart	Wade Duncan	Perry Fields III	Martin Garcia Sr.	Justin Greenfield	Patty Hoecker	Loyd Harrison	Marianne Jackson
Larry Cooper	Jeffrie Davidson	Bryan Dunlap	Jose Fierros	Oscar Garcia	Dylan Grey	Eric Hoehne	William Harrison	Eric Holman
Linda Cooper	Baldemar Davila	Dustin Dunlap	Michael Figard	Johnny Garcia	Samuel Harroff	Chad Hoffman	Samuel Harroff	Pamela Jackson
Justin Coots	Bernardo Davila	Regina Dunlap	Miguel Figueroa	Chris Gardner	Darrel Hart	Henry Hoffman	Darrel Hart	Randall Jackson
Scott Copeland	Betsy Davis	Cotton Dunley	Tommy Fillman	Jeff Gardner	Don Hart	Lisa Hoffman	Don Hart	Jana Jacobs
James Copeley	Bryan Davis	Curtis Dunn Jr.	Julia Finch	Reecie Gardner	Robert Hart	Robert Hogle	Robert Hart	Johnnie Jacobs
Thomas Corbett	Chad Davis	Larry Durant	Thomas Finch	George Garfield	Bradley Holland	Bradley Holland	Bradley Holland	Kristi Jacobs
Brad Corbin	Dustin Davis	Paul Duren	Brent Finley	Bonnie Garner	James Holland	James Holland	Kevin Hartl	Troy Jacobs
Ricky Cordova	Gary Davis	Jim Durst	Curtis Finley	Brandon Garrett	Lane Grimes III	Tom Holland	Roger Hartley	Javey Jamison
Jade Corkery	Jennifer Davis	Dustin Dye	Sieve Fisbeck	Lisa Garrett	Bobby Harvey	Michael Holloway	Bobby Harvey	Lance Jamison
Jeff Cornelius	Joseph Davis	Robert Earnest	Thomas Fish	Mark Garrett	Steven Harvey	Thomas Holliman	Steven Harvey	Todd Jamison
Justin Cornell	Kathy Davis	Michelle Eaton	Armando Garza	Armando Garza	Don Harville	Michelle Hollis	Don Harville	Kyle Janzen
Steve Cornett	Megan Davis	Tammy Eaton	Jerry Fisher	Javier Garza	Frankie Grogan	Mike Hollis	Thomas Hass	Christopher Janzen
Manuel Coronado	Michael Davis	Robin Ebarb	John Fisher	Joel Garza Jr.	James Grogg	Bradley Holman	Timmy Hass	Rachel Jarrett
Preston Corp	Michael Davis Sr.	Eric Ebbe	Michael Fite	Raul Garzes	Michael Grothe	William Holman Jr.	Jamie Havens	Anthony Jeansonne
Diego Cortez	Robert Davis	Melissa Eckhardt	Chris Flanagan	Rafael Garzes	Jody Grunder	Blair Holmboe	Chad Hawkins	Travis Jenkins
Mario Cortez	Robert Davis Jr.	Michael Eddins	John Gasaway	Doug Gaston	Rafael Guerra	Eric Jenkinson	Charles Hawkins Jr.	Chris Jenkinson
Janice Cory	Rodger Davis	Craig Eddy	Matt Fleischer	Scott Gaston	Victor Guillory	Terry Jennings	Darcy Hawkins	Tony Jennings
Bob Costello	Ron Davis	Jonathan Eddy	Brenda Flesher	Ricky Gadin	Brandon Guinn	Michael Holson	Lucas Hayden	Jon Jernigan
Bobby Costello	Sean Davis	Lisa Edinger	David Flores	Brian Gaunt	Donald Gunnoe	Charles Holt	Carroll Hayes	Christopher Jimenez
Cody Costello	Dustin Dawson	Robert Edwards	Jennie Flores III	Jeff Gunter	Jeff Gunter	Larry Holt	Danny Hayes	David Jrousek
Larry Costello	Kenny Dawson	Johnny Egnor Jr.	Jesse Flores Jr.	John Gutenberg	Galen Gustavus	Dustin Holmesley	Eric Hayes	Alex Johnson
Stoney Costello	Robbie Day	Johnny Egnor Sr.	Shawn Gayle	Henry Gutierrez Jr.	John Gutenberg	Michael	Christopher Hayward	Corey Johnson
William Coston	Jessie De Jong	Craig Elder	Jeremy Gearhart	Ivan Guzman	Henry Gutierrez Jr.	Robert Hayward	Patrick Healy	Dan Johnson
Ricky Cotton	Bryan Dean	Jammie Elder	Bradley Gentzler	Ricardo Guzman	Ivan Guzman	Patrick Healy	Teresa Hearn	Dana Johnson
Crystal Coutrell	Greg Dean	Jeff Elder	Anne George	Darryl Haas	Ricardo Guzman	Teressa Hearn	Darryl Haas	Don Johnson
Chris Courtney	Landon Dean	Jeremy Ellard	Joshua Floyd	Eric Ghee	Scott Hackworth	Kevin Hooper	Justin Heath	Kevin Hooper
Greg Courtney	Stanley Dean	Ryan Ellefson	Richard Floyd	Allen Gibson	Scott Hackworth	David Hoover	Terry Heath Jr.	David Hoover
Larry Cowey	Thomas Decker	Thomas Elli	Terry Floyd Jr.	Bobby Gibson	Shad Haddad	Steven Hoover	Anne Heatly	Steven Hoover
Jereme Cowan	Kevin Deeds	Cody Elliott	Edward Flynn	Davin Gibson	Lance Haffner	Melissa Hoppe	Virginia Hebert	Colby Horn
Jeffery Cowger	Matthew Deel	Ebbin Elliott Jr.	Thomas Flynn Jr.	Seven Giddings	Loren Hagar	Jerry Hoskins	Amber Hedges	Jerry Hoskins
Chris Cox	Tim Deffenbaugh	James Elliott III	Gerakl Fogle	Timothy Giddings	Bob Hageron	Tim Johnson	Mark Helm	Ronnie Hoskins
Jeremy Cox	Donald DeForest Jr.	Christopher DeJarnett	Roger Foley	Jon Gillin	Wayne Haide	William Johnson	Tim Helms	Jon-Aaron House
Steven R. Cox	Michael DeJarnett	Robert Elliott Jr.	Danny Ford	Dewayne Gilkerson	Josh Halbert	Jeri Johnson	Benjamin Henderson	Debbie Houston
Steven W. Cox	Darryl Delao	Darby C. Ellis	Martha Ford	Bobby Gillette	Freddy Hale	Joy Johnston	Daniel Henderson	Seth Houston
Vince Cox	Justin Delander	James C. Ellis	Jimmy Forsyth	Anthony Gilliam	Kim Haley	Anthony Jones	George Henderson	Corey Hovis
Scott Crim	Bradley Dennis	Melanie Ellis	Steven Forsythe	Cameron Gilmer	David Hall	Bryan Jones	Nicholas Henderson	Kevin Howard
Donnie Craft	Tina Craft Grant	Daryl Dennis	Anthony Foster	Jim Gipson Jr.	Gabriel Hall	Cindy Jones	Chad Hendrick	Matt Howard
Tina Craft Grant	Dave Craig	Kelly Elswick	Clarence Foster	Paul Givens	Karen Hall	Daniel Jones	Brian Henley	Scott Howard
Dave Craig	Vincent Dermbach	Darrel Enderlin	Robert Foster	Ross Glancy	Terry Hall	Gary Jones	John Henley	Seth Howard
Denise Cramer	Mark C. Deshazo	Blake Engelman	Chris Fournier	William Glancy	Mary Henning	John Jones	Mary Henning	Jason Howe
Bud Cravey	Mark D. Deshazo	Michael England	Clayton Foutch	Ryan Glenn	Mark Henry	Kenneth Jones	Mark Henry	Kenneth Hubbard
Rebecca Crayton	Tracei Devereaux	Richard England	Julie Fox	Tristen Goans	Dan Hensley	Kyle Jones	Dan Hensley	Landon Hubbard
Jonathan Creagan	Karl Dexter	Eric Englehaupt	Howard Fox Jr.	Ron Goble	Johnny Hensley	Steven Jones	Johnny Hensley	David Huckabee
Joe Creech	Robert Dial II	Jeremy Englehaupt	Kristoffer Foy	Callie Godwin	Randy Henthorne	Travis Jones	Randy Henthorne	Cheryl Hudak
Ricky Crider	Gianni Diaz	Jon English	Alejandro Fraire	Dora Goff-Parsons	Jeremy Herman	Chad Jongeling	Jeremy Herman	Chase Huddleston
Jerry Crider II	Kim Dickerson	Richard Enoff	Andy Frame	Scott Goldsberry	Armando Hernandez	Bev Jordan	Armando Hernandez	Donnie Huffman
Scott Crim	Andrew Dickurs	Robert Epperly	Shane Frampton	David Gomez Jr.	David Hernandez	Doug Jordan	David Hernandez	Daniel Hughes
Jesse Crissup	Shaun Dickson	Seven Epps	Tina Francis	Jesse Gomez	Gordon Hernandez	Jeff Judd	Gordon Hernandez	Jarel Hughes
Steve Crocker	Jennifer DiEgidio	Ramiro Escamilla Jr.	Greg Franz	Jorge Gomez	Miguel Hernandez	Nicholas Judd	Miguel Hernandez	Justin Hughes
Jimmy Crose	Todd Diehl	Mike Escochea	Jason Franze	Lindi Gomez	Rafael Hernandez	Hunter Kam	Rafael Hernandez	Mark Hughes
John Crooks	Gary Dill	Jarrod Esparza	Jim Fraser	Paul Gomez	Jerry Herren	Christian Kanady	Jerry Herren	Marshall Hughes
Bascom Cropp	Ed Dillard	Jose Espinoza	Annie Fredrickson	Zac Gorsior	Matthew Herrin	Brent Kanaly	Matthew Herrin	Michael Hughes
Jerrad Crosby	Lester Dille	Raul Esquivel	Gregory Freeman	Eric Gonzales	Jerry Herring	Paul Karstens	Jerry Herring	Frank Hutzar
Murphy Crosby	Kelly Dingle	Christopher Estep	Travis Frels	Johnny Gonzales	Kevin Bess	Hemant Kataria	Kevin Bess	Allen Hummel
Paul Crow	David Dison	Tommy Estep	Colby Friday	Stevie Gonzales	Weston Hesterly	Troy Keel	Chris Humphreys	Chris Humphreys
Genique Crowder	Robert Dison	Craig Estes	John Fritcher	Alberto Gonzales	Jamie Hibbs	Richard Keeler	Kirk Hungeford	Tony Hansen
Mary Cruikshank	Linda Dixon	Eddie Estes	Charles D. Frizzell	Alfredo Gonzalez	Danny Hicks	Marvin Keeling Jr.	Danny Hicks	Randy Hansford
Billy Crum	Jeffery Dixon	Phillip Ethenridge	Charlie C. Frizzell	April Gonzalez	James Hicks	Kenneth Keeton	James Hicks	Dustin Hanson
Carman Cuzmadia	Michelle Dodd	Jonathan Fubank	Kimberly Frost	Edgar Gonzalez	Joe Hicks	Kenneth Keeton	Joe Hicks	Edgar Gonzalez
Calvin Culppepper	Tracei Dodd	David Evans	Larry Frost	Gerardo Gonzalez	Tami Hunter	Larry Keller	Terry Hicks	Josh Hardie
Casey Culppepper	Thomas Doman	Donald Evans	William Fry	Guadalupe Gonzalez	John Hurt Jr.	Larry Keller	Lorie Higginbotham	Dean Harding
Melissa Cummins	Max Dominguez	Gary Evans	Sam Frydenlund	Hector Gonzalez	Michael Huston	Diana Kelley	Jennifer Higgins	Mark Harding
Steven Cummings	Nicolas Dominguez	Jody Evans	James Fryman	Julio Gonzalez	Randy Hutchinson	Tommy Kelley	Keith Hightower	James Hardway
Kevin Cunningham	Gary Donley	Ronald Evans	Gilberto Fuentes-Perez	Moises Gonzalez Jr.	Chad Hill	Tracy Kelting	Chad Hill	Ryan Harkins

Sammy Kendall	Kelly Lawson	Scott Mahaffey	Richard McGuire	Santiago Miranda	Gary Murry	David Parker	Brian Powell	Chris Rice
Kris Kendrick	Tom Layman	Ricky Mahon	Rocky McGuire	Tracy Miskofsky	Matt Murry	Edwin Parker	Jerry Powell Jr.	Josh Richardson
Burke Kennedy	Daniel Le	Jesus Maldonado	John McGuire Jr.	Brian Mitchell	Chris Nair	Jeffery Parker Jr.	Jordan Powell	Cori Riches
James Kennedy	Marc Leach	Jorge Maldonado	Christopher McHenry	Jerry Mitchell	George Nakutis	Joshua Parker	Jesus Prado	Jackie Riddle Jr.
Josh Kennedy	Randall Leach	Juan Maldonado	Curtis McIntyre	Brennan Moates	Glenn Nance	Julie Parker	Kenneth Prangler	Scott Riddle
Stephanie Kennedy	Garrett Leatherman	Ramon Maldonado	Irma McIntyre	George Moats Jr.	Lauren Nashert	Toby Parker	Corey Prater	Henry Riffe
Joe Ketzner	James LeBouef	Monica Malkey	Chad McKamie	Chris Mobley	Antoinette Nell	Cole Parkhurst	Sindy Prescott	Patrick Riley
Moin Khan	Summer Leibetter	Melvin Manchack Jr.	Dennis McKamie	Corey Mobley	J.W. Nelson	Phillip Parnellee	Joseph Presock	Sandi Riley
Gil Kiaba	Ryan Lee	John Mann	Janice Modisette	John McKay	Laverne Nelson	Carla Parrish	Marsha Presock	Cody Ripley
George Kidd	Samuel Lee	James Manning	Keith Moffatt	Joshua McKee	Rodney Nelson	Raylon Parrish	Joseph Price	Larry Ritter
Russell Kidd	Stanley Lee	Kevin Manning	Jackie Moffett	Brad McKillop	Thomas Neswick	Cindy Parsons	Mike Price	Greg Rivera
John Kieschnick	William Lee Jr.	Juan Manriquez	Samuel Mohler	Patrick McKim	Lacey Neuman	Marc Passmore	Kevin Pride	Amanda Robbins
Paul Kiespert Jr.	George Leist	Jim Manny	Mohammad	Eric McKinley	Kyle Nevels	Joshua Pate	Chase Pritchett	Rick Robbins Jr.
Jeff Kiker	Martha Leva	Kerry Manuel	Moinuddin	Lincoln McKinzie	Bobby New	Umesh Patel	Randall Pritchett	Courtney Roberts
James Killen	Erin Lennart	Laura Marcellus	Jeremy Moler	Heather McLain	Jere Newberry	Charles Patrick Jr.	Caleb Procell	Jeffrey Roberts Jr.
Kevin Killingsworth	Dave Leopold	Britt Marchbanks	John Moles	Jason McLain	Travis Newberry	Buba Patterson	Chester Prouty Jr.	Josh Roberts
Wayne Kimberling	Michael Lesney Jr.	Justin Marietta	Angela Moniger	Amy McLanahan	Christopher Newark	Michael Patterson	Elizabeth Prykryl	Matthew Roberts
Debbie Kimble	Stacy Levescy	Gary Marks	Leah Monroe	Leah McLarty	Brock Newman	Monte Patterson	Elmer Pryor	Mike Roberts
John Kimbleton	Justin Wellen	Markus Marr	Andrew Montgomery	Walter McLaughlin	Shane Newman	John Paul	Ricky Pryor	Nicole Roberts
Fay Kincher	Carey Lewis	Jonathan Marsh	Bud Moody	Aaron McLean	Eric Newman Jr.	Steven Paul	Omar Puentes	Raymond Roberts
Cory King	John Lewis	Bryan Martin	Tom Mooney	Kippy McLelland	Cheyenne Newsom	Michael Payne	Jerry Pugh	Stacy Roberts
George King	Harold Lewis	Charles Martin	Billy Moore Jr.	Caleb McLoud	Rodney Newton	Rickey Payton	Mandi Pulliam	Vincent Roberts
Jeremiah King	Matthew Lewis	James Martin	Chris Moore	Matthew McMahon	Lori Nguyen	Daniel Pearce	Ronald Putman	Daniel Robertson
Jessica King	Nathan Lewis	Patty Martin	Craig Moore	Steve McMillen	Thomas Nguyen	Blain Pearson	Matt Queen	Michael Robertson
Joshua King	Peter Lewis	Braulio Martinez	Deanne Moore	Christopher McMillian	Scott Nichols	Chester Pearson	Maria Quezada	Scott Robertson
Richard King	Rodney Lewis	Gilbert Martinez	John Moore	Beau McMillin	Kara Nicholson	Kim Pearson	Barbie Quinn	Brooke Robinette
Steven King	Shane Lewis	Luis Martinez	Josh Moore	Bobby McMories	Sonny Nichter	Heriberto Pedroza	Mary Quinn	Scott Robinson
Aaron Kinney	Karen Liles	Mario Martinez	Michael Moore	Larry Moore	Tyler Niederriter	Jerry Peck	Fernando Quinones	Paul Rodeseay
Nathan Kinney	Jim Lindley	Mark Martinez	Roy Moore	Heather McNeil	Nick Niemann	John Peck Sr.	Tyson Raasch	John Rodgers
Rachel Kircher	Lynn Lindsay	Valente Martinez	Spencer Moore	Jason McVellie	Billy Nixon	Ariel Pena	James Rachal	Andrew Rodriguez III
John Kirkham	Danny Lindsey	Luis Martinez Suarez	Walter Moore	Bob McNutt	David Nixon	Danielle Penland	Daren Rader	Antonio Rodriguez
Jared Kirkwood	Jimmy Linger Jr.	Missy Martin	Derek Morales	Danny McRae	Jason Norbotten	Kevin Pennypacker	Mark Raidt	Joel Rodriguez
Nathan Kirtley	Blake Link	Michael Marunowski	Arturo Morales	Marlie McSwain	Derec Norman	Terry Perdue	Johnny Rains	Luz Rodriguez
Ross Kirtley	Jill Linkenauer	Boyd Maser	Charles Morales	Cameron McWaters	Kristopher Norris	Arturo Perez	Hernenegildo Ramirez	Maria Rodriguez
David Kizer Sr.	Trey Littau	Brian Masters	Guillermo Morales	James McWhorter	Patrick Novak	Catarino Perez	Raul Ramirez	Robert Rodriguez
Dakotah Klein	Misty Little	Jeffery Mathena	Hector Morales	Donnie McWhorter	Drew Nugent	Joe Perez	Raul V. Ramirez	Ruben Rodriguez
Jeffrey Klingel	Robert Littles	John Matheny	Guillermo Morales-	Ed Meade	Rene Nunez	Jose Perez	Peter Ramirez Jr.	Sarah Rodriguez
Aaron Knapp	Monty Lively	Tiffany Mather	Mata	Tom Meadows	Lyndol Nunley	Justin Perot	Bonnie Ramon	Juan Rodriguez-Huerta
Buzz Knapp	Charles Livingston	Stephanie Matheson	Charles Morcel	David Medcalf	Jace Oberst	Addie Pesche	Uvaldo Ramon	Donovan Rodriguez
Steven Knight	Othie Lloyd Jr.	Justin Mathews	Terrill Medicinebird	Terrill Medicinebird	Douglas Peters	Douglas Peters	Arturo Ramos	Eddy Rodriguez
Allen Knippers	Ronald Loeffler	Matthew Matos	Fernando Medina	Fernando Medina	Todd Pettus	Todd Pettus	Jessie Ramos	Jose Anthony Rodriguez
Jeff Knoblock	Donnie Loller	Bobby Matthews	Dennis Meigs	Dennis Meigs	Jeff Phillips	Jeff Phillips	Cody Ramsey	Rodney Rodriguez
Charles Knotts	Jerry Lonewell	Nicholas Matthews	Carroll Morgan	Carroll Morgan	Paul Phillips	Paul Phillips	Greg Ramsey	Fred Rogers
Steve Knowles	Christopher Long	Nathan Mattison	Christopher Morgan	Christopher Morgan	Raddy Phillips	Raddy Phillips	Greg Ramsey	Jeremiah Rogers
Kristy Knox	Clayton Long	Delores Maxwell	Chuck Morgan	Chuck Morgan	Dennis O'Handley	Dennis O'Handley	Monte Ramsey	Jon Rogers
Laurie Knox	Ellen Long	Greg May	Eugene Morgan	Eugene Morgan	Anthony Olivas	Alan Pierce	Timothy Ramsey	Bailey Rollins
Sanjay Kodam	Teresa Long	Jesse May	Jay Morgan	Jay Morgan	Jorge Olivas	Mary Pierce	Boyd Ransom	Kevin Rollins
Freedom Koen	James Looney	Joshua Mayes	John Morgan	John Morgan	Michael Oliver	Joseph Pitcher	Kevin Rash	Joseph Romero Jr.
Denise Koger	Brian Lopez	Michael Mayfield	Roger Morgan	Roger Morgan	Steve Olson	James Pine	Roy Rash	David Romine
Blake Koonce	Monty Lopez	Wes Merchant	Nick Morland	Nick Morland	Daniel Ongley Jr.	Matt Pinion	Glenn Ray	Santos Romo
Nathan Kress	Guadalupe Lopez	Curtis Merilatt	Tim Morphis	Tim Morphis	Heidi Opie	Jeff Pinter	Jimmy Ray	Rocky Root
Muhamed Kuburic	Jaime Lopez	David Merkel	Kristina Morrell	Kristina Morrell	Mark Ogren	Roger Pippins Jr.	Aaron Ream	Danielle Roper
Sunita Kuburic	Willfredo Lopez	Keith Merkel	Anthony Morris	Anthony Morris	Christy Orocco	Lara Pitchford	Joe Reames	Lance Roper
Cameron Kuykendall	Niles Loudenstager	Jared Merle	Derek Morris	Derek Morris	Keith Orrick	Shannon Pitt	Roger Radmond	Leonard Roper
Mike LaGrange	Derek Loudemilk	Lane Merritt	James T. Morris	James T. Morris	Randy Orsburn	Brooke Pittard	Galen Reed	Ryan Roper
Roger Lahti	Candice Love	Fara Mettler	James P. Morris	James P. Morris	Luz Ortiz	Emily Pittman	Sean Reed	Vinson Roper
Shane Lair	Wilbur Love	Justin Metz	Larry Morris	Larry Morris	Patricio Ortiz	Michael Pitzer	Jeremy Reese	Glenn Rose
Hoang Lam	Robert Lovelace	Thomas Mewherter	Mike Morris	Mike Morris	Gregory Orum	Filemon Plascencia-	Raymond Reese	Dennis Ross
Jane Lam	Dustin Lovell	Steven Meyer	Nicholas Morris	Nicholas Morris	Don Osborn	Aceves	Jacob Reeves	James Ross
Tony Lamas	Jennifer Lowther	Barry Michels	Ralph Morris	Ralph Morris	Matthew Osborne	Lynn Platania	Christopher Register Sr.	Michael Ross
Gina Lamb	Silvano Lozada-Luna	Allen Middleman	Shayne Morris	Shayne Morris	Robert Oswald	Charles Platt	James Rehm	Richard Ross
Dennis Lambert Jr.	Matthew Lucas	Adam Miller	Steven Morris	Steven Morris	Darrel Overgaard	Nicholas Platt	Bradford Reid	Richelle Ross
Jack Lambert	Jesus Lucio	Drew Miller	Billy Morsko	Billy Morsko	Casey Overhultz	Lori Plumley	Perry Reid	Robert Ross
Janie Lambert	Allen Luder	Dusty Miller	Jeffery Mortashed	Jeffery Mortashed	De Overstreet	Matthew Plummer	Keith Reighler	Tommy Ross
Jerry Lambert Jr.	Kelly Luikart	Greg R. Miller	Joe Mortashed	Joe Mortashed	Thomas Overstreet III	Richard Pogue	John Reinhart	Mathew Rosser
Robert Lambert	David Luke	Gregory W. Miller	Eric Morton	Eric Morton	April Owens	Glenda Pohl	Brad Rekieta	Greg Rossmann
Floyd Lancaster	Charlie Lumpkin III	James Miller	James Moses	James Moses	Lacey Owens	David Poindexter	Allen Remmers	Scott Rutruck
Corbin Land	Shaun McDaniel	Matthew Miller	James Moss	James Moss	Tammie Owens	Randy Poindexter	Carl Renfrow	Yury Rotba
Sandra Landgraaf	Stephen McDonald	Rickey Miller	Jason Moxley	Jason Moxley	Chris Pace	Richard Poindexter	Santhanaaral Rengasah	Sammy Roundtree
Bob Langdon	David McDougal	Ronald Miller	Kevin Moxley	Kevin Moxley	Thomas Pace	Shane Poindexter	Matt Reser	Jennifer Roush
Joshua Langford	Jenni McEachern	Stephen Miller	Jason Mueller	Jason Mueller	David Pacheco	DeAngelo Polin	Aaron Reyburn	Andrew Roviscanec
Matt Lansford	Tommy McEachern	Tom Miller	Johnathan Mueller	Johnathan Mueller	Raymond Pacula	David Polve	Brad Reyes	Loni Rowan
Diane Larch	Russell McLeroy	Allen Miller II	Brad Mulkey	Brad Mulkey	Gerardo Palacio	Gerald Polve	Jorge Reyes	David Rowland
B.J. Larman	Kelle McEwen	Chuck Miller II	Jason Mullins	Jason Mullins	Lindsay Palazzolo	Kenny Polve	Manuel Reyes	Daniel Rucker
Stephen LaRoux	Ray McFarland	Toni Millican	Vicky Mullins	Vicky Mullins	Janie Palma	Matthew Pompa	Roger Reyes	Eric Rucker
Mike Latshaw	Harry McGarr	Caleb Mills	Greg Mummie II	Greg Mummie II	Brian Palmer	David Ponce	Sergio Reyes	Ricky Rucker
Chris Lauthon	Will McGarry	Audrey Mims	Lewis Munn	Lewis Munn	Kurt Palmer	Taos Pool	Allen Reynolds	Richard Ruffo
John Lawman	Meghan McGhee	Benjamin Miner	Julie Murcer	Julie Murcer	Robert Palmer Jr.	Timothy Poole	Justin Reynolds	Joe Ruiz
Clint Lawrence	Terry McGhee	Benjamin Miner	Russell Murphy Jr.	Russell Murphy Jr.	Brnan Panetta	Henry Pope	Jared Rhoads	Michael C. Rushing
Johnny Lawrence	Todd McGinley	Jerame Mink	Danny Murray	Danny Murray	Betty Paolini	Raymond Posey	Chris Rhodes	Michael R. Rushing
Michael Lawrence	Donald McGinnis	Donald Minkler IV	Jason Murray	Jason Murray	Bob Paolini	Nick Pottmeyer	Larry Rhodes	Allen Russell
Corey Lawson	Jamie Maddy	John McGowen	Brandon Murry	Brandon Murry	Candy Parker	Michael Powdrill	Amanda Rhynes	Dena Russell

Don Russell	Jerry Shifflett	Pam Soltani	Chelsea Tanimoto	Tom Treece	Kelli Waligora	Michael Wheless	Robbie Wisdom
Jackie Russell	Kurt Shipley	James Sondakh	Kevin Tanner	Ignacio Trevino Jr.	Erin Walker	Grant Whipple	Amos Wise
Dusty Rust	Mark Shipley	Bradley Sooter	Larry Tanner	Juan Trevino	Noah Walker	Sam Whitaker	Jennifer Wismer
Tracy Rust	Michael Shipley	Jessica Sorrels	Carl Tapp Jr.	Matthew Triplett	Christopher Wallace	Bob Whitbeck	Sara Withrow
Jason Ruth	Mandie Shipman	Ryan Sosnowski	Joseph Tarno	Tallie Triska	Oscar Wallace	Billy White	Graig Wittenhagen
Matthew Rutledge	Steve Shire	Becky Southerland	Ronnie Tarver	Lee Trisler	Rufus Wallace II	Gary White	Brad Wittrock
Norman Sadler	Steven Shockley	Joshua Southerland	David Tarwater	Dominic Trivitt	Jason Wallgren	James B. White	Ivan Wolanski
Al Salas	Chad Shoffner	Julia Southern	Donny Taulbee Jr.	Matthew Troup	Brian Wallis	James K. White	Ray Wolf
Filepe Salinas	Richard Southern	Richard Southern	Alan Taylor	Danny Trowbridge	Donnie Wallis	Jerry D. White	Colby Wolfe
Gurpreet Saluja	Pete Spadafora	Pete Spadafora	David Taylor	Carol Troy	Matthew Walls	Jerry D. White, Jr.	David Wolfe
Uriel Samaniego	Kelly Sparks	Shad Sparks	Jack Taylor	Daniel Truong	Norman Walls	Trent White	Zachary Wolfe
Shirley Sample	Jesus Sierra	Meghan Spears	Jimmy Taylor	Brent Tucker	Clay Walters	Christy Whited	Mark Wood
Corwin Sampson	Pedro SiFuentes-Deleon	Rodney Spencer	Matthew Taylor	Irina Tucker	Mathew Walters	Bernice Whiteshirt	Mathew Wood
Lloyd Sanders Jr.	Andrew Sikoryak	Lou Spitznogle	Mike Taylor	Ryan Tucker	Kathy Wandling	Joe Whiteside	Mike Wood
Matthew Sanders	Vincent Silk	Derek Spreier	Rick Taylor	Jerry Tune	David Wanzer	Shawn Whiteside	Tammy Wood
Steven Sanders	Gregorio Silva	Gregorio Silva	Sarah Taylor	Steve Turk	Elmer Warnick	Jason Whitt	Toby Wood
Dale Sanderson	Terry Simmons	Todd Springer	Timmy Taylor	Chris Turner Jr.	Joseph Warren	Easton Whyel	Randy Woodcox
Henry Satoe	Donald Simons	Rene St. Pierre	Vanessa Taylor	Cory Turner	Matt Warren	Joshua Whyel	Henry Woodruff
John Satterfield II	C.J. Sims	Steven Stafford	Andrew Tencer	Dwayne Turner	Will Warren	Robert Whiggins	Larry Woodruff
Justin Sauls	Christopher Sims	Allen Staggers	Nicholas Terech	Jaffe Turner	Craig Wassana	Annette Wilborne	Tara Woods
Terry Sauborn	Mary Sims	Craig Staley	Daniel Terry	Marcus Turner	Marc Watkins	Jeffrey Wilborn	Dan Woodzell
Krystal Sawatzky	Randy B. Sims	Jason Staley	David Terry	Joshua Turso	Matt Watkins	Kyle Wiley	Rick Worley
Phillip Saxon	Randy S. Sims	Terry Stamper	Dustin Terry	Donald Tussey	Bryan Watson	James Wilhite	Shawn Weath
Kiley Scabbyhorse	Rickie Sims	Lynn Standage Jr.	Ross Terry	Joshua Tyer	Dusty Watson	Addie Wilkerson	Bobby Wright
Perry Seales	Rudy Sims Jr.	Howard Stane	Samson Tesfelasie	Luis Valencia	James Watson	Kent Wilkinson	Bradley Wright
Joshua Schlosser	Joe Stanford	Joe Stanford	Brian Thomas	James Van Alstine	Matthew Watson	Earl Willeford	Chris Wright
David Schmidt Jr.	Pixie Stanford	Pixie Stanford	Chad Thomas	Jeffrey Van Grevenhof	Ernest Watts	Roy Willeford	Erran Wright
Shawn Schmidt	Don Stanley Jr.	Don Stanley Jr.	Gwen Thomas	Don Van Horn	Rod Weatherby	Kyle Willey	Larry Wright
Karen Schmuhl	Jeff Stanley	Jeff Stanley	Jason C. Thomas	Jeff Vanata	Gary Weathers	Gindy Williams	Mary Wright
Jason Schnebel	Tiffany Starnes	Tiffany Starnes	Jason D. Thomas	Clyde Vance	Jason Weaver	Eric Williams	Michael Wright
Kenny Schoubroek	Danny Singleton	Danny Singleton	Lacey Thomas	Jeremy Vance	Lauren Webb	Jim Williams	William Wright
Ernest Schroeder	Dusty Singleton	Dusty Singleton	Michael Thomas	Amanda Vanoven	John Weber	Joshua Williams	Greg Wyatt
Richard Schubert	Steven Sinnett	Peter Stephens	Paul Thomas	Hugo Vargas	Charles Webster III	Justin Williams	Ronnie Wyatt
David Schuermann	William Sisson	Robert Stephens	Elizabeth Thompson	Jody Vaughn	John Webster	Kyle Williams	Luke Wyckoff
Michael Schulz	Charles Sitton	Anne Steptoe	Kevin Thompson	Leland Vaughn	Brad Wechsler	Marlene Williams	Keith Yankowsky
Earnest Sconyers	Steve Skellie	David Stevens	Matt B. Thompson	Dakota Vaught	Adam Weddington	Rashaw Williams	Kevin Yarbrough
Bannon Scott	Michael Slamick	Robby Stevens	Matthew R. Thompson	Jody Vaught	Donald Weed	Ricky Williams	Amanda Yardley
Bryan Scott	James Slaten	Roger Stevens	Richard Thompson	Brandi Vawter	Jody Weidner	Thad Williams	Herman Yeager
James Scott	Brian Slaughter	Kirsten Steves	Tim Thompson	Melvin Veach	Thomas Weidner	Vernon Williams	Ronald Yex
Joseph Scott	Bryan Sloan	Bree Stewart	Travis Thompson	Andres Vega-Tobias	Thomas Weier	Zachary Williams	Matthew Yoder
Kelby Scott	Jack Stone	Chris Stewart	Justin Thrift	Arturo Velez	Matt Weinreich	Calvin Williamson Jr.	Duane Yost
Krystle Scott	Nathan Smarr	Lyvonne Stewart	Joel Thronburg	Gerardo Velez	John Weir Jr.	Jeff Willis	Vincent Yost Jr.
Larry Scott	Eric Smeltzer	Mariah Stewart	Patricia Thrower	Terry Vermatter	Michael Welch	Dee Willoughby	Debbie Young
Nathaniel Scott II	Allan Smith	Lamario Stillwell	Martin Tidwell	Michael Vernon	Samuel Welchel	Tyler Williard	Scott Young
Kevin Scoville	Alvis Smith	Jason Stollings	Isidro Tjerina	Randy Villa	P.J. Wells	Andrew Wilson	Ulya Young
Stoney Scrivner	Brian Smith	Michael Stone	Elmo Tillis	Randy Villaire	Robert Wells	Brent Wilson	Mina Zaheri
David Sears	Chad Smith	Eric Stong	James Tincher	Benjamin Villareal	Toya Wells	Chad Wilson	Kilo Zalkdivar
Amy Seor	Shawna Storey	Shawna Storey	Andrew Tipton	Pascual Villarreal	Ann Wendorff	Charles Wilson	Ricky Zanola
Scott Secrest	Richard Stodler Jr.	Richard Stodler Jr.	Brandi Tolley	Dustin Vinson	Darrell Werther	Chuck Wilson	Simon Zavalta
Eric Selfried	Jason Stowasser	Jennifer Stowasser	Keith Tomblin	Brenda Vitatoe	Leonard Wesley	Julie Wilson	Jason Zielke
Dusty Seiger	Michael Strabley	Michael Strabley	Mikki Tomlinson	Billy Vo	Luke Westfahl	Robin Wilson	Jeff Ziga
David Seitz	Andy Streatly	Andy Streatly	Scott Tomlinson	Jonathan Vogel	Christopher Weston	Steve Wilson	Jody Zigler
Debbie Seiverling	Haskell Streater	Haskell Streater	Jerry Toney	Curtis Voyles	Jake Weyrick	Warren Wilson	
Dale Self	William Street Jr.	William Street Jr.	John Toney	Robert Wagoner	William Weyrick	Jim Wimmer	
William Self	Russell Streeter	Russell Streeter	Matt Toppins	Huey Wagstaff	Scotty Wheatley	Franklin Windham	
Kenneth Sell	Carrie Strickland	Carrie Strickland	Brandon Tree	Willie Wainman	David Wheeler	Carl Winslow	
Jobey Sellers	Conward Strickland	Conward Strickland					
Travis Sellers	John Strickland	John Strickland					
Jon Selzer	Ronnie Stroh	Ronnie Stroh					
Louis Senkyrik	Eric Strutton	Eric Strutton					
Michelle Senters	Edwin Stubbart	Edwin Stubbart					
Clint Sepulvado	Jill Stucky	Jill Stucky					
Jerry Sepulvado	Perry Studebaker	Perry Studebaker					
Robert Settle	Yoscel Suarez	Yoscel Suarez					
J.C. Settles	Pear Sudchai	Pear Sudchai					
John Shaffer	Erin Sullins	Erin Sullins					
Brooke Shannon	Teresa Sullivan	Teresa Sullivan					
Douglas Shannon Jr.	Dennis Summers	Dennis Summers					
Jimmy Sharp Jr.	Gary Summers	Gary Summers					
Jimmy Sharp Sr.	John Suter	John Suter					
Wendie Sharp	Roger Sutterfield	Roger Sutterfield					
Farley Shaw	Anastasia Svec	Anastasia Svec					
Frederick Shaw Jr.	Rick Svor	Rick Svor					
Carroll Shearer	Melisa Swart	Melisa Swart					
Garland Shed	Jayce Swartz	Jayce Swartz					
James Sheets	Joshua Swartz	Joshua Swartz					
David Sherkko	Dee Swiger	Dee Swiger					
David Shellsrom	Joseph Swiger	Joseph Swiger					
Jerry Shelton	Kevin Swiger	Kevin Swiger					
Robert Shelton	Benjamin Swiney	Benjamin Swiney					
Michael Sherman	Jose Tabares	Jose Tabares					
Michael Shiers	Colby Tackett	Colby Tackett					



**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, 2006

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:

<u>Title of Each Class</u>	<u>Name of Each Exchange on Which Registered</u>
Common Stock, par value \$.01	New York Stock Exchange
7.5% Senior Notes due 2013	New York Stock Exchange
7.625% 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
6.375% Senior Notes due 2015	New York Stock Exchange
7.75% Senior Notes due 2015	New York Stock Exchange
6.625% Senior Notes due 2016	New York Stock Exchange
6.875% Senior Notes due 2016	New York Stock Exchange
6.5% Senior Notes due 2017	New York Stock Exchange
6.25% Senior Notes due 2018	New York Stock Exchange
6.875% Senior Notes due 2020	New York Stock Exchange
2.75% Contingent Convertible Senior Notes due 2035	New York Stock Exchange
4.5% Cumulative Convertible Preferred Stock	New York Stock Exchange
6.25% Mandatory Convertible Preferred Stock	New York Stock Exchange

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

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES NO

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. YES NO

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 a large accelerated filer, an accelerated filer or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large accelerated filer Accelerated filer Non-accelerated filer

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES NO

The aggregate market value of our common stock held by non-affiliates on June 30, 2006 was approximately \$11.9 billion. At February 23, 2007, there were 460,068,149 shares of our \$0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2007 Annual Meeting of Shareholders are incorporated by reference in Part III.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

2006 ANNUAL REPORT ON FORM 10-K

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PART I

ITEM 1. *Business*

General

We are the third largest independent producer of natural gas in the United States, and we own interests in approximately 34,600 producing oil and natural gas wells that are currently producing approximately 1.7 billion cubic feet equivalent, or bcfe, per day, 92% of which is natural gas. Our strategy is focused on discovering, developing and acquiring conventional and unconventional natural gas reserves onshore in the U.S. east of the Rocky Mountains. Our operations are located in the *Mid-Continent region*, which includes Oklahoma, Arkansas, southwestern Kansas and the Texas Panhandle; the *Forth Worth Basin* in north-central Texas; the *Appalachian Basin*, principally in West Virginia, eastern Kentucky, eastern Ohio and southern New York; the *Permian and Delaware Basins* of West Texas and eastern New Mexico; the *Ark-La-Tex* area of East Texas and northern Louisiana; and the *South Texas and Texas Gulf Coast regions*. We have established a top-three position in nearly every major shale play in the U.S., including the Fort Worth Basin Barnett Shale, the Arkansas Fayetteville Shale, the Appalachian Basin Devonian Shale, the southeast Oklahoma Woodford Shale, the Delaware Basin Barnett and Woodford Shales, the Illinois Basin New Albany Shale and the Conasauga, Floyd and Chattanooga Shales in Alabama.

As of December 31, 2006, we had 9.0 trillion cubic feet equivalent, or tcf, of proved reserves, of which 93% were natural gas and all of which were onshore. During 2006, we produced an average of 1.585 bcfe per day, a 23% increase over the 1.284 bcfe per day produced in 2005. We replaced our 578 bcfe of production with an internally estimated 2.013 tcf of new proved reserves for a reserve replacement rate of 348%. Reserve replacement through the drillbit was 1.345 tcf, or 233% of production (including 729 bcfe of positive performance revisions and 212 bcfe of downward revisions resulting from natural gas price declines), and reserve replacement through acquisitions was 668 bcfe, or 115% of production. As a result, our proved reserves grew by 19% during 2006, from 7.5 tcf to 9.0 tcf. Of our 9.0 tcf of proved reserves, 62% were proved developed reserves.

During 2006, we led the nation in drilling activity with an average utilization of 98 operated rigs and 79 non-operated rigs. Through this drilling activity, we drilled 1,488 (1,243 net) operated wells and participated in another 1,534 (206 net) wells operated by other companies. Our success rate was 99% for operated wells and 98% for non-operated wells. In 2006, we added approximately 2,000 new employees to support our growth, which increased our total employee base to approximately 4,900 employees at December 31, 2006, and invested \$771 million in leasehold (excluding leasehold acquired through corporate and asset acquisitions) and 3-D seismic data, all of which we consider the building blocks of future value creation.

From January 1, 1998 through December 31, 2006, we were one of the most active consolidators of onshore U.S. natural gas assets, having purchased approximately 6.5 tcf of proved reserves, at a total cost of approximately \$14.3 billion (including \$5.1 billion for unproved leasehold, but excluding \$989 million of deferred taxes established in connection with certain corporate acquisitions). Excluding the amounts allocated to unproved leasehold and deferred taxes, our acquisition cost per proved thousand cubic feet equivalent, or mcf, was \$1.41 over this time period. During 2006, we remained active in the acquisitions market. Acquisition expenditures in 2006 totaled \$4.0 billion (including \$2.9 billion for unproved leasehold, but excluding \$180 million of deferred taxes established in connection with certain corporate acquisitions).

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.

Business Strategy

Since our inception in 1989, Chesapeake's goal has been to create value for investors by building one of the largest onshore natural gas resource bases in the United States. For the past nine years, our strategy to accomplish this goal has been to focus onshore in the U.S. east of the Rockies where the company believes it can generate attractive risk adjusted returns. In building our industry-leading resource base, 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. To date, we have built leading positions in the Mid-Continent region, the Fort Worth Barnett Shale in North Texas, the South Texas and Texas Gulf Coast regions, the Permian and Delaware Basins of West Texas and eastern New Mexico, the Fayetteville Shale in Arkansas, the Ark-La-Tex area of East Texas and northern Louisiana, the Appalachian Basin, principally in West Virginia, eastern Kentucky, eastern Ohio and southern New York, the Caney and Woodford Shales in southeastern Oklahoma, the Barnett and Woodford Shales in west Texas and the Conasauga, Floyd and Chattanooga Shales of Alabama.

Key elements of this business strategy are further explained below:

- *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 approximately 132 operated drilling rigs and approximately 90 non-operated drilling rigs to conduct the most active drilling program in the U.S. We focus both on finding significant new natural gas reserves and developing existing proved reserves, principally at deeper depths than the industry average. For the past nine years, we have been actively investing in leasehold, 3-D seismic information and human capital to be able to take advantage of the favorable drilling economics that exist today. While we believe U.S. natural gas production has declined during the past six years, we are one of the few large-cap independent oil and natural gas companies that have been able to increase production, which we have successfully achieved for the past 17 consecutive years and 22 consecutive quarters. We believe key elements of the success and scale of our drilling programs have been our early recognition that natural gas prices were likely to move higher in the U.S. in the post-2000 period accompanied by our willingness to proactively hire new employees and to build the nation's largest onshore leasehold and 3-D seismic inventories, all of which are the building blocks of a successful large-scale drilling program.
- *Make High-Quality Acquisitions.* Our acquisition program is focused on 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, 2006, we purchased approximately 6.5 tcf of proved reserves, at a total cost of approximately \$14.3 billion (including \$5.1 billion for unproved leasehold, but excluding \$989 million of deferred taxes established in connection with certain corporate acquisitions). Excluding the amounts allocated to unproved leasehold and deferred taxes, our acquisition cost per proved mcfe was \$1.41 over this time period. The majority of these acquisitions either increased our ownership in existing wells or fields or added additional drilling locations in our focused operating areas. Because these operating areas contain many smaller 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.
- *Focus on Low Costs.* By minimizing lease operating costs and general and administrative expense 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 management's effective cost-control programs, a high-quality asset base and extensive and competitive services, natural gas processing and transportation infrastructures that exist in our key operating areas. In addition, to control costs and service quality we have made significant investments in our drilling rig and trucking service operations and in our midstream gathering and compression operations. As of December 31, 2006, we operated approximately 20,400 of our 34,600 wells, which delivered approximately 83% of our daily production volume. This large percentage of operated properties provides us with a high degree of operating flexibility and cost control.

- *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 that share many similar geological and operational characteristics. 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 region in late 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 Mountains in current U.S. natural 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 97% over the past 17 years, 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 the other areas where we operate possess many of these same favorable characteristics and our goal is to become or remain a top three natural gas producer in each of our operating areas.
- *Improve our Balance Sheet.* We have made significant progress in improving our balance sheet over the past eight years. From December 31, 1998 through December 31, 2006, we increased our stockholders' equity by \$11.5 billion through a combination of earnings and common and preferred equity issuances. As of December 31, 2006, our debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders' equity) was 40%, compared to 47% as of December 31, 2005 and 137% as of December 31, 1998. We believe our business strategy and operational performance will lead to an investment grade credit rating for our unsecured debt in the future.

Based on our view that natural gas will be in a tight supply/demand relationship in the U.S. during at least the next few years because of the significant structural challenges to growing natural gas supply and the 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 14% to 18% in 2007 and 10% to 14% in 2008.

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 onshore natural gas. Based upon current production and proved reserve estimates, our proved reserves-to-production ratio, or reserve life, is approximately 14.5 years. In addition, we believe we are the seventh largest producer of natural gas in the U.S. (third among independents) and the fifth largest owner of proved U.S. natural gas reserves (second among independents). 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.
- *Large Inventory of Drilling Projects.* During the 17 years since our inception, we have been among the five most active drillers of new wells in the U.S. Presently, we are the most active driller in the U.S. with 132 operated and 90 non-operated rigs drilling. 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 conventional and unconventional reservoirs. As a result of our successful acquisition program and active leasehold acquisition and seismic acquisition

strategies, we have been able to accumulate a U.S. onshore leasehold position of approximately 10.4 million net acres, and have acquired rights to 16.3 million acres of onshore 3-D seismic data to provide informational advantages over our competitors and to help evaluate our large acreage inventory. On this very large acreage position, our technical teams believe we have approximately 26,000 net exploratory and developmental drilling locations, representing a backlog of approximately 10 years of future drilling opportunities at current drilling rates.

- *Successful Acquisition Program.* Our experienced 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, generally favorable basis differentials to benchmark commodity prices, well-developed oil and natural gas transportation infrastructures and considerable potential for further consolidation of assets. Since 1998, we have acquired approximately 6.5 tcf of proved reserves that replaced 270% of our total production. We believe we are well-positioned to continue making attractive 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 experience in the regions in which we operate.
- *Low-Cost Producer.* Our high-quality asset base, the work ethic of our employees, our hands-on management style and our headquarters location in Oklahoma City have enabled us to achieve a low operating and administrative cost structure. During 2006, our operating costs per unit of production were \$1.40 per mcf, which consisted of general and administrative expenses of \$0.24 per mcf (including non-cash stock-based compensation of \$0.05 per mcf), production expenses of \$0.85 per mcf and production taxes of \$0.31 per mcf. We believe this is one of the lowest cost structures among publicly-traded, large-cap independent oil and natural gas producers.
- *Effective Hedging Program.* We have used and intend to continue using hedging programs to reduce the risks inherent in acquiring and producing oil and natural gas reserves, commodities that are frequently characterized by significant price volatility. We believe this price volatility is likely to continue in the years ahead and that we can use this volatility to our benefit by taking advantage of prices when they reach levels that management believes are either unsustainable for the long-term or provide unusually high rates of return on our invested capital. We currently have natural gas swaps in place covering 48% and 60% of our anticipated natural gas production for 2007 and 2008, respectively, at average NYMEX prices of \$8.63 and \$9.20 per mcf, respectively, along with natural gas collars covering 10% of our anticipated natural gas production for 2007 with an average NYMEX floor of \$6.88 per mcf and an average NYMEX ceiling of \$8.41 per mcf. Additionally, we have written call options covering 10% and 13% of our 2007 and 2008 natural gas production, respectively, at a weighted average price of \$9.56 and \$10.20 per mcf, respectively. We have oil swaps in place covering 59% and 51% of our anticipated oil production for 2007 and 2008, respectively, at average NYMEX prices of \$71.90 and \$71.63 per barrel of oil, respectively. During 2006, we realized gains from our hedging program of approximately \$1.254 billion, which increased our realized price per mcf by \$2.17.
- *Entrepreneurial Management.* Our management team formed the company in 1989 with an initial capitalization of \$50,000 and fewer than ten employees. Since then, our management team has guided the company through various operational and industry challenges and extremes of oil and natural gas prices to create the third largest independent producer of natural gas in the U.S. with approximately 4,900 employees and an enterprise value of approximately \$23.8 billion. Our chief executive officer and co-founder, Aubrey K. McClendon, has been in the oil and natural gas industry for 25 years and beneficially owns, as of February 23, 2007, approximately 25.8 million shares of our common stock.

Properties

Chesapeake focuses its natural gas exploration, development and acquisition efforts in six operating areas: (i) the Mid-Continent, representing 47% of our proved reserves, (ii) the Fort Worth Basin, representing 13% of our proved reserves, (iii) the Appalachian Basin, representing 17% of our proved reserves, (iv) the Permian and Delaware Basins, representing 8% of our proved reserves, (v) the Ark-La-Tex area, representing 8% of our proved reserves, and (vi) the South Texas and Texas Gulf Coast regions, representing 7% of our proved reserves.

Chesapeake's strategy for 2007 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 2007 production will be between 665 bcfe and 675 bcfe. We have budgeted \$4.7 billion to \$4.9 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 and borrowings under our revolving bank credit facility. Our budget is frequently adjusted based on changes in oil and natural 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, if needed, new debt and equity issuances.

Operating Areas

Mid-Continent. Chesapeake's Mid-Continent proved reserves of 4.226 tcf represented 47% of our total proved reserves as of December 31, 2006, and this area produced 315 bcfe, or 55%, of our 2006 production. During 2006, we invested approximately \$1.530 billion to drill 1,884 (621 net) wells in the Mid-Continent. For 2007, we anticipate spending approximately 37% of our total budget for exploration and development activities in the Mid-Continent region.

Fort Worth Barnett Shale. Chesapeake's Fort Worth Barnett Shale proved reserves represented 1.141 tcf, or 13%, of our total proved reserves as of December 31, 2006. During 2006, the Fort Worth Barnett Shale assets produced 44 bcfe, or 7%, of our total production. During 2006, we invested approximately \$428 million to drill 244 (187 net) wells in the Fort Worth Barnett Shale. For 2007, we anticipate spending approximately 26% of our total budget for exploration and development activities in the Fort Worth Barnett Shale.

Appalachian Basin. Chesapeake's Appalachian Basin proved reserves represented 1.491 tcf, or 17%, of our total proved reserves as of December 31, 2006. During 2006, the Appalachian assets produced 45 bcfe, or 8%, of our total production. During 2006, we invested approximately \$171 million to drill 319 (272 net) wells in the Appalachian Basin. For 2007, we anticipate spending approximately 7% of our total budget for exploration and development activities in the Appalachian Basin.

Permian and Delaware Basins. Chesapeake's Permian and Delaware Basins proved reserves represented 725 bcfe, or 8%, of our total proved reserves as of December 31, 2006. During 2006, the Permian assets produced 49 bcfe, or 8%, of our total production. During 2006, we invested approximately \$413 million to drill 189 (92 net) wells in the Permian and Delaware Basins. For 2007, we anticipate spending approximately 13% of our total budget for exploration and development activities in the Permian and Delaware Basins.

Ark-La-Tex. Chesapeake's Ark-La-Tex proved reserves represented 711 bcfe, or 8%, of our total proved reserves as of December 31, 2006. During 2006, the Ark-La-Tex assets produced 46 bcfe, or 8%, of our total production. During 2006, we invested approximately \$381 million to drill 248 (175 net) wells in the Ark-La-Tex region. For 2007, we anticipate spending approximately 9% of our total budget for exploration and development activities in the Ark-La-Tex area.

South Texas and Texas Gulf Coast. Chesapeake's South Texas and Texas Gulf Coast proved reserves represented 661 bcf, or 7%, of our total proved reserves as of December 31, 2006. During 2006, the South Texas and Texas Gulf Coast assets produced 79 bcf, or 14%, of our total production. For 2006, we invested approximately \$375 million to drill 138 (102 net) wells in the South Texas and Texas Gulf Coast regions. For 2007, we anticipate spending approximately 8% of our total budget for exploration and development activities in the South Texas and Texas Gulf Coast regions.

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.

	2006				2005				2004			
	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent
Development:												
Productive	2,844	98%	1,364	99%	1,736	97%	735	97%	1,239	97%	463	98%
Non-productive	47	2	13	1	51	3	21	3	34	3	9	2
Total	<u>2,891</u>	<u>100%</u>	<u>1,377</u>	<u>100%</u>	<u>1,787</u>	<u>100%</u>	<u>756</u>	<u>100%</u>	<u>1,273</u>	<u>100%</u>	<u>472</u>	<u>100%</u>
Exploratory:												
Productive	128	98%	71	99%	177	98%	57	95%	164	92%	67	91%
Non-productive	3	2	1	1	4	2	3	5	14	8	7	9
Total	<u>131</u>	<u>100%</u>	<u>72</u>	<u>100%</u>	<u>181</u>	<u>100%</u>	<u>60</u>	<u>100%</u>	<u>178</u>	<u>100%</u>	<u>74</u>	<u>100%</u>

The following table shows the wells we drilled by area:

	2006		2005		2004	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Mid-Continent	1,884	621	1,442	498	1,195	417
Fort Worth Barnett Shale	244	187	—	—	—	—
Appalachian Basin	319	272	15	11	—	—
Permian and Delaware Basins	189	92	139	56	107	55
Ark-La-Tex	248	175	257	171	82	36
South Texas and Texas Gulf Coast	138	102	115	80	67	38
Total	<u>3,022</u>	<u>1,449</u>	<u>1,968</u>	<u>816</u>	<u>1,451</u>	<u>546</u>

At December 31, 2006, we had 270 (128 net) wells in process.

Well Data

At December 31, 2006, we had interests in approximately 34,600 (19,079 net) producing wells, including properties in which we held an overriding royalty interest, of which 6,500 (3,608 net) were classified as primarily oil producing wells and 28,100 (15,471 net) were classified as primarily natural gas producing wells. Chesapeake operates approximately 20,400 of its 34,600 producing wells. During 2006, we drilled 1,488 (1,243 net) wells and participated in another 1,534 (206 net) wells operated by other companies. We operate approximately 83% of our current daily production volumes.

Production, Sales, Prices and Expenses

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

	Years Ended December 31,		
	2006	2005	2004
Net Production:			
Oil (mbbls)	8,654	7,698	6,764
Natural gas (mmcf)	526,459	422,389	322,009
Natural gas equivalent (mmcfe)	578,383	468,577	362,593
Oil and Natural Gas Sales (\$ in thousands):			
Oil sales	\$ 526,687	\$ 401,845	\$ 260,915
Oil derivatives—realized gains (losses)	(14,875)	(34,132)	(69,267)
Oil derivatives—unrealized gains (losses)	28,459	4,374	3,454
Total oil sales	<u>\$ 540,271</u>	<u>\$ 372,087</u>	<u>\$ 195,102</u>
Natural gas sales	\$3,343,056	\$3,231,286	\$1,789,275
Natural gas derivatives—realized gains (losses)	1,268,528	(367,551)	(85,634)
Natural gas derivatives—unrealized gains (losses)	467,039	36,763	37,433
Total natural gas sales	<u>\$5,078,623</u>	<u>\$2,900,498</u>	<u>\$1,741,074</u>
Total oil and natural gas sales	<u>\$5,618,894</u>	<u>\$3,272,585</u>	<u>\$1,936,176</u>
Average Sales Price			
(excluding gains (losses) on derivatives):			
Oil (\$ per bbl)	\$ 60.86	\$ 52.20	\$ 38.57
Natural gas (\$ per mcf)	\$ 6.35	\$ 7.65	\$ 5.56
Natural gas equivalent (\$ per mcfe)	\$ 6.69	\$ 7.75	\$ 5.65
Average Sales Price			
(excluding unrealized gains (losses) on derivatives):			
Oil (\$ per bbl)	\$ 59.14	\$ 47.77	\$ 28.33
Natural gas (\$ per mcf)	\$ 8.76	\$ 6.78	\$ 5.29
Natural gas equivalent (\$ per mcfe)	\$ 8.86	\$ 6.90	\$ 5.23
Other Operating Income (\$ per mcfe):			
Oil and natural gas marketing	\$ 0.09	\$ 0.07	\$ 0.05
Service operations	\$ 0.11	\$ —	\$ —
Expenses (\$ per mcfe):			
Production expenses	\$ 0.85	\$ 0.68	\$ 0.56
Production taxes	\$ 0.31	\$ 0.44	\$ 0.29
General and administrative expenses	\$ 0.24	\$ 0.14	\$ 0.10
Oil and natural gas depreciation, depletion and amortization	\$ 2.35	\$ 1.91	\$ 1.61
Depreciation and amortization of other assets	\$ 0.18	\$ 0.11	\$ 0.08
Interest expense (a)	\$ 0.52	\$ 0.47	\$ 0.45

(a) Includes the effects of realized gains or (losses) from interest rate derivatives, but does not include the effects of unrealized gains or (losses) and is net of amounts capitalized.

Oil and Natural Gas Reserves

The tables below set forth information as of December 31, 2006 with respect to our estimated proved reserves, the associated estimated future net revenue and present value (discounted at an annual rate of 10%) of estimated future net revenue before and after income tax (standardized measure) at such date. Neither the pre-tax present value of estimated future net revenue nor the after-tax standardized measure is intended to represent the current market value of the estimated oil and natural gas reserves we own.

	December 31, 2006		
	Oil (mdbl)	Gas (mmcf)	Total (mmcfe)
Proved developed	76,705	5,113,211	5,573,441
Proved undeveloped	29,325	3,206,223	3,382,173
Total proved	106,030	8,319,434	8,955,614
	Proved Developed	Proved Undeveloped	Total Proved
		(\$ in thousands)	
Estimated future net revenue (a)	\$22,164,254	\$8,225,842	\$30,390,096
Present value of estimated future net revenue (a)	\$11,292,561	\$2,354,580	\$13,647,141
Standardized measure (a)(b)			\$10,006,571

	Oil (mdbl)	Gas (mmcf)	Gas Equivalent (mmcfe)	Percent of Proved Reserves	Present Value (\$ in thousands)
Mid-Continent	52,432	3,911,275	4,225,867	47%	\$ 6,948,701
Fort Worth Barnett Shale	91	1,140,833	1,141,379	13	1,310,275
Appalachian Basin	957	1,485,446	1,491,188	17	1,652,134
Permian and Delaware Basins	42,284	471,452	725,156	8	1,495,751
Ark-La-Tex	5,661	677,473	711,439	8	819,272
South Texas and Texas Gulf Coast	4,605	632,955	660,585	7	1,421,008
Total	106,030	8,319,434	8,955,614	100%	\$13,647,141(a)

- (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, 2006. The prices used in our external and internal reserve reports yield weighted average wellhead prices of \$56.25 per barrel of oil and \$5.41 per mcf of natural gas. These prices should not be interpreted as a prediction of future prices, nor do they reflect the value of our commodity hedges in place at December 31, 2006. The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization. Estimated future net revenue and the present value thereof differ from future net cash flows and the standardized measure thereof only because the former do not include the effects of estimated future income tax expenses (\$3.64 billion as of December 31, 2006).

Management uses future net revenue, which is calculated without deducting estimated future income tax expenses, and the present value thereof as one measure of the value of the company's current proved reserves and to compare relative values among peer companies without regard to income taxes. We also understand that securities analysts and rating agencies use this measure in similar ways. While future net revenue and present value are based on prices, costs and discount factors which are consistent from company to company, the standardized measure of discounted future net cash flows is dependent on the unique tax situation of each individual company.

- (b) The standardized measure of discounted future net cash flows is calculated in accordance with SFAS 69. Additional information on the standardized measure is presented in Note 11 of the notes to our consolidated financial statements included in Item 8 of this report.

As of December 31, 2006, our reserve estimates included 3.382 tcf of reserves classified as proved undeveloped (PUD). Of this amount, approximately 40%, 34% and 16% (by volume) were initially classified as PUDs in 2006, 2005 and 2004, respectively, and the remaining 10% were initially classified as PUDs prior to 2004. Of our proved developed reserves, 655 bcf are non-producing, which are primarily "behind pipe" zones in producing wells.

The future net revenue attributable to our estimated proved undeveloped reserves of \$8.2 billion at December 31, 2006, and the \$2.4 billion present value thereof, have been calculated assuming that we will expend approximately \$6.2 billion to develop these reserves. We have projected to incur \$2.7 billion in 2007, \$1.4 billion in 2008, \$0.8 billion in 2009 and \$1.3 billion in 2010 and beyond, although the amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs, product prices and the availability of capital. 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.

Chesapeake employed third-party engineers to prepare independent reserve forecasts for approximately 80% of our proved reserves (by volume) at year-end 2006. These are not audits or reviews of internally prepared reserve reports. The estimates of the proved reserves evaluated by third-party engineers were within 99% of the company's own estimates and were used instead of our estimates for booking purposes. Netherland, Sewell & Associates, Inc. evaluated 32%, Data and Consulting Services, Division of Schlumberger Technology Corporation evaluated 16%, Lee Keeling and Associates, Inc. evaluated 14%, Ryder Scott Company L.P. evaluated 10% and LaRoche Petroleum Consultants, Ltd. evaluated 8% of our estimated proved reserves by volume at December 31, 2006. The estimates prepared by the independent firms covered approximately 18,000 properties, or 40% of the 45,000 properties included in the 2006 reserve reports. Because, in management's opinion, it would be cost prohibitive for third-party engineers to evaluate all of our wells, we have prepared internal reserve forecasts for approximately 20% 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 or field.

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 natural gas production sold subsequent to December 31, 2006. 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 natural 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 natural 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. 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 the December 31, 2006 present value of estimated future net revenue of our proved reserves of approximately \$350 million and \$50 million, respectively. The estimated future net revenue used in this analysis does not include the effects of future income taxes or hedging. 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.

The company's estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2006, 2005 and 2004, and the changes in quantities and standardized measure of such reserves for each of the three years then ended, are shown in Note 11 of the notes to the consolidated financial statements included in Item 8 of this report.

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:

	December 31,		
	2006	2005	2004
	(\$ in thousands)		
Acquisition costs:			
Proved properties	\$1,175,616	\$3,554,651	\$1,541,920
Unproved properties	2,855,848	1,375,675	570,495
Deferred income taxes	179,731	251,722	463,949
Total	<u>4,211,195</u>	<u>5,182,048</u>	<u>2,576,364</u>
Development costs:			
Development drilling (a)	2,772,149	1,566,730	863,268
Leasehold acquisition	616,550	290,946	110,530
Asset retirement obligation and other	23,214	52,619	41,924
Total	<u>3,411,913</u>	<u>1,910,295</u>	<u>1,015,722</u>
Exploration costs:			
Exploratory drilling	348,703	253,341	128,635
Geological and geophysical (b)	153,993	70,901	55,618
Total	<u>502,696</u>	<u>324,242</u>	<u>184,253</u>
Sales of oil and natural gas properties	(118)	(9,769)	(12,048)
Total	<u>\$8,125,686</u>	<u>\$7,406,816</u>	<u>\$3,764,291</u>

(a) Includes capitalized internal cost of \$147.3 million, \$94.1 million and \$45.4 million, respectively.

(b) Includes capitalized internal cost of \$13.3 million, \$8.1 million and \$6.3 million, respectively.

Our development costs included \$1.208 billion, \$671 million and \$333 million in 2006, 2005 and 2004, respectively, related to properties carried as proved undeveloped locations in the prior year's reserve reports. Included in our reserve reports as of December 31, 2006 are estimated future development costs of \$6.2 billion related to the development of proved undeveloped reserves (\$2.7 billion in 2007, \$1.4 billion in 2008, \$0.8 billion in 2009 and \$1.3 billion in 2010 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.

A summary of our exploration and development, acquisition and divestiture activities in 2006 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	1,884	621	\$1,529,917	\$325,733	\$ 206,575	\$ 223,642	\$ (73)	\$2,285,794
Fort Worth Barnett Shale	244	187	427,872	5,461	1,153,502	470,773	—	2,057,608
Appalachian Basin	319	272	171,241	19,611	175,197	21,134	—	387,183
Permian and Delaware Basins	189	92	413,296	44,551	659,144	10,814	(45)	1,127,760
Ark-La-Tex	248	175	380,514	53,697	319,738	55,106	—	809,055
South Texas and Texas Gulf Coast	138	102	375,219	167,497	341,692	573,878	—	1,458,286
Total	<u>3,022</u>	<u>1,449</u>	<u>\$3,298,059</u>	<u>\$616,550</u>	<u>\$2,855,848</u>	<u>\$1,355,347</u>	<u>\$(118)</u>	<u>\$8,125,686</u>

(a) Includes \$180 million of deferred tax adjustments.

Acreage

The following table sets forth as of December 31, 2006 the gross and net acres of both developed and undeveloped oil and natural 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	3,739,724	1,793,900	4,488,205	2,268,007	8,227,929	4,061,907
Fort Worth Barnett Shale	58,706	50,329	189,847	131,346	248,553	181,675
Appalachian Basin	524,348	496,311	3,425,091	3,240,776	3,949,439	3,737,087
Permian and Delaware Basins	326,819	175,101	1,741,527	1,083,636	2,068,346	1,258,737
Ark-La-Tex	201,082	131,296	1,011,252	596,828	1,212,334	728,124
South Texas and Texas Gulf Coast	323,824	201,477	289,533	211,036	613,357	412,513
Total	<u>5,174,503</u>	<u>2,848,414</u>	<u>11,145,455</u>	<u>7,531,629</u>	<u>16,319,958</u>	<u>10,380,043</u>

Marketing

Chesapeake's oil production is generally sold under market sensitive or spot price contracts. The revenue we receive from the sale of natural gas liquids is included in oil sales. 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 natural gas. These purchasers sell the residue gas and natural gas liquids based primarily on spot market prices. Under percentage-of-index contracts, the price per mmbtu we receive for our natural gas is tied to indexes published in *Inside FERC* or *Gas Daily*. Although exact percentages vary daily, as of February 2007, approximately 80% of our natural gas production was sold under short-term contracts at market-sensitive or spot prices.

During 2006, sales to Eagle Energy Partners I, L.P. (Eagle) of \$867 million accounted for 16% of our total revenues (excluding gains (losses) on derivatives). Chesapeake owns approximately 33% 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 (excluding gains (losses) on derivatives) in 2006.

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 the notes to our consolidated financial statements in Item 8.

Drilling

In 2001, Chesapeake formed its 100% owned drilling rig subsidiary, Nomac Drilling Corporation (“Nomac”) with an investment of \$26 million to build and refurbish five drilling rigs. As of December 31, 2006, Chesapeake had invested approximately \$300 million to build or acquire 42 drilling rigs and to initiate the construction of 14 additional rigs. Including 24 rigs sold in 2006 and subsequently leased back to Chesapeake through 2014, the drilling rigs have depth ratings between 4,200 and 23,000 feet and range in drilling horsepower from 575 to 2,000. These drilling rigs are currently operating in Oklahoma, Texas and Appalachia. The company’s drilling rig fleet should reach 81 rigs by mid-year 2007, which would rank Chesapeake as the sixth largest drilling rig contractor in the U.S. Additionally, the company has a \$77 million investment in two private drilling rig contractors, DHS Drilling Company and Mountain Drilling Company, in which Chesapeake’s equity ownership is approximately 45% and 49%, respectively. DHS owns 16 rigs and Mountain is operating 4 rigs and has another 4 rigs under construction or on order for delivery in 2007.

Natural Gas Gathering

Chesapeake owns and operates gathering systems in 13 states throughout the Mid-Continent and Appalachian regions. These systems are designed primarily to gather company production for delivery into major intrastate or interstate pipelines and are comprised of approximately 8,000 miles of gathering lines, treating facilities and processing facilities which provide service to approximately 9,750 wells.

Trucking

In 2006, Chesapeake expanded its service operations by acquiring two privately-owned oilfield trucking service companies. Our trucking business is utilized primarily to transport drilling rigs for both Chesapeake and third parties. As of December 31, 2006, our fleet includes 174 trucks which mainly service the Mid-Continent and Appalachian regions.

Compression

During the past few years Chesapeake has expanded its compression business. As of December 31, 2006, we operated 732 compressors, including wellhead and system compressors. Our compression business exists to facilitate the transportation of our natural gas production.

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.

Regulation

General. All of our operations are conducted onshore in the United States. The U.S. oil and natural 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.

Regulation of Oil and Natural Gas Operations. Our exploration and production operations are subject to various types of regulation at the U.S. federal, state and local levels, although very few of our oil and natural gas leases are located on federal lands. 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 natural gas properties. In this regard, some states, such as Oklahoma and Arkansas, allow the forced pooling or integration of tracts to facilitate exploration, while other states, such as Texas and New Mexico, 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 natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these regulations is to limit the amount of oil and natural gas we can produce and to limit the number of wells or the locations at which we can drill.

Chesapeake operates a number of natural gas gathering systems. The U.S. Department of Transportation and certain state agencies regulate the safety and operating aspects of the transportation and storage activities of these facilities. There is currently no price regulation of the company's sales of oil, natural gas liquids and natural gas, although, governmental agencies may elect in the future to regulate certain sales.

We do not anticipate that compliance with existing laws and regulations governing exploration, production and natural gas gathering 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, constructing, drilling, operating and abandoning wells and related surface facilities. 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 natural 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 \$1.252 billion in 2006 compared to income tax expense of \$545.1 million in 2005 and \$289.8 million in 2004. Of the \$706.9 million increase in 2006, \$643.1 million was the result of the increase in net income before taxes and \$63.8 million was the result of an increase in the effective tax rate. Our effective income tax rate was 38.5% in 2006 compared to 36.5% in 2005 and 36% in 2004. The increase in 2006 reflected the impact state income taxes and permanent differences had on our overall effective rate along with the effect of a Texas tax law change. In May 2006, Texas eliminated the existing franchise tax and replaced it with a new income-based margin tax. The new tax is effective for tax returns due on or after January 1, 2008 for our 2007 business activity. We recorded a \$15 million liability in 2006 to reflect the impact that this change had on our liability for additional deferred income taxes at the date of enactment. We expect our effective income tax rate to be 38% in 2007.

At December 31, 2006, Chesapeake had federal income tax net operating loss (NOL) carryforwards of approximately \$631.1 million. We also had approximately \$3.6 million of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income and approximately \$15.9 million of percentage depletion carryforwards. The NOL carryforwards expire from 2011 through 2026. 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, 2006 and any related limitations:

	Net Operating Losses		
	Total	Limited	Annual Limitation
	(\$ in thousands)		
Net operating loss	\$631,123	\$30,570	\$15,568
AMT net operating loss	\$ 3,565	\$ 3,565	\$ 520

As of December 31, 2006, we do not believe that an ownership change has occurred. 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. Following 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.

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 natural 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 natural gas industry. Nevertheless, we are involved in title disputes from time to time which result in litigation.

Operating Hazards and Insurance

The oil and natural 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, natural 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 natural 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 \$200 million comprehensive general liability umbrella policy and a \$100 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.

Facilities

Chesapeake owns an office complex in Oklahoma City and also owns or leases various field offices in the following locations:

- Arkansas: Searcy
- Illinois: Chicago
- Kansas: Garden City
- Kentucky: Gray, Elkhorn City, Hueysville, Inez and Prestonsburg
- Louisiana: Cheneyville, Goldonna and Shreveport
- New Mexico: Carlsbad, Eunice, Hobbs and Lovington
- New York: Hammondsport
- North Dakota: Dickinson
- Oklahoma: Arkoma, Billings, El Reno, Elk City, Enid, Forgan, Kingfisher, Lindsay, Oklahoma City, Waynoka, Weatherford, Wilburton, Woodward and Sayre
- Pennsylvania: Mt. Morris
- Tennessee: Egan
- Texas: Borger, Bryan, Cleburne, College Station, Dumas, Ft. Worth, Garrison, Marshall, Midland, Ozona, Pecos, Tyler, Victoria and Zapata
- West Virginia: Branchland, Buckhannon, Cedar Grove, Charleston, Clendenin, Kermit, Shrewsbury and Tad

Employees

Chesapeake had approximately 4,900 employees as of December 31, 2006, which includes 1,625 employed by our service operations companies. As a result of the CNR acquisition, approximately 135 of our employees were covered by a collective bargaining agreement with the United Steel Workers of America ("USWA") which expired effective December 1, 2006. We have continued to operate under the terms of the collective bargaining agreement while we are negotiating with the USWA. Contract negotiations began in October 2006 and are being mediated by the National Mediation Board. There have been no strikes, work stoppages, pickets or slow-downs since the expiration of the contract, although no assurances can be given that such actions will not occur.

Glossary of Oil and Natural Gas Terms

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

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet of natural 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 natural gas well which produces oil and natural 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 natural 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 natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Exploratory Well. A well drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural 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 natural gas equivalent.

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

Mmbtu. One million btus.

Mmcf. One million cubic feet.

Mmcf. One million cubic feet of natural 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 natural 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 natural 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 natural 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.

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.

Reserve Replacement. Calculated by dividing the sum of reserve additions from all sources (revisions, extensions, discoveries and other additions and acquisitions) by the actual production for the corresponding period. The values for these reserve additions are derived directly from the proved reserves table located in Note 11 of the notes to our consolidated financial statements. In calculating reserve replacement, we do not use unproved reserve quantities or proved reserve additions attributable to less than wholly owned consolidated entities or investments accounted for using the equity method. 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. It should be noted that the reserve replacement ratio is a statistical indicator that has limitations. As an annual measure, the ratio is limited because it typically varies widely based on the extent and timing of new discoveries and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not imbed the cost or timing of future production of new reserves, it cannot be used as a measure of value creation.

Royalty Interest. An interest in an oil and natural gas property entitling the owner to a share of oil or natural 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 natural 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 natural 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 1A. Risk Factors

Oil and natural 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 natural 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 natural gas have been volatile and they are likely to continue to be volatile. Wide fluctuations in oil and natural 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 natural gas;
- weather conditions;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the proximity and capacity of natural gas pipelines and other transportation facilities;
- 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
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. Declines in oil and natural gas prices would not only reduce revenue, but could reduce the amount of oil and natural 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 natural gas prices do not necessarily move in tandem. Because approximately 93% of our reserves at December 31, 2006 were 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, 2006, we had long-term indebtedness of approximately \$7.4 billion, with \$178 million of outstanding borrowings drawn under our revolving bank credit facility. Our long-term indebtedness represented 40% of our total book capitalization at December 31, 2006. As of February 23, 2007, we had approximately \$1.033 billion outstanding under our revolving bank credit facility.

Our level of indebtedness and preferred stock 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 pay dividends on our preferred stock 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, or issue additional series of preferred stock in order to make future acquisitions or to develop our properties. A higher level of indebtedness and/or additional preferred stock increases the risk that we may default on our 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 natural 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 natural gas, and our success in developing and producing new reserves. If revenues were to decrease as a result of lower oil and natural 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 fund our capital expenditure budget, we may not be able to access additional bank debt, debt or 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 natural 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 38% of our total estimated proved reserves (by volume) at December 31, 2006 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 25% from 2007 to 2008. 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 natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural 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 natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural 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 natural 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, 2006, approximately 38% 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 the reserves, including approximately \$2.7 billion in 2007. 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 natural 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, 2006 present value is based on weighted average oil and natural gas wellhead prices of \$56.25 per barrel of oil and \$5.41 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 natural 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 natural 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 natural 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 growth during the past few years is due in large 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 natural 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. As a result of these factors, the purchase price we pay to acquire oil and natural gas properties may exceed the value we realize.

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. When we make entity acquisitions, we may have transferee liability that is not fully indemnified. Our acquisition of Columbia Natural Resources, LLC (CNR) in November 2005 was made subject to claims which are covered in part by the indemnification of a prior owner, NiSource Inc. NiSource and Chesapeake are co-defendants in a class action lawsuit brought by royalty owners in West Virginia in which the jury returned a verdict in January 2007 awarding plaintiffs \$404 million, consisting of \$134 million in compensatory damages and \$270 million in punitive damages. Although Chesapeake believes its share of damages that might ultimately be awarded in this case will not have a material adverse effect on its results of operations, financial condition or liquidity as a result of the NiSource indemnity and post-trial remedies that may be available, Chesapeake is a defendant in other cases involving acquired companies where it may have no, or only limited, indemnification rights. In any such actions we could incur significant liability.

As new owners, we may not effectively consolidate and integrate acquired operations, particularly when we make significant acquisitions outside our historical operating areas.

Significant acquisitions present operational and administrative challenges that may prove more difficult than anticipated. The failure to consolidate functions and integrate procedures, personnel and operations in an effective and timely manner may adversely affect our business and results of operations, at least temporarily. 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. To the extent that we acquire properties substantially different from the properties in our primary operating areas 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 natural 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:

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

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 natural 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 natural 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 natural gas at that date, adjusted for the impact of derivatives accounted for as cash flow hedges. A significant decline in oil and natural 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 ceiling test calculation as of December 31, 2006 indicated an impairment of our oil and natural gas properties of approximately \$500 million, net of income tax. However, natural gas prices subsequent to December 31, 2006 have improved sufficiently to eliminate this calculated impairment. As a result, we were not required to record a write-down of our oil and natural gas properties under the full-cost method of accounting.

Our hedging activities may reduce the realized prices received for our oil and natural 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 natural gas, we enter into oil and natural 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 natural gas revenues in the future. The fair value of our oil and natural gas derivative instruments outstanding as of December 31, 2006 was an asset of approximately \$344.9 billion. 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.

All but two of our commodity price risk management counterparties require us to provide assurances of performance in the event that the counterparties' mark-to-market exposure to us exceeds certain levels. Most of these arrangements allow us to minimize the potential liquidity impact of significant mark-to-market fluctuations by making collateral allocations from our revolving bank credit facility or directly pledging oil and natural gas properties, rather than posting cash or letters of credit with the counterparties. Future collateral requirements are uncertain, however, and will depend on the arrangements with our counterparties and highly volatile natural gas and oil prices.

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

Our revolving bank credit facility limits our borrowings to the lesser of the borrowing base and the total commitments (currently both are \$2.5 billion). The borrowing base is determined periodically at the discretion of the banks and is based in part on oil and natural gas prices. Additionally, some of our indentures contain covenants limiting our ability to incur indebtedness in addition to that incurred under our revolving 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 natural 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 the relevant indentures) to our adjusted consolidated interest expense over a trailing twelve-month period. Currently, we are permitted to incur significant additional indebtedness under both of these debt incurrence tests. Lower oil and natural 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 natural gas drilling and producing operations can be hazardous and may expose us to environmental liabilities.

Oil and natural 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 occurs, 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 administrative, civil and criminal penalties; and
- injunctions resulting in limitation or suspension of operations.

There is inherent risk of incurring significant environmental costs and liabilities in our exploration and production operations due to our generation, handling, and disposal of materials, including wastes and petroleum hydrocarbons. We may incur joint and several, strict liability under applicable U.S. federal and state environmental laws in connection with releases of petroleum hydrocarbons and wastes on, under or from our leased or owned properties, some of which have been used for oil and natural gas exploration and production activities for a number of years, often by third parties not under our control. While we may 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.

In addition, in response to studies suggesting that emissions of certain gases may be contributing to warming of the earth's atmosphere, many states are beginning to consider initiatives to track and record these gases, generally referred to as "greenhouse gases," with several states having already adopted regulatory initiatives and one state, California, having adopted legislation aimed at reducing emissions of greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas, are included among the types of gases targeted by greenhouse gas initiatives and laws. This movement is in its infancy but regulatory initiatives or legislation placing restrictions on emissions of methane or carbon dioxide that may be imposed in various states of the United States could adversely affect our operations and the demand for our products.

ITEM 1B. *Unresolved Staff Comments*

None.

ITEM 2. *Properties*

Information regarding our properties is included in Item 1 and in Note 11 of the notes to our consolidated financial statements included in Item 8 of this report.

ITEM 3. *Legal Proceedings*

We are involved in various disputes incidental to our business operations, including claims from royalty owners regarding volume measurements, post-production costs and prices for royalty calculations. In *Tawney, et al. v. Columbia Natural Resources, Inc.*, Chesapeake's wholly owned subsidiary Chesapeake Appalachia, L.L.C., formerly known as Columbia Natural Resources, LLC (CNR), is a defendant in a class action lawsuit in the Circuit Court of Roane County, West Virginia filed in 2003 by royalty owners. The plaintiffs allege that CNR underpaid royalties by improperly deducting post-production costs, failing to pay royalty on total volumes of natural gas produced and not paying a fair value for the natural gas produced from their leases. The plaintiff class consists of West Virginia royalty owners receiving royalties after July 31, 1990 from CNR. Chesapeake acquired CNR in November 2005, and its seller acquired CNR in 2003 from NiSource Inc. NiSource, a co-defendant in the case, has managed the litigation and indemnified Chesapeake against underpayment claims based on the use of fixed prices for natural gas production sold under certain forward sale contracts and other claims with respect to CNR's operations prior to September 2003.

On January 27, 2007, the Circuit Court jury returned a verdict against the defendants of \$404 million, consisting of \$134 million in compensatory damages and \$270 million in punitive damages. Most of the damages awarded by the jury relate to issues not yet addressed by the West Virginia Supreme Court of Appeals, although

in June 2006 that Court ruled against the defendants on two certified questions regarding the deductibility of post-production expenses. The jury found fraud with respect to the sales prices used to calculate royalty payments and with respect to the failure of CNR to disclose post-production deductions.

Chesapeake and NiSource maintain CNR acted in good faith and paid royalties in accordance with lease terms and West Virginia law, and they intend to appeal any adverse judgment in the case. Chesapeake and NiSource have filed a joint motion for post-trial review of punitive damages to be heard on March 5, 2007. Chesapeake has established an accrual for amounts it believes will not be indemnified. Should a final nonappealable judgment be entered, Chesapeake believes its share of damages will not have a material adverse effect on its results of operations, financial condition or liquidity.

Chesapeake is subject to other legal proceedings and claims which arise in the ordinary course of business. In our opinion, the final resolution of these proceedings and claims will not have a material effect on the company.

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, 2006:		
Fourth Quarter	\$34.27	\$27.90
Third Quarter	33.76	28.06
Second Quarter	33.79	26.81
First Quarter	35.57	27.75
Year ended December 31, 2005:		
Fourth Quarter	\$40.20	\$26.59
Third Quarter	38.98	22.90
Second Quarter	24.00	17.74
First Quarter	23.65	15.06

At February 23, 2007, there were 1,522 holders of record of our common stock and approximately 300,000 beneficial owners.

Dividends

The following table sets forth the amount of dividends per share declared on Chesapeake common stock during 2006 and 2005:

	2006	2005
Fourth Quarter	\$0.060	\$0.050
Third Quarter	0.060	0.050
Second Quarter	0.060	0.050
First Quarter	0.050	0.045

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.

Several of 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, 2006, our coverage ratio for purposes of the debt incurrence test under the relevant indentures was 7.13 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 by the second debt incurrence test in these indentures, by more than \$1.1 billion.

The following table presents information about repurchases of our common stock during the three months ended December 31, 2006:

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, 2006 through October 31, 2006	3,214	\$31.275	—	—
November 1, 2006 through November 30, 2006	1,970	\$34.020	—	—
December 1, 2006 through December 31, 2006	5,235	\$29.864	—	—
Total	<u>10,419</u>	<u>\$31.085</u>	<u>—</u>	<u>—</u>

- (a) Includes 29 shares purchased in the open market for the matching contributions we make to our 401(k) plans, the deemed surrender to the company of 2,536 shares of common stock to pay the exercise price in connection with the exercise of employee stock options and the surrender to the company of 7,854 shares of common stock to pay withholding taxes in connection with the vesting of employee restricted stock.
- (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 the 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, 2006, 2005, 2004, 2003 and 2002. 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 natural gas and increased production from drilling activity, significant acquisitions in recent years also impacted comparability between years. See Notes 11 and 13 of the notes to our consolidated 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,				
	2006	2005	2004	2003	2002
	(\$ in thousands, except per share data)				
Statement of Operations Data:					
Revenues:					
Oil and natural gas sales	\$5,618,894	\$3,272,585	\$1,936,176	\$1,296,822	\$ 568,187
Oil and natural gas marketing sales	1,576,391	1,392,705	773,092	420,610	170,315
Service operations revenue	130,310	—	—	—	—
Total revenues	<u>7,325,595</u>	<u>4,665,290</u>	<u>2,709,268</u>	<u>1,717,432</u>	<u>738,502</u>
Operating costs:					
Production expenses	489,499	316,956	204,821	137,583	98,191
Production taxes	176,440	207,898	103,931	77,893	30,101
General and administrative expenses	139,152	64,272	37,045	23,753	17,618
Oil and natural gas marketing expenses	1,521,848	1,358,003	755,314	410,288	165,736
Service operations expense	67,922	—	—	—	—
Oil and natural gas depreciation, depletion and amortization	1,358,519	894,035	582,137	369,465	221,189
Depreciation and amortization of other assets	104,240	50,966	29,185	16,793	14,009
Employee retirement expense	54,753	—	—	—	—
Provision for legal settlements	—	—	4,500	6,402	—
Total operating costs	<u>3,912,373</u>	<u>2,892,130</u>	<u>1,716,933</u>	<u>1,042,177</u>	<u>546,844</u>
Income from operations	<u>3,413,222</u>	<u>1,773,160</u>	<u>992,335</u>	<u>675,255</u>	<u>191,658</u>
Other income (expense):					
Interest and other income	25,463	10,452	4,476	2,827	7,340
Interest expense	(300,722)	(219,800)	(167,328)	(154,356)	(112,031)
Gain on sale of investment	117,396	—	—	—	—
Loss on repurchases or exchanges of Chesapeake senior notes	—	(70,419)	(24,557)	(20,759)	(2,626)
Loss on investment in Seven Seas Petroleum, Inc.	—	—	—	(2,015)	(17,201)
Total other income (expense)	<u>(157,863)</u>	<u>(279,767)</u>	<u>(187,409)</u>	<u>(174,303)</u>	<u>(124,518)</u>
Income before income taxes and cumulative effect of accounting change	<u>3,255,359</u>	<u>1,493,393</u>	<u>804,926</u>	<u>500,952</u>	<u>67,140</u>
Income tax expense (benefit):					
Current	5,000	—	—	5,000	(1,822)
Deferred	1,247,036	545,091	289,771	185,360	28,676
Total income tax expense	<u>1,252,036</u>	<u>545,091</u>	<u>289,771</u>	<u>190,360</u>	<u>26,854</u>
Net income before cumulative effect of accounting change, net of tax	<u>2,003,323</u>	<u>948,302</u>	<u>515,155</u>	<u>310,592</u>	<u>40,286</u>
Cumulative effect of accounting change, net of income taxes of \$1,464,000	—	—	—	2,389	—
Net Income	<u>2,003,323</u>	<u>948,302</u>	<u>515,155</u>	<u>312,981</u>	<u>40,286</u>
Preferred stock dividends	(88,645)	(41,813)	(39,506)	(22,469)	(10,117)
Loss on conversion/exchange of preferred stock	(10,556)	(26,874)	(36,678)	—	—
Net income available to common shareholders	<u>\$ 1,904,122</u>	<u>\$ 879,615</u>	<u>\$ 438,971</u>	<u>\$ 290,512</u>	<u>\$ 30,169</u>
Earnings per common share—basic:					
Income before cumulative effect of accounting change	\$ 4.78	\$ 2.73	\$ 1.73	\$ 1.36	\$ 0.18
Cumulative effect of accounting change	—	—	—	0.02	—
	<u>\$ 4.78</u>	<u>\$ 2.73</u>	<u>\$ 1.73</u>	<u>\$ 1.38</u>	<u>\$ 0.18</u>
Earnings per common share—assuming dilution:					
Income before cumulative effect of accounting change	\$ 4.35	\$ 2.51	\$ 1.53	\$ 1.20	\$ 0.17
Cumulative effect of accounting change	—	—	—	0.01	—
	<u>\$ 4.35</u>	<u>\$ 2.51</u>	<u>\$ 1.53</u>	<u>\$ 1.21</u>	<u>\$ 0.17</u>
Cash dividends declared per common share	<u>\$ 0.23</u>	<u>\$ 0.195</u>	<u>\$ 0.17</u>	<u>\$ 0.135</u>	<u>\$ 0.06</u>

	Years Ended December 31,				
	2006	2005	2004	2003	2002
	(\$ in thousands, except per share data)				
Cash Flow Data:					
Cash provided by operating activities	\$ 4,843,474	\$ 2,406,888	\$ 1,432,274	\$ 938,907	\$ 428,797
Cash used in investing activities	8,942,499	6,921,378	3,381,204	2,077,217	779,745
Cash provided by financing activities	4,041,517	4,567,621	1,915,245	931,254	480,991
Balance Sheet Data (at end of period):					
Total assets	\$24,417,167	\$16,118,462	\$8,244,509	\$4,572,291	\$2,875,608
Long-term debt, net of current maturities	7,375,548	5,489,742	3,075,109	2,057,713	1,651,198
Stockholders' equity	11,251,471	6,174,323	3,162,883	1,732,810	907,875

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 natural gas sales, average sales prices received, other operating income and expenses for the periods indicated:

	Years Ended December 31,		
	2006	2005	2004
Net Production:			
Oil (mbbls)	8,654	7,698	6,764
Natural gas (mmcf)	526,459	422,389	322,009
Natural gas equivalent (mmcfe)	578,383	468,577	362,593
Oil and Natural Gas Sales (\$ in thousands):			
Oil sales	\$ 526,687	\$ 401,845	\$ 260,915
Oil derivatives—realized gains (losses)	(14,875)	(34,132)	(69,267)
Oil derivatives—unrealized gains (losses)	28,459	4,374	3,454
Total oil sales	540,271	372,087	195,102
Natural gas sales	3,343,056	3,231,286	1,789,275
Natural gas derivatives – realized gains (losses)	1,268,528	(367,551)	(85,634)
Natural gas derivatives – unrealized gains (losses)	467,039	36,763	37,433
Total natural gas sales	5,078,623	2,900,498	1,741,074
Total oil and natural gas sales	\$5,618,894	\$3,272,585	\$1,936,176
Average Sales Price (excluding gains (losses) on derivatives):			
Oil (\$ per bbl)	\$ 60.86	\$ 52.20	\$ 38.57
Natural gas (\$ per mcf)	\$ 6.35	\$ 7.65	\$ 5.56
Natural gas equivalent (\$ per mcfe)	\$ 6.69	\$ 7.75	\$ 5.65
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Oil (\$ per bbl)	\$ 59.14	\$ 47.77	\$ 28.33
Natural gas (\$ per mcf)	\$ 8.76	\$ 6.78	\$ 5.29
Natural gas equivalent (\$ per mcfe)	\$ 8.86	\$ 6.90	\$ 5.23
Other Operating Income (a) (\$ in thousands):			
Oil and natural gas marketing	\$ 54,543	\$ 34,702	\$ 17,778
Service operations	\$ 62,388	\$ —	\$ —
Other Operating Income (\$ per mcfe):			
Oil and natural gas marketing	\$ 0.09	\$ 0.07	\$ 0.05
Service operations	\$ 0.11	\$ —	\$ —
Expenses (\$ per mcfe):			
Production expenses	\$ 0.85	\$ 0.68	\$ 0.56
Production taxes (b)	\$ 0.31	\$ 0.44	\$ 0.29
General and administrative expenses	\$ 0.24	\$ 0.14	\$ 0.10
Oil and natural gas depreciation, depletion and amortization	\$ 2.35	\$ 1.91	\$ 1.61
Depreciation and amortization of other assets	\$ 0.18	\$ 0.11	\$ 0.08
Interest expense (c)	\$ 0.52	\$ 0.47	\$ 0.45
Interest Expense (\$ in thousands):			
Interest expense	\$ 300,450	\$ 226,330	\$ 162,781
Interest rate derivatives—realized (gains) losses	1,898	(4,945)	(791)
Interest rate derivatives—unrealized (gains) losses	(1,626)	(1,585)	5,338
Total interest expense	\$ 300,722	\$ 219,800	\$ 167,328
Net Wells Drilled	1,449	816	546
Net Producing Wells as of the End of Period	19,079	16,985	8,058

- (a) Includes revenue and operating costs and excludes depreciation and amortization of other assets.
- (b) Production taxes in 2006 include an \$11.6 million reversal, or \$0.02 per mcfe, of production taxes as a result of the dismissal of certain production tax claims. The \$11.6 million accrual consisted of \$2.1 million in accruals made during 2006 and \$9.5 million in accruals made during 2005. Production taxes in 2004 include a benefit of \$6.8 million, or \$0.02 per mcfe, from 2003 severance tax credits.
- (c) Includes the effects of realized gains (losses) from interest rate derivatives, but excludes the effects of unrealized gains (losses) and is net of amounts capitalized.

We manage our business as three separate segments: an exploration and production segment, a marketing segment and a service operations segment which is comprised of our wholly owned drilling and trucking subsidiaries. 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 2006, 2005 and 2004 and our assets as of December 31, 2006, 2005 and 2004.

Executive Summary

Chesapeake is the third largest independent producer of natural gas in the United States. We own interests in approximately 34,600 producing oil and natural gas wells that are currently producing approximately 1.7 bcfe per day, 92% of which is natural gas. Our strategy is focused on discovering, developing and acquiring onshore natural gas reserves in the U.S. east of the Rocky Mountains. Our most important operating area has historically been in various conventional plays in the *Mid-Continent region* of Oklahoma, Arkansas, southwestern Kansas and the Texas Panhandle. At December 31, 2006, 47% of our estimated proved oil and natural gas reserves were located in the Mid-Continent region. During the past five years, we have also built significant positions in various conventional and unconventional plays in the *Fort Worth Basin* in north-central Texas; the *Appalachian Basin*, principally in West Virginia, eastern Kentucky, eastern Ohio and southern New York; the *Permian and Delaware Basins* of West Texas and eastern New Mexico; the *Ark-La-Tex* area of East Texas and northern Louisiana; and the *South Texas and Texas Gulf Coast regions*. We have established a top-three position in nearly every major shale play in the U.S., including the *Forth Worth Basin Barnett Shale*, the *Arkansas Fayetteville Shale*, the *Appalachian Basin Devonian Shale*, the *southeast Oklahoma Woodford Shale*, the *Delaware Basin Barnett and Woodford Shales*, the *Illinois Basin New Albany Shale* and the *Conasauga, Floyd and Chattanooga Shales* in Alabama.

Oil and natural gas production for 2006 was 578.4 bcfe, an increase of 109.8 bcfe, or 23% over the 468.6 bcfe produced in 2005. We have increased our production for 17 consecutive years and 22 consecutive quarters. During these 22 quarters, Chesapeake's U.S. production has increased 322% for an average compound quarterly growth rate of 6.8% and an average compound annual growth rate of 29.7%.

In addition to increased oil and natural gas production, the prices we received were higher in 2006 than in 2005. On a natural gas equivalent basis, weighted average prices (excluding the effect of unrealized gains or losses on derivatives) were \$8.86 per mcfe in 2006 compared to \$6.90 per mcfe in 2005. The increase in prices resulted in an increase in revenue of \$1.135 billion, and increased production resulted in an increase in revenue of \$757.2 million, for a total increase in revenue of \$1.892 billion (excluding the effect of unrealized gains or losses on derivatives). In each of the operating areas where Chesapeake sells its oil and natural gas, established marketing and transportation infrastructures exist, thereby contributing to relatively high wellhead price realizations for our production.

During 2006, we led the nation in drilling activity with an average utilization of 98 operated rigs and 79 non-operated rigs. Through this drilling activity, we drilled 1,488 (1,243 net) operated wells and participated in another 1,534 (206 net) wells operated by other companies. Our success rate was 99% for operated wells and 98% for non-operated wells. To accelerate the development of our extensive prospect inventory, we have increased our current drilling activity to 132 operated rigs and we anticipate keeping our operated rig count between 130 and 140

rigs during 2007. In 2006, we added approximately 2,000 new employees to support our growth, which increased our total employee base to approximately 4,900 employees at December 31, 2006, and invested \$771 million in leasehold (excluding leasehold acquired through corporate and asset acquisitions) and 3-D seismic data, all of which we consider the building blocks of future value creation.

Chesapeake began 2006 with estimated proved reserves of 7.521 tcf and ended the year with 8.956 tcf, an increase of 1.435 tcf, or 19%. During 2006, we replaced 578.4 bcfe of production with an estimated 2.013 tcf of new proved reserves, for a reserve replacement rate of 348%. Reserve replacement through the drillbit was 1.345 tcf, or 233% of production (including 729 bcfe of positive performance revisions and 212 bcfe of downward revisions resulting from natural gas price declines between December 31, 2005 and December 31, 2006) and 67% of the total increase. Reserve replacement through the acquisition of proved reserves was 668 bcfe, or 115% of production and 33% of the total increase. Our annual decline rate on producing properties is projected to be 25% from 2007 to 2008, 16% from 2008 to 2009, 13% from 2009 to 2010, 11% from 2010 to 2011 and 10% from 2011 to 2012. Our percentage of proved undeveloped reserve additions to total proved reserve additions was approximately 38% in 2006, 36% in 2005 and 56% in 2004. Based on our current drilling schedule and budget, we expect that virtually all of the proved undeveloped reserves added in 2006 will begin producing within the next three to five years. Generally, proved developed reserves are producing at the time they are added or will begin producing within one year.

Chesapeake attributes its strong drilling results and production growth during 2006 (and in this decade) to management's early recognition that oil and natural gas prices were undergoing structural change and its subsequent decision to invest aggressively in the building blocks of value creation in the E&P industry—people, land and seismic. During the past five years, Chesapeake has significantly strengthened its technical capabilities by increasing its land, geoscience and engineering staff to approximately 1,000 employees. Today, the company has approximately 4,900 employees, of which approximately 60% work in the company's E&P operations and 40% work in the company's oilfield service operations.

Since 2000, Chesapeake has invested \$6.6 billion in new leasehold and 3-D seismic acquisitions and now owns what it believes to be one of the largest inventories of onshore leasehold (10.4 million net acres) and 3-D seismic (16.3 million acres) in the U.S. On this leasehold, the company has an estimated 26,000 net drilling locations representing an approximate 10-year inventory of drilling projects.

Chesapeake's direct and indirect drilling rig investments have served as an effective hedge to higher service costs and have also provided competitive advantages in making acquisitions and in developing the company's own leasehold on a more timely and efficient basis. As of December 31, 2006, Chesapeake had invested approximately \$300 million to build or acquire 42 drilling rigs and to begin the construction of 14 additional rigs. During 2006, the company entered into a sale/leaseback transaction to monetize its investment in 24 rigs in exchange for cash proceeds of approximately \$244 million. These rigs are under lease to Chesapeake through 2014 at which time the company has the option to reacquire them. Including the 24 rigs sold and subsequently leased back to Chesapeake, the company's drilling rig fleet should reach 81 rigs by mid-year 2007, which would rank Chesapeake as the sixth largest drilling rig contractor in the U.S. Additionally, the company has a \$77 million investment in two private drilling rig contractors, DHS Drilling Company and Mountain Drilling Company, in which Chesapeake's equity ownership is approximately 45% and 49%, respectively. DHS owns 16 rigs and Mountain is operating 4 rigs and has another 4 rigs under construction or on order for delivery in 2007.

To further hedge its exposure to oilfield service costs and achieve greater operational efficiency, in 2006 Chesapeake invested \$254 million to acquire a 19.9% interest in a privately-held provider of well stimulation and high pressure pumping services with operations currently focused in Texas (principally in the Fort Worth Barnett Shale) and the Rocky Mountains. It also has expansion efforts underway in many other key regions in which Chesapeake operates.

As of December 31, 2006, the company's debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders' equity) was 40% compared to 47% as of December 31, 2005. During 2006, we received net proceeds of \$4.071 billion through issuances of \$575 million of preferred equity, \$1.8 billion of common equity and \$1.8 billion principal amount of senior notes. We used the net proceeds from these offerings primarily to fund the purchase price for acquisitions and to repay outstanding indebtedness under our revolving bank credit facility. As a result of our debt transactions in 2005 and 2006, we have extended the average maturity of our long-term debt to over nine years with an average interest rate of approximately 6.5%.

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 at some point 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 our drilling, land and seismic capital expenditures in 2007 to exceed our cash flow from operations. Any additional funds required will be provided through additional borrowings under our bank credit facility. Our budget for drilling, land and seismic activities during 2007 is currently between \$4.7 billion and \$4.9 billion. We believe this level of exploration and development will be sufficient to increase our proved oil and natural gas reserves in 2007 and increase our total production by 14% to 18% (inclusive of acquisitions completed or scheduled to close in 2007 through the filing date of this report but without regard to any additional acquisitions that may be completed in 2007). However, 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.

Cash provided by operating activities was \$4.843 billion in 2006, compared to \$2.407 billion in 2005 and \$1.432 billion in 2004. The \$2.436 billion increase from 2005 to 2006 and the \$975 million increase from 2004 to 2005 were primarily due to higher realized prices and higher volumes of oil and natural gas production. We expect that 2007 production volumes will be higher than in 2006 and that cash provided by operating activities in 2007 will exceed 2006 levels. While a decline in natural gas prices in 2007 would affect the amount of cash flow that would be generated from operations, we currently have oil swaps in place covering 59% of our expected oil production in 2007 at an average NYMEX price of \$71.90 per barrel of oil and natural gas swaps in place covering 48% of our expected natural gas production in 2007 at an average NYMEX price of \$8.63 per mcf, along with natural gas collars covering 10% of our anticipated natural gas production for 2007 with an average NYMEX floor of \$6.88 per mcf and an average NYMEX ceiling of \$8.41 per mcf. Additionally, we have written call options covering 10% of our 2007 natural gas production at a weighted average price of \$9.56. This level of hedging provides certainty of the cash flow we will receive for a substantial portion of our 2007 production. Depending on changes in oil and natural 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. All but three of our commodity price risk management counterparties require us to provide assurances of performance in the event that the counterparties' mark-to-market exposure to us exceeds certain levels. Most of these arrangements allow us to minimize the potential liquidity impact of significant mark-to-market fluctuations by making collateral allocations from our bank credit facility or directly pledging oil and natural gas properties, rather than posting cash or letters of credit with the counterparties. As of December 31, 2006, we had outstanding collateral allocations and pledges of oil and natural gas properties, with respect to commodity price risk management transactions but were not required to post any collateral with our counterparties through letters of credit issued under our bank credit facility. As of

February 23, 2007, we had outstanding transactions with fifteen counterparties, eight of which hold collateral allocations from our bank facility or liens against certain oil and natural gas properties under our secured hedging facilities, and two of which do not require us to provide security for our risk management transactions. As of February 23, 2007, we were not required to post cash or letters of credit with the remaining five counterparties. Future collateral requirements are uncertain and will depend on the arrangements with our counterparties and highly volatile natural gas and oil prices.

A significant source of liquidity is our \$2.5 billion syndicated revolving bank credit facility which matures in February 2011. At February 23, 2007, there was \$1.464 billion 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 \$8.370 billion and repaid \$8.264 billion in 2006, we borrowed \$5.682 billion and repaid \$5.669 billion in 2005 and we borrowed \$2.160 billion and repaid \$2.101 billion in 2004 under our bank credit facility. We incurred \$5.1 million, \$4.7 million and \$2.2 million of financing costs related to our revolving bank credit facility in 2006, 2005 and 2004, respectively, as a result of amendments to the credit facility agreement. During 2005, we repaid the remaining credit facility balance of \$96.1 million assumed in our 2005 acquisition of Columbia Natural Resources, LLC.

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, debt service and general and administrative expenses, our capital expenditure budget, our short-term contractual obligations and dividend payments at current levels for the foreseeable future.

The public and institutional markets have been our principal source of long-term financing for 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 to finance 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 1A.

The following table reflects the proceeds from sales of securities we issued in 2006, 2005 and 2004 (\$ in millions):

	2006		2005		2004	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
Unsecured senior notes guaranteed by subsidiaries	\$1,799.5	\$1,754.8	\$2,300.0	\$2,251.3	\$1,200.0	\$1,166.0
Contingent convertible unsecured senior notes	—	—	690.0	673.3	—	—
Convertible preferred stock	575.0	557.6	1,380.0	1,341.5	313.3	304.9
Common stock	1,799.7	1,759.0	1,024.6	985.8	650.0	624.2
Total	<u>\$4,174.2</u>	<u>\$4,071.4</u>	<u>\$5,394.6</u>	<u>\$5,251.9</u>	<u>\$2,163.3</u>	<u>\$2,095.1</u>

We qualify as a "well-known seasoned issuer" (WKSI), as defined in Rule 405 of the Securities Act of 1933, and therefore we may utilize automatic shelf registration to register future debt and equity issuances with the Securities and Exchange Commission. A prospectus supplement will be prepared at the time of an offering and will contain a description of the security issued, the plan of distribution and other information.

We paid dividends on our common stock of \$87.0 million, \$60.5 million and \$38.9 million in 2006, 2005 and 2004, respectively, and we paid dividends on our preferred stock of \$88.4 million, \$31.5 million and \$40.9 million in 2006, 2005 and 2004, respectively. We received \$73.2 million, \$21.6 million and \$12.0 million from the exercise of employee and director stock options and warrants in 2006, 2005 and 2004, respectively. We paid

\$86.2 million and \$4.0 million to purchase treasury stock in 2006 and 2005. Of these amounts, \$11.1 million and \$4.0 million were used to fund our matching contribution to our 401(k) plans in 2006 and 2005, respectively. The remaining \$75.1 million in 2006 was used to purchase shares of common stock to be used upon the exercise of stock options under certain stock option plans. There were no treasury stock purchases made in 2004.

In 2006 and 2005, we paid \$86.9 million and \$11.6 million to settle a portion of the derivative liabilities assumed in our 2005 acquisition of Columbia Natural Resources, LLC.

Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists increased by \$70.0 million, \$61.2 million and \$88.3 million in 2006, 2005 and 2004, respectively. All disbursements are funded on the day they are presented to our bank using available cash on hand or draws on our revolving bank credit facility.

Historically, we have used significant funds to redeem or purchase and retire outstanding senior notes issued by Chesapeake, although we had no such transactions in 2006. The following table shows our redemption, purchases and exchanges of senior notes for 2005 and 2004 (\$ in millions):

	Senior Notes Activity				
	Retired	Premium	Other (a)	Issued	Cash Paid
For the Year Ended December 31, 2005:					
8.375% Senior Notes due 2008	\$ 19.0	\$ 1.2	\$ —	\$ —	\$ 20.2
8.125% Senior Notes due 2011	245.4	17.3	0.7	—	263.4
9.0% Senior Notes due 2012	300.0	41.4	0.8	—	342.2
	<u>\$564.4</u>	<u>\$59.9</u>	<u>\$ 1.5</u>	<u>\$ —</u>	<u>\$625.8</u>
For the Year Ended December 31, 2004:					
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 (b)	482.8	—	62.1	(534.2)	10.7
	<u>\$720.0</u>	<u>\$16.3</u>	<u>\$62.6</u>	<u>\$(534.2)</u>	<u>\$264.7</u>

- (a) 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.
 (b) We issued \$63.7 million of our 7.75% Senior Notes and \$470.5 million of our 6.875% Senior Notes.

Our accounts receivable are primarily from purchasers of oil and natural gas (\$617.8 million at December 31, 2006) and exploration and production companies which own interests in properties we operate (\$135.3 million at December 31, 2006). 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.

Investing Transactions

Cash used in investing activities increased to \$8.942 billion in 2006, compared to \$6.921 billion in 2005 and \$3.381 billion in 2004. The following table shows our capital expenditures during these years (\$ in millions):

	2006	2005	2004
Oil and Natural Gas Investing Activities:			
Acquisitions of oil and natural gas companies and proved properties, net of cash acquired	\$1,104.2	\$2,759.1	\$1,484.2
Acquisition of unproved properties	2,855.8	1,375.7	570.5
Exploration and development of oil and natural gas properties	3,008.7	1,793.4	960.1
Leasehold acquisitions	616.6	290.9	110.5
Geological and geophysical costs	154.0	70.9	55.6
Other oil and natural gas activities	(0.1)	(2.4)	(1.9)
Total oil and natural gas investing activities	7,739.2	6,287.6	3,179.0
Other Investing Activities:			
Additions to buildings and other fixed assets	593.7	417.5	126.7
Additions to drilling rig equipment	392.7	66.8	23.1
Proceeds from sale of drilling rigs and equipment	(243.6)	—	—
Additions to investments	554.6	135.0	37.0
Proceeds from sale of investment in Pioneer Drilling Company	(158.9)	—	—
Acquisition of trucking company, net of cash acquired	45.2	—	—
Deposits for acquisitions	21.7	35.0	16.3
Sale of non-oil and natural gas investments	(1.9)	(20.5)	(0.9)
Other	(0.2)	—	—
Total other investing activities	1,203.3	633.8	202.2
Total cash used in (provided by) investing activities	\$8,942.5	\$6,921.4	\$3,381.2

In 2006, we expanded our service operations through a number of acquisitions. In January 2006, we acquired a privately-owned Oklahoma-based oilfield trucking service company for \$47.5 million. In February 2006, we acquired 13 drilling rigs and related assets through our wholly owned subsidiary, Nomac Drilling Corporation, from Martex Drilling Company, L.L.P., a privately-owned drilling contractor with operations in East Texas and North Louisiana, for approximately \$150 million. In July 2006, we acquired 15 rigs and related trucking assets from a drilling contractor in the Appalachian Basin for approximately \$70 million in cash.

In February 2006, we sold our investment in publicly-traded Pioneer Drilling Company ("Pioneer") common stock, realizing proceeds of \$158.9 million and a gain of \$117.4 million. We owned 17% of the common stock of Pioneer, which we began acquiring in 2003.

In August 2006, we invested \$254 million to acquire a 19.9% interest in a privately-held provider of well stimulation and high pressure pumping services, with operations currently focused in Texas (principally in the Fort Worth Barnett Shale) and the Rocky Mountains. In September 2006, we acquired 32% of the outstanding common stock of Chaparral Energy, Inc. for \$240 million in cash and 1,375,989 newly issued shares of our common stock valued at \$40 million. Chaparral is a privately-held independent oil and natural gas company headquartered in Oklahoma City, Oklahoma.

Financing Transactions

During 2005 and 2006, we took several steps to improve our capital structure. These transactions enabled us to extend our average maturity of long-term debt to over nine years with an average interest rate of approximately 6.5%. Maintaining a debt-to-total-capitalization ratio below 50% and reducing debt per mcfe of proved reserves remain key goals of our business strategy.

We completed the following significant financing transactions in 2006:

First Quarter 2006

- Amended and restated our revolving bank credit facility, increasing the commitments to \$2.0 billion and extending the maturity date to February 2011.
- Issued an additional \$500 million of our 6.5% Senior Notes due 2017 in a private placement and used the proceeds of approximately \$487 million to repay outstanding borrowings under our revolving bank credit facility incurred primarily to fund our recent acquisitions.

Second Quarter 2006

- Exchanged 83,245 shares of our 4.125% cumulative convertible preferred stock, representing 96.4% or \$83.2 million of the aggregate liquidation value of the shares outstanding, for 5.2 million shares of our common stock pursuant to a tender offer.
- Exchanged 804,048 shares of our 5.0% (Series 2003) cumulative convertible preferred stock, representing 95.4% or \$80.4 million of the aggregate liquidation value of the shares outstanding, for 5.0 million shares of our common stock pursuant to a tender offer.
- Completed public offerings of \$500 million of 7.625% Senior Notes due 2013, 2.0 million shares of 6.25% mandatory convertible preferred stock having a liquidation preference of \$250 per share, and 25 million shares of common stock at \$29.05 per share. Net proceeds of approximately \$1.666 billion were used to fund acquisitions, to repay borrowings under our revolving bank credit facility and for general corporate purposes.

Third Quarter 2006

- Increased the commitments under our revolving bank credit facility to \$2.5 billion.
- Issued 3.75 million shares of common stock at \$29.05 per share and 300,000 shares of our 6.25% mandatory convertible preferred stock having a liquidation preference of \$250 per share upon the exercise of the underwriters' options to purchase the additional shares pursuant to the June 2006 public offerings of our common stock and 6.25% preferred stock. Net proceeds of approximately \$177.6 million were used to repay borrowings under our revolving bank credit facility.

Fourth Quarter 2006

- Completed a public offering on December 5, 2006 of €600 million of 6.25% Euro-denominated Senior Notes due 2017 (\$799.5 million based on the dollar/euro exchange rate of \$1.3325 to €1.00). Net proceeds of approximately €589.6 million (or approximately \$785.7 million) were used to repay outstanding borrowings under our revolving bank credit facility.
- Completed a public offering of 30 million shares of common stock at \$32.15 per share. Net proceeds of approximately \$955.3 million were used to repay outstanding borrowings under our revolving bank credit facility.

Contractual Obligations

We currently have a \$2.5 billion syndicated revolving bank credit facility which matures in February 2011. Commitments under the credit facility were increased from \$1.25 billion to \$2.0 billion in February 2006 and to \$2.5 billion in September 2006. As of December 31, 2006, we had \$178.0 million in outstanding borrowings under this facility and had utilized \$6.2 million of the facility for various letters of credit. Borrowings under the facility are collateralized by certain producing oil and natural 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 from 0.875% to 1.50% per annum 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 a commitment fee that also varies according to our senior unsecured long-term debt ratings, from 0.125% to 0.30% per annum. Currently the commitment fee is 0.25% per annum. 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, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.65 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.5 to 1. As defined by the credit facility, our indebtedness to total capitalization ratio was 0.40 to 1 and our indebtedness to EBITDA ratio was 1.64 to 1 at December 31, 2006. 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 (\$50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures which could in turn result in the acceleration of a significant portion 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 \$75 million.

We have three secured hedging facilities maturing in 2011, each of which permits us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to a maximum value. Outstanding transactions under each facility are collateralized by certain of our oil and natural gas properties that do not secure any of our other obligations. The hedging facilities are subject to a 1% per annum exposure fee, which is assessed quarterly on the average of the daily negative fair market value amounts, if any, during the quarter. The hedging facilities contain the standard representations and default provisions that are typical of such agreements. The agreements also contain various restrictive provisions which govern the aggregate oil and natural gas production volumes that we are permitted to hedge under all of our agreements at any one time. The maximum permitted value of transactions under each facility and the fair market values of outstanding transactions are shown below.

	Secured Hedging Facilities		
	#1	#2	#3
	(\$ in thousands)		
Maximum permitted value of transactions under facility	\$750,000	\$500,000	\$500,000
Fair market value of outstanding transactions, as of			
December 31, 2006	\$ 34,403	\$ 59,639	\$ —
Fair market value of outstanding transactions, as of			
February 23, 2007	\$ 26,063	\$ 16,027	\$ 29,243

Two of our subsidiaries, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., are the borrowers under our revolving bank credit facility and Chesapeake Exploration Limited Partnership is the named party to our hedging facilities. The facilities are guaranteed by Chesapeake and all its other wholly owned subsidiaries except minor subsidiaries. Our revolving bank credit facility and secured hedging facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates and commitment fees in our bank credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, the bank facility and the secured hedging facilities do not 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, 2006, senior notes represented approximately \$7.2 billion of our long-term debt and consisted of the following (\$ in thousands):

7.5% Senior Notes due 2013	\$ 363,823
7.625% Senior Notes due 2013	500,000
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
6.625% Senior Notes due 2016	600,000
6.875% Senior Notes due 2016	670,437
6.5% Senior Notes due 2017	1,100,000
6.25% Euro-denominated Senior Notes due 2017 (a)	791,820
6.25% Senior Notes due 2018	600,000
6.875% Senior Notes due 2020	500,000
2.75% Contingent Convertible Senior Notes due 2035	690,000
Discount on senior notes	(101,935)
Discount for interest rate derivatives	(17,005)
	<u>\$7,197,548</u>

(a) The principal amount shown is based on the dollar/euro exchange rate of \$1.3197 to €1.00 as of December 31, 2006. See Note 10 of our financial statements for information on our related cross currency swap.

No scheduled principal payments are required under our senior notes until 2013, when \$863.8 million is due. The holders of the 2.75% Contingent Convertible Senior Notes due 2035 may require us to repurchase all or a portion of these notes on November 15, 2015, 2020, 2025 and 2030 at 100% of the principal amount of these notes.

As of December 31, 2006 and currently, debt ratings for the senior notes are Ba2 by Moody's Investor Service (stable outlook), BB by Standard & Poor's Ratings Services (positive outlook) and BB by Fitch Ratings (stable outlook).

Our senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior indebtedness and rank senior in right of payment with all of our future subordinated indebtedness. All of our wholly owned subsidiaries, except minor subsidiaries, fully and unconditionally guarantee the notes jointly and severally on an unsecured basis. Senior notes issued before July 2005 are governed by indentures containing covenants that limit 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; enter into sale-leaseback transactions; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. Senior notes issued after June 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries' ability to incur certain secured indebtedness; enter into sale-leaseback transactions; 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, 2006, we estimate that secured commercial bank indebtedness of approximately \$3.3 billion could have been incurred under the most restrictive indenture covenant.

The table below summarizes our contractual obligations as of December 31, 2006 (\$ in thousands):

Contractual Obligations	Payments Due By Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 years
Long-term debt obligations	\$7,494,488	\$ —	\$ —	\$178,000	\$7,316,488
Capital lease obligations	5,834	2,491	2,905	438	—
Operating lease obligations	281,974	40,033	77,013	69,665	95,263
Purchase obligations (a)	1,068,387	470,182	308,822	68,922	220,461
Standby letters of credit	6,889	6,889	—	—	—
Total contractual cash obligations	<u>\$8,857,572</u>	<u>\$519,595</u>	<u>\$388,740</u>	<u>\$317,025</u>	<u>\$7,632,212</u>

(a) See Note 4 of the notes to our consolidated financial statements for a description of transportation and drilling contract commitments.

Hedging Activities

Oil and Natural Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and natural 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 meeting. We believe we have sufficient internal controls to prevent unauthorized hedging. As of December 31, 2006, our oil and natural 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 natural 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 activities are dynamic.

Mark-to-market positions under oil and natural 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 natural gas derivatives resulted in a net increase in oil and natural gas sales of \$1.254 billion, or \$2.17, per mcf in 2006, a net decrease of \$401.7 million, or \$0.86, per mcf in 2005 and a net decrease of \$154.9 million, or \$0.43, per mcf in 2004. Oil and natural gas sales also include changes in the fair value of oil and natural 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 natural gas sales in 2006, 2005 and 2004 were \$495.5 million, \$41.1 million and \$40.9 million, respectively. Included in these unrealized gains (losses) are gains (losses) on ineffectiveness of cash flow hedges of \$311.1 million in 2006, (\$76.3) million in 2005 and (\$8.2) million in 2004.

Changes in the fair value of oil and natural 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 and are transferred to earnings in the month of related production. These unrealized gains (losses), net of related tax effects, totaled \$545.9 million,

(\$270.7) million and (\$4.4) million as of December 31, 2006, 2005 and 2004, respectively. Based upon the market prices at December 31, 2006, we expect to transfer to earnings approximately \$282.5 million of the net gain included in the balance of accumulated other comprehensive income during the next 12 months. A detailed explanation of accounting for oil and natural gas derivatives under SFAS 133 appears under "Application of Critical Accounting Policies—Hedging" elsewhere in this Item 7.

The estimated fair values of our oil and natural gas derivative instruments as of December 31, 2006 and 2005 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	December 31,	
	2006	2005
	(\$ in thousands)	
Derivative assets (liabilities):		
Fixed-price natural gas swaps	\$ 1,075	\$(1,081,323)
Natural gas basis protection swaps	186,970	307,308
Fixed-price natural gas cap-swaps	121,866	(161,056)
Fixed-price natural gas counter-swaps	(5,455)	37,785
Natural gas call options (a)	(4,873)	(21,461)
Fixed-price natural gas collars	(6,922)	(9,374)
Floating-price natural gas swaps	—	2,607
Fixed-price oil swaps	28,149	(16,936)
Fixed-price oil cap-swaps	24,057	(3,364)
Estimated fair value	<u>\$ 344,867</u>	<u>\$ (945,814)</u>

(a) After adjusting for \$15.4 million and \$23.0 million of unrealized premiums, the cumulative unrealized gain related to these call options as of December 31, 2006 and 2005 was \$10.5 million and \$1.6 million, respectively.

Additional information concerning the fair value of our oil and natural gas derivative instruments, including CNR derivatives assumed, is as follows:

	December 31,		
	2006	2005	2004
	(\$ in thousands)		
Fair value of contracts outstanding, as of January 1	\$ (945,814)	\$ 38,350	\$ (44,988)
Change in fair value of contracts during the period	3,423,099	(771,076)	(69,927)
Fair value of contracts when entered into during the period	(32,300)	(614,772)	(5,369)
Contracts realized or otherwise settled during the period	(1,253,653)	401,684	154,901
Fair value of contracts when closed during the period	(846,465)	—	3,733
Fair value of contracts outstanding, as of December 31	<u>\$ 344,867</u>	<u>\$ (945,814)</u>	<u>\$ 38,350</u>

Interest Rate Derivatives

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 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. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

Gains or losses from derivative transactions are reflected as adjustments to interest expense on the consolidated statements of operations. Realized gains (losses) included in interest expense were (\$1.9) million, \$4.9 million and \$0.8 million in 2006, 2005 and 2004, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as fair value 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 interest expense. Unrealized gains (losses) included in interest expense were \$1.6 million, \$1.6 million and (\$5.3) million in 2006, 2005 and 2004, respectively. A detailed explanation of accounting for interest rate derivatives under SFAS 133 appears under "Application of Critical Accounting Policies—Hedging" elsewhere in this Item 7.

Foreign Currency Derivatives

On December 5, 2006, we issued €600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the Euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. A detailed explanation of accounting for foreign currency derivatives under SFAS 133 appears under "Application of Critical Accounting Policies—Hedging" elsewhere in this Item 7.

Results of Operations

General. For the year ended December 31, 2006, Chesapeake had net income of \$2.003 billion, or \$4.35 per diluted common share, on total revenues of \$7.326 billion. This compares to net income of \$948.3 million, or \$2.51 per diluted common share, on total revenues of \$4.665 billion during the year ended December 31, 2005, and net income of \$515.2 million, or \$1.53 per diluted common share, on total revenues of \$2.709 billion during the year ended December 31, 2004.

Oil and Natural Gas Sales. During 2006, oil and natural gas sales were \$5.619 billion compared to \$3.273 billion in 2005 and \$1.936 billion in 2004. In 2006, Chesapeake produced and sold 578.4 bcfe at a weighted average price of \$8.86 per mcfe, compared to 468.6 bcfe in 2005 at a weighted average price of \$6.90 per mcfe, and 362.6 bcfe in 2004 at a weighted average price of \$5.23 per mcfe (weighted average prices for all years discussed exclude the effect of unrealized gains or (losses) on derivatives of \$495.5 million, \$41.1 million and \$40.9 million in 2006, 2005 and 2004, respectively). The increase in prices in 2006 resulted in an increase in revenue of \$1.135 billion and increased production resulted in a \$757.2 million increase, for a total increase in revenues of \$1.892 billion (excluding unrealized gains or losses on oil and natural 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 2006, we realized an average price per barrel of oil of \$59.14, compared to \$47.77 in 2005 and \$28.33 in 2004 (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 \$8.76, \$6.78 and \$5.29 in 2006, 2005 and 2004, respectively. Realized gains or losses from our oil and natural gas derivatives resulted in a net increase in oil and natural gas revenues of \$1.254 billion or \$2.17 per mcfe in 2006, a net decrease of \$401.7 million or \$0.86 per mcfe in 2005 and a net decrease of \$154.9 million or \$0.43 per mcfe in 2004.

A change in oil and natural gas prices has a significant impact on our oil and natural gas revenues and cash flows. Assuming 2006 production levels, a change of \$0.10 per mcf of natural gas sold would result in an increase or decrease in revenues and cash flow of approximately \$52.6 million and \$50.1 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 \$8.7 million and \$8.2 million, respectively, without considering the effect of hedging activities.

The following table shows our production by region for 2006, 2005 and 2004:

	Years Ended December 31,					
	2006		2005		2004	
	Mmcfe	Percent	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	315,173	55%	297,773	64%	268,459	74%
Fort Worth Barnett Shale	44,482	7	17,409	4	—	—
Appalachian Basin	45,031	8	5,878	1	—	—
Permian and Delaware Basins	48,510	8	42,958	9	32,067	9
Ark-La-Tex	46,009	8	40,707	9	19,640	5
South Texas and Texas Gulf Coast	79,178	14	63,852	13	42,427	12
Total Production	<u>578,383</u>	<u>100%</u>	<u>468,577</u>	<u>100%</u>	<u>362,593</u>	<u>100%</u>

Natural gas production represented approximately 91% of our total production volume on an equivalent basis in 2006, compared to 90% in 2005 and 89% in 2004.

Oil and Natural Gas Marketing Sales and Operating Expenses. Oil and natural gas marketing activities are substantially for third parties who are owners in Chesapeake-operated wells. Chesapeake realized \$1.576 billion in oil and natural gas marketing sales to third parties in 2006, with corresponding oil and natural gas marketing expenses of \$1.522 billion, for a net margin before depreciation of \$54 million. This compares to sales of \$1.393 billion and \$773 million, expenses of \$1.358 billion and \$755 million, and margins before depreciation of \$35 million and \$18 million in 2005 and 2004, respectively. In 2006 and 2005, Chesapeake realized an increase in volumes and prices related to oil and natural gas marketing sales as compared to the previous year.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our company-owned drilling and oilfield trucking operations. These operations have grown as a result of assets and businesses we acquired in 2006. Chesapeake recognized \$130.3 million in service operations revenue in 2006 with corresponding service operations expenses of \$67.9 million, for a net margin before depreciation of \$62.4 million. During 2005 and 2004, service operations revenues and expenses for third parties were insignificant.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were \$489.5 million in 2006, compared to \$317.0 million and \$204.8 million in 2005 and 2004, respectively. On a unit-of-production basis, production expenses were \$0.85 per mcf in 2006 compared to \$0.68 and \$0.56 per mcf in 2005 and 2004, respectively. The increase in 2006 was primarily due to higher third-party field service costs, fuel costs, ad valorem tax increases and personnel costs. We expect that production expenses per mcf produced for 2007 will range from \$0.90 to \$1.00.

Production Taxes. Production taxes were \$176.4 million in 2006 compared to \$207.9 million in 2005 and \$103.9 million in 2004. On a unit-of-production basis, production taxes were \$0.31 per mcf in 2006 compared to \$0.44 per mcf and \$0.29 per mcf in 2005 and 2004, respectively. The \$31.5 million decrease in production taxes in 2006 is due primarily to a price decrease of approximately \$1.06 per mcf (excluding gains or losses on derivatives) which more than offset the 109.8 bcf of increased production. In 2006, an accrual of \$11.6 million for certain severance tax claims was reversed as the result of the dismissal of such claims. The \$11.6 million accrual consisted of \$2.1 million in accruals made during 2006 and \$9.5 million in accruals made during 2005. Excluding these items, production taxes were \$0.32 per mcf in 2006 and \$0.42 per mcf in 2005. Included in 2004 is a credit of \$6.8 million, or \$0.02 per mcf, 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 natural 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 natural 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 natural gas prices are higher. We expect production taxes per mcfe to range from \$0.41 to \$0.46 during 2007 based on NYMEX prices of \$56.09 per barrel of oil and natural gas wellhead prices ranging from \$7.50 to \$8.50 per mcfe.

General and Administrative Expense. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our oil and natural gas properties (see Note 11 of notes to consolidated financial statements), were \$139.2 million in 2006, \$64.3 million in 2005 and \$37.0 million in 2004. General and administrative expenses were \$0.24, \$0.14 and \$0.10 per mcfe for 2006, 2005 and 2004, respectively. The increase in 2006 and 2005 was the result of the company's overall growth as well as cost and wage inflation. Included in general and administrative expenses is stock-based compensation of \$26.7 million in 2006, \$15.3 million in 2005 and \$4.8 million in 2004. Of this increase, \$1.1 million was due to stock option expense, \$10.2 million was due to a higher number of unvested restricted shares outstanding during 2006 compared to 2005 and \$0.1 million was due to stock granted to a new director. We anticipate that general and administrative expenses for 2007 will be between \$0.28 and \$0.35 per mcfe produced, including stock-based compensation ranging from \$0.08 and \$0.10 per mcfe produced.

Our stock-based compensation for employees and non-employee directors is in the form of restricted stock. We have awarded shares of restricted stock to employees since January 2004 and to non-employee directors since July 2005. Previously stock-based compensation awards were in the form of stock options. Employee stock-based compensation awards vest over a period of four years. Our non-employee director awards vest over a period of three years.

Until December 31, 2005, as permitted under Statement of Financial Accounting Standards ("SFAS") No. 123, *Accounting for Stock-Based Compensation*, as amended, we accounted for our stock options under the recognition and measurement provisions of APB Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. Generally, we recognized no compensation cost on grants of employee and non-employee director stock options because the exercise price was equal to the market price of our common stock on the date of grant. Effective January 1, 2006, we implemented the fair value recognition provisions of SFAS 123(R), *Share-Based Payment*, using the modified-prospective transition method. For all unvested options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, will be recognized in our financial statements over the remaining vesting period. For equity-based compensation awards granted or modified subsequent to January 1, 2006, compensation expense based on the fair value on the date of grant or modification will be recognized in our financial statements over the vesting period. In addition, in accordance with Financial Accounting Standards Board Staff Position No. FAS 123(R)-3, *Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards*, we elected to use the "short-cut" method to calculate the historical pool of windfall tax benefits. Results for prior periods have not been restated.

The discussion of stock-based compensation in Note 1 and Note 9 of the notes to consolidated financial statements included in Item 8 of this report provides additional detail on the accounting for and reporting of our stock options and restricted stock, as well as the effects of our adoption of SFAS 123(R).

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 \$160.6 million, \$102.2 million and \$51.7 million of internal costs in 2006, 2005 and 2004, respectively, directly related to our oil and natural gas property acquisition, exploration and development efforts.

Oil and Natural Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and natural gas properties was \$1.359 billion, \$894.0 million and \$582.1 million during 2006, 2005 and 2004, 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 \$2.35, \$1.91 and \$1.61 in 2006, 2005 and 2004, respectively. The increase in the average rate from \$1.91 in 2005 to \$2.35 in 2006 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 2007 DD&A rate to be between \$2.40 and \$2.60 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was \$104.2 million in 2006, compared to \$51.0 million in 2005 and \$29.2 million in 2004. The average D&A rate per mcfe was \$0.18, \$0.11 and \$0.08 in 2006, 2005 and 2004, respectively. The increase in 2006 and 2005 was primarily the result of higher depreciation costs resulting from the acquisition of various gathering facilities, compression equipment and drilling rig equipment, the 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 2006 and 2005. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 15 to 39 years, gathering facilities are depreciated over seven to 20 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 seven years. To the extent company-owned drilling rigs are used to drill our wells, a substantial portion of the depreciation is capitalized in oil and natural gas properties as exploration or development costs. We expect 2007 depreciation and amortization of other assets to be between \$0.24 and \$0.28 per mcfe produced.

Employee Retirement Expense. Our President and Chief Operating Officer, Tom L. Ward, resigned as a director, officer and employee of the company effective February 10, 2006. Mr. Ward's Resignation Agreement provided for the immediate vesting of all of his unvested equity awards, which consisted of options to purchase 724,615 shares of Chesapeake's common stock at an average exercise price of \$8.01 per share and 1,291,875 shares of restricted common stock. As a result of this vesting, we incurred an expense of \$54.8 million in 2006.

Provision for Legal Settlements. In 2004, we recorded a provision for legal settlement of \$4.5 million related to various litigation incidental to our business operations.

Interest and Other Income. Interest and other income was \$25.5 million, \$10.5 million and \$4.5 million in 2006, 2005 and 2004, respectively. The 2006 income consisted of \$5.2 million of interest income, \$10.3 million related to equity investments, a \$4.4 million gain on sale of assets and \$5.6 million of miscellaneous income. The 2005 income consisted of \$3.0 million of interest income, \$1.8 million of income related to equity investments and \$5.7 million of miscellaneous income. 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.

Interest Expense. Interest expense increased to \$300.7 million in 2006 compared to \$219.8 million in 2005 and \$167.3 million in 2004 as follows:

	Years Ended December 31,		
	2006	2005	2004
	(\$ in millions)		
Interest expense on senior notes and revolving bank credit facility	\$ 472.2	\$299.6	\$194.5
Capitalized interest	(179.1)	(79.0)	(36.2)
Amortization of loan discount	7.3	5.7	4.5
Unrealized (gain) loss on interest rate derivatives	(1.6)	(1.6)	5.3
Realized (gain) loss on interest rate derivatives	1.9	(4.9)	(0.8)
Total interest expense	<u>\$ 300.7</u>	<u>\$219.8</u>	<u>\$167.3</u>
Average long-term borrowings	<u>\$ 6,278</u>	<u>\$3,948</u>	<u>\$2,428</u>

Interest expense, excluding unrealized (gains) losses on derivatives and net of amounts capitalized, was \$0.52 per mcf in 2006 compared to \$0.47 per mcf in 2005 and \$0.45 per mcf in 2004. We expect interest expense for 2007 to be between \$0.60 and \$0.65 per mcf produced (before considering the effect of interest rate derivatives).

Gain on Sale of Investment. In 2006, Chesapeake sold its investment in publicly-traded Pioneer Drilling Company ("Pioneer") common stock, realizing proceeds of \$158.9 million and a gain of \$117.4 million. We owned 17% of the common stock of Pioneer, which we began acquiring in 2003.

Loss on Repurchases or Exchanges of Chesapeake Senior Notes. In 2005 and 2004, we repurchased or exchanged Chesapeake debt in order to re-finance a portion of our long-term debt at a lower rate of interest. The following table shows the losses we incurred in connection with these transactions (\$ in millions):

For the Year Ended December 31, 2005:	Notes Retired	Loss on Repurchases/Exchanges		
		Premium	Other (a)	Total
8.375% Senior Notes due 2008	\$ 19.0	\$ 1.2	\$ 0.1	\$ 1.3
8.125% Senior Notes due 2011	245.4	17.3	4.4	21.7
9.0% Senior Notes due 2012	300.0	41.4	6.0	47.4
	<u>\$564.4</u>	<u>\$59.9</u>	<u>\$10.5</u>	<u>\$70.4</u>
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
	<u>\$677.9</u>	<u>\$16.3</u>	<u>\$ 8.2</u>	<u>\$24.5</u>

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

Income Tax Expense. Chesapeake recorded income tax expense of \$1.252 billion in 2006 compared to income tax expense of \$545.1 million in 2005 and \$289.8 million in 2004. Of the \$706.9 million increase in 2006, \$643.1 million was the result of the increase in net income before taxes and \$63.8 million was the result of an increase in the effective tax rate. Our effective income tax rate was 38.5% in 2006 compared to 36.5% in 2005 and 36% in 2004. The increase in 2006 reflected the impact state income taxes and permanent differences had on our overall effective rate along with the effect of a Texas tax law change. In May 2006, Texas eliminated the existing franchise tax and replaced it with a new income-based margin tax. The new tax is effective for tax returns due on or after January 1, 2008 for our 2007 business activity. We recorded a \$15 million liability in 2006 to reflect the impact that this change had on our liability for additional deferred income taxes at the date of enactment. We expect our effective income tax rate to be 38% in 2007. Most of the 2006 income tax expense was deferred and we expect most of our 2007 income tax expense to be deferred.

Loss on Conversion/Exchange of Preferred Stock. Loss on conversion/exchange of preferred stock was \$10.6 million in 2006 compared to \$26.9 million in 2005 and \$36.7 million in 2004. 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. See Note 9 of notes to the consolidated financial statements in Item 8 for further detail regarding these transactions.

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, changes in interest rates and changes in foreign exchange rates. Recognized gains and losses on derivative contracts are reported as a component of the related transaction. Results of oil and natural gas derivative transactions are reflected in oil and natural gas sales, and results of interest rate and foreign exchange 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 natural 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 natural 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 confirmed the fair values 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 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 and foreign exchange 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, 2006, 2005 and 2004, the net market value of our derivatives was an asset of \$292.5 million, a liability of \$968.3 million and an asset of \$2.5 million,

respectively. The derivatives that we acquired in our CNR acquisition represented \$254.4 million and \$661.4 million of liability at December 31, 2006 and 2005. With respect to our derivatives held as of December 31, 2006, 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 \$45 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 \$10 million.

Oil and Natural Gas Properties. The accounting for our business is subject to special accounting rules that are unique to the oil and natural gas industry. There are two allowable methods of accounting for oil and natural 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 natural 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 natural 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 natural gas depreciation, depletion and amortization rate, and we will not have exploration expenses that successful efforts companies frequently have.

Under the full-cost method, capitalized costs are amortized on a composite unit-of-production method based on proved oil and natural 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. 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 natural 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. In calculating future net revenues, current prices and costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. 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. Any excess of the net book value, less deferred income taxes, is generally written off as an expense. Under SEC regulations, the excess above the ceiling is not expensed (or is reduced) if, subsequent to the end of the period, but prior to the release of the financial statements, oil and natural gas prices increase sufficiently such that an excess above the ceiling would have been eliminated (or reduced) if the increased prices were used in the calculations.

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 increase the likelihood of significant changes in these estimates.

As of December 31, 2006, approximately 80% of our proved reserves were evaluated by independent petroleum engineers, with the balance evaluated by our internal reservoir engineers. In addition, our internal engineers review and update 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. Additional information about our 2006 year-end reserve evaluation is included under "Oil and Natural Gas Reserves" in Item 1-Business.

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.

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 our 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 assets. As of December 31, 2006, we had deferred tax assets of \$407.0 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, *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.

We believe that the consideration we have paid for our oil and natural gas property acquisitions has represented the fair value of the assets and liabilities acquired at the time of purchase. Consequently, we have not recognized any goodwill from any of our oil and natural gas property acquisitions, nor do we expect to recognize goodwill from similar business combinations that we may complete in the future.

Disclosures About Effects of Transactions with Related Parties

As of December 31, 2006, we had accrued accounts receivable from our CEO, Aubrey K. McClendon, of \$11.1 million representing joint interest billings from December 2006 which were invoiced and paid in January 2007. Since Chesapeake was founded in 1989, Mr. McClendon has acquired working interests in virtually all of our oil and natural gas properties by participating in our drilling activities. Joint interest billings to him are settled in cash immediately upon delivery of a monthly joint interest billing.

Under the Founder Well Participation Program, approved by our shareholders in June 2005, Mr. McClendon (and our co-founder and former COO, Tom L. Ward prior to August 10, 2006) may elect to participate in all or none of the wells drilled by or on behalf of Chesapeake during a calendar year, but he is 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 not less than 30 days prior to the start of each calendar year. His participation is permitted only under the terms outlined in the Founder Well Participation Program, which, among other things, limits his 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 his participation. In addition, the company is reimbursed for costs associated with leasehold acquired by Mr. McClendon as a result of his well participation. Mr. Ward's participation in the Founder Well Participation Program terminated on August 10, 2006.

As disclosed in Note 8, in 2006, Chesapeake had revenues of \$867.3 million from oil and natural gas sales to Eagle Energy Partners I, L.P., an affiliated entity.

Recently Issued Accounting Standards

The Financial Accounting Standards Board (FASB) recently issued the following standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

In December 2004, the FASB 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. We adopted this statement effective January 1, 2006. The effect of SFAS 123(R) is more fully described in Note 1 of notes to the consolidated financial statements in Item 8 of this report.

In September 2005, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*. EITF Issue No. 04-13 requires that purchases and sales of inventory with the same counterparty in the same line of business should be accounted for as a single non-monetary exchange, if entered into in contemplation of one another. The consensus is effective for inventory arrangements entered into, modified or renewed in interim or annual reporting periods beginning after March 15, 2006. We adopted this issue effective April 1, 2006. The adoption of EITF Issue No. 04-13 did not have a material impact on our financial statements.

In June 2006, the FASB issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109*. FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS 109, *Accounting for Income Taxes*. FIN 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. FIN 48 is effective for fiscal years beginning after December 15, 2006. Based on our evaluation as of December 31, 2006, we do not expect that FIN 48 will have a material impact on our financial position, results of operations or cash flows.

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments—an amendment of FASB Statements No. 133 and 140*. SFAS 155 permits an entity to measure at fair value any financial instrument that contains an embedded derivative that otherwise would require bifurcation. This statement is effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after September 15, 2006. We are currently evaluating the provisions of SFAS 155 and believe that adoption will not have a material effect on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. We are currently assessing the impact SFAS 157 and believe that adoption will not have a material effect on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*. This statement requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. This statement is effective as of the end of the fiscal year ending after December 15, 2006. SFAS 158 did not have a material impact on our financial position, results of operations or cash flows.

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 natural gas reserve estimates, planned capital expenditures, the drilling of oil and natural gas wells and future acquisitions, expected oil and natural gas production, cash flow and anticipated liquidity, business strategy and other plans and

objectives for future operations and expected future expenses. 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 1A of this report and include:

- the volatility of oil and natural 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,
- our ability to replace reserves and sustain production,
- uncertainties inherent in estimating quantities of oil and natural gas reserves and projecting future rates of production and the timing of development expenditures,
- uncertainties in evaluating oil and natural gas reserves of acquired properties and associated potential liabilities,
- inability to effectively integrate and operate acquired companies and properties,
- unsuccessful exploration and development drilling,
- declines in the value of our oil and natural gas properties resulting in ceiling test write-downs,
- lower prices realized on oil and natural gas sales and collateral required to secure hedging liabilities resulting from our commodity price risk management activities,
- the negative effect lower oil and natural gas prices could have on our ability to borrow,
- drilling and operating risks,
- adverse effects of governmental and environmental regulation, and
- losses possible from pending or future litigation.

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 report and our other filings 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 Natural Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of December 31, 2006, our oil and natural 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 natural 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 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.
- Basis protection swaps are arrangements that guarantee a price differential for oil or natural gas from a specified delivery point. For Mid-Continent natural gas basis protection swaps, which have negative differentials to NYMEX, 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 Appalachian Basin basis natural gas protection swaps, which have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater 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, 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. Generally, 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 natural gas prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and natural 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 counter-swaps are recorded as adjustments to oil and natural gas sales.

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

Gains or losses from derivative transactions are reflected as adjustments to oil and natural gas sales in the consolidated statements of operations. Realized gains (losses) included in oil and natural gas sales were \$1.254 billion, (\$401.7) million and (\$154.9) million in the 2006, 2005 and 2004, respectively. 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 natural gas sales. Unrealized gains (losses) included in oil and natural gas sales were \$495.5 million, \$41.1 million and \$40.9 million in 2006, 2005 and 2004, 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 natural gas sales as unrealized gains (losses). We recorded an unrealized gain (loss) on ineffectiveness of \$311.1 million, (\$76.3) million and (\$8.2) million in 2006, 2005 and 2004, respectively.

As of December 31, 2006, we had the following open oil and natural gas derivative instruments (excluding derivatives assumed through our acquisition of CNR in November 2005) designed to hedge a portion of our oil and natural gas production for periods after December 2006:

	Volume	Net Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums Received (\$ in thousands)	Fair Value at December 31, 2006 (\$ in thousands)
Natural Gas (mmbtu):								
Swaps:								
1Q 2007	28,520,000	\$ 8.34	\$ —	\$ —	\$ —	Yes	\$ —	\$57,279
2Q 2007	3,930,000	5.55	—	—	—	Yes	—	(5,100)
3Q 2007	6,900,000	6.59	—	—	—	Yes	—	(3,060)
4Q 2007	6,900,000	7.58	—	—	—	Yes	—	(2,268)
1Q 2008	36,172,500	11.03	—	—	—	Yes	—	79,855
2Q 2008	49,822,500	8.36	—	—	—	Yes	—	42,869
3Q 2008	50,370,000	8.42	—	—	—	Yes	—	38,678
4Q 2008	50,370,000	9.03	—	—	—	Yes	—	40,266
Basis Protection Swaps (Mid-Continent):								
1Q 2007	37,350,000	—	—	—	(0.36)	No	—	10,028
2Q 2007	34,125,000	—	—	—	(0.35)	No	—	17,214
3Q 2007	34,500,000	—	—	—	(0.35)	No	—	14,814
4Q 2007	35,720,000	—	—	—	(0.32)	No	—	29,380
1Q 2008	33,215,000	—	—	—	(0.30)	No	—	31,192
2Q 2008	26,845,000	—	—	—	(0.25)	No	—	18,435
3Q 2008	27,140,000	—	—	—	(0.25)	No	—	16,385
4Q 2008	31,410,000	—	—	—	(0.28)	No	—	22,476
1Q 2009	26,100,000	—	—	—	(0.32)	No	—	16,737
2Q 2009	20,020,000	—	—	—	(0.28)	No	—	3,513
3Q 2009	20,240,000	—	—	—	(0.28)	No	—	2,818
4Q 2009	20,240,000	—	—	—	(0.28)	No	—	5,763
Basis Protection Swaps (Appalachian Basin):								
1Q 2007	9,000,000	—	—	—	0.35	No	—	(677)
2Q 2007	9,100,000	—	—	—	0.35	No	—	(554)
3Q 2007	9,200,000	—	—	—	0.35	No	—	(614)
4Q 2007	9,200,000	—	—	—	0.35	No	—	(93)
1Q 2008	9,100,000	—	—	—	0.35	No	—	706
2Q 2008	9,100,000	—	—	—	0.35	No	—	(276)
3Q 2008	9,200,000	—	—	—	0.35	No	—	(339)
4Q 2008	9,200,000	—	—	—	0.35	No	—	(35)
1Q 2009	4,500,000	—	—	—	0.31	No	—	301
2Q 2009	4,550,000	—	—	—	0.31	No	—	(95)
3Q 2009	4,600,000	—	—	—	0.31	No	—	(124)
4Q 2009	4,600,000	—	—	—	0.31	No	—	15
Cap-Swaps:								
1Q 2007	12,150,000	11.48	5.70	—	—	No	—	45,224
2Q 2007	19,110,000	9.57	5.91	—	—	No	—	17,225
3Q 2007	19,320,000	9.76	5.91	—	—	No	—	11,507
4Q 2007	19,320,000	10.56	5.91	—	—	No	—	13,003
1Q 2008	19,110,000	11.58	6.18	—	—	No	—	17,124
2Q 2008	19,110,000	10.00	6.18	—	—	No	—	7,782
3Q 2008	19,320,000	10.09	6.18	—	—	No	—	4,572
4Q 2008	19,320,000	10.65	6.18	—	—	No	—	5,429

	Volume	Net Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums Received (\$ in thousands)	Fair Value at December 31, 2006 (\$ in thousands)
Counter-Swaps:								
1Q 2007	(3,410,000)	(8.33)	—	—	—	No	—	(4,322)
2Q 2007	(1,375,000)	(7.73)	—	—	—	No	—	(1,133)
Call Options:								
1Q 2007	1,800,000	—	—	12.50	—	No	1,890	(11)
2Q 2007	1,820,000	—	—	12.50	—	No	1,911	(60)
3Q 2007	1,840,000	—	—	12.50	—	No	1,932	(261)
4Q 2007	1,840,000	—	—	12.50	—	No	1,932	(830)
1Q 2008	1,820,000	—	—	12.50	—	No	1,911	(1,421)
2Q 2008	1,820,000	—	—	12.50	—	No	1,911	(434)
3Q 2008	1,840,000	—	—	12.50	—	No	1,932	(682)
4Q 2008	1,840,000	—	—	12.50	—	No	1,932	(1,174)
Total Natural Gas							<u>15,351</u>	<u>547,027</u>
Oil (bbls):								
Swaps:								
1Q 2007	937,000	\$71.01	\$ —	\$ —	\$ —	Yes	\$ —	7,668
2Q 2007	1,092,000	70.04	—	—	—	Yes	—	5,759
3Q 2007	1,104,000	69.71	—	—	—	Yes	—	3,985
4Q 2007	1,104,000	69.31	—	—	—	Yes	—	2,568
1Q 2008	1,001,000	70.44	—	—	—	Yes	—	2,979
2Q 2008	1,001,000	70.02	—	—	—	Yes	—	2,339
3Q 2008	1,012,000	69.60	—	—	—	Yes	—	1,915
4Q 2008	920,000	68.79	—	—	—	Yes	—	1,095
1Q 2009	45,000	66.64	—	—	—	Yes	—	(28)
2Q 2009	45,500	66.27	—	—	—	Yes	—	(37)
3Q 2009	46,000	65.92	—	—	—	Yes	—	(44)
4Q 2009	46,000	65.56	—	—	—	Yes	—	(50)
Cap-Swaps:								
1Q 2007	360,000	78.53	56.25	—	—	No	—	5,499
2Q 2007	364,000	78.53	56.25	—	—	No	—	4,416
3Q 2007	368,000	78.53	56.25	—	—	No	—	3,745
4Q 2007	368,000	78.53	56.25	—	—	No	—	3,249
1Q 2008	273,000	77.60	55.00	—	—	No	—	1,982
2Q 2008	273,000	77.60	55.00	—	—	No	—	1,816
3Q 2008	276,000	77.60	55.00	—	—	No	—	1,719
4Q 2008	276,000	77.60	55.00	—	—	No	—	1,631
Total Oil							<u>—</u>	<u>52,206</u>
Total Natural Gas and Oil							<u>\$15,351</u>	<u>\$599,233</u>

We assumed certain liabilities related to open derivative positions in connection with our acquisition of Columbia Natural Resources, LLC in November 2005. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of \$592 million. The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our oil and natural gas revenues upon settlement. For example, if the fair value of the derivative positions assumed do not change, then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to oil and natural gas revenues related to the derivative positions. If, however, the actual sales price is different from the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in oil and natural gas revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes at market prices on the date of our acquisition of CNR.

Pursuant to Statement of Financial Accounting Standards No. 149, *Amendment of SFAS 133 on Derivative Instruments and Hedging Activities*, the derivative instruments assumed in connection with the CNR acquisition

are deemed to contain a significant financing element and all cash flows associated with these positions are reported as financing activity in the statement of cash flows for the periods in which settlement occurs.

The following details the assumed CNR derivatives remaining as of December 31, 2006:

	Volume	Net Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	SFAS 133 Hedge	Fair Value at December 31, 2006 (\$ in thousands)
Natural Gas (mmbtu):						
Swaps:						
1Q 2007	10,350,000	\$4.82	\$ —	\$ —	Yes	\$ (15,047)
2Q 2007	10,465,000	4.82	—	—	Yes	(18,834)
3Q 2007	10,580,000	4.82	—	—	Yes	(22,114)
4Q 2007	10,580,000	4.82	—	—	Yes	(30,822)
1Q 2008	9,555,000	4.68	—	—	Yes	(36,889)
2Q 2008	9,555,000	4.68	—	—	Yes	(24,796)
3Q 2008	9,660,000	4.68	—	—	Yes	(26,106)
4Q 2008	9,660,000	4.66	—	—	Yes	(31,177)
1Q 2009	4,500,000	5.18	—	—	Yes	(14,286)
2Q 2009	4,550,000	5.18	—	—	Yes	(8,209)
3Q 2009	4,600,000	5.18	—	—	Yes	(8,647)
4Q 2009	4,600,000	5.18	—	—	Yes	(10,517)
Collars:						
1Q 2009	900,000	—	4.50	6.00	Yes	(2,447)
2Q 2009	910,000	—	4.50	6.00	Yes	(1,316)
3Q 2009	920,000	—	4.50	6.00	Yes	(1,397)
4Q 2009	920,000	—	4.50	6.00	Yes	(1,762)
Total Natural Gas						<u><u>\$(254,366)</u></u>

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, 2006.

Based upon the market prices at December 31, 2006, we expect to transfer approximately \$282.5 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to earnings during the next 12 months in the related month of production. All transactions hedged as of December 31, 2006 are expected to mature by December 31, 2009.

Additional information concerning the fair value of our oil and natural gas derivative instruments, including CNR derivatives assumed, is as follows:

	December 31,		
	2006	2005	2004
	(\$ in thousands)		
Fair value of contracts outstanding, as of January 1	\$ (945,814)	\$ 38,350	\$ (44,988)
Change in fair value of contracts during the period	3,423,099	(771,076)	(69,927)
Fair value of contracts when entered into during the period	(32,300)	(614,772)	(5,369)
Contracts realized or otherwise settled during the period	(1,253,653)	401,684	154,901
Fair value of contracts when closed during the period	(846,465)	—	3,733
Fair value of contracts outstanding, as of December 31	<u>\$ 344,867</u>	<u>\$(945,814)</u>	<u>\$ 38,350</u>

The change in the fair value of our derivative instruments since January 1, 2006 resulted from the settlement of derivatives for a realized gain, as well as a decrease in natural gas prices. 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 natural 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.

In 2006, Chesapeake lifted a portion of its 2007, 2008 and 2009 hedges and as a result received \$744.1 million in cash from its hedging counterparties. The gain has been recorded in accumulated other comprehensive income and in oil and natural gas sales based on the designation of the hedges. For amounts initially recorded in other comprehensive income, the gain will be recognized in oil and natural gas sales in the month of the hedged production.

Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates. As of December 31, 2006, the fair value of the fixed-rate long-term debt has been estimated based on quoted market prices.

	Years of Maturity						Total	Fair Value
	2007	2008	2009	2010	2011	Thereafter		
	(\$ in billions)							
Liabilities:								
Long-term debt—fixed-rate (a)	\$—	\$—	\$—	\$—	\$ —	\$7.316	\$7.316	\$7.336
Average interest rate	—	—	—	—	—	6.5%	6.5%	6.5%
Long-term debt—variable rate	\$—	\$—	\$—	\$—	\$0.178	\$ —	\$0.178	\$0.178
Average interest rate	—	—	—	—	8.25%	—	8.25%	8.25%

(a) This amount does not include the discount included in long-term debt of (\$101.9) million and the discount for interest rate swaps of (\$17.0) 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 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 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. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

Gains or losses from derivative transactions are reflected as adjustments to interest expense in the consolidated statements of operations. Realized gains (losses) included in interest expense were (\$1.9) million, \$4.9 million and \$0.8 million in 2006, 2005 and 2004, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as fair value 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 interest expense. Unrealized gains (losses) included in interest expense were \$1.6 million, \$1.6 million and (\$5.3) million in 2006, 2005 and 2004, respectively.

As of December 31, 2006, the following interest rate swaps used to convert a portion of our long-term fixed-rate debt to floating-rate debt were outstanding:

<u>Term</u>	<u>Notional Amount</u>	<u>Fixed Rate</u>	<u>Floating Rate</u>	<u>Fair Value</u>
September 2004 – August 2012	\$ 75,000,000	9.000%	6 month LIBOR plus 452 basis points	\$(2,695)
July 2005 – January 2015	\$150,000,000	7.750%	6 month LIBOR plus 289 basis points	(5,866)
July 2005 – June 2014	\$150,000,000	7.500%	6 month LIBOR plus 282 basis points	(6,133)
September 2005 – August 2014	\$250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	(6,807)
October 2005 – June 2015	\$200,000,000	6.375%	6 month LIBOR plus 112 basis points	(2,860)
October 2005 – January 2018	\$250,000,000	6.250%	6 month LIBOR plus 99 basis points	(6,334)
December 2006 – July 2013	\$250,000,000	7.625%	6 month LIBOR plus 266.5 basis points	(2,755)
				<u>\$(33,450)</u>

In 2006, we closed six interest rate swaps for gains totaling \$5.7 million. These interest rate swaps were designated as fair value hedges, and the settlement amounts received will be amortized as a reduction to realized interest expense over the remaining terms of the related senior notes. Subsequent to December 31, 2006, we closed one interest rate swap for a gain of \$1.0 million.

Subsequent to December 31, 2006, we entered into the following interest rate swaps (which qualify as fair value hedges) to convert a portion of our long-term fixed-rate debt to floating-rate debt:

<u>Term</u>	<u>Notional Amount</u>	<u>Fixed Rate</u>	<u>Floating Rate</u>
January 2007 – July 2013	\$250,000,000	7.625%	6 month LIBOR plus 251 basis points
January 2007 – August 2017	\$250,000,000	6.500%	6 month LIBOR plus 124.5 basis points

Additionally, subsequent to December 31, 2006, we sold call options to a counterparty with respect to these two interest rate swaps and received \$3.7 million in premiums. If exercised, the call option on the 7.625% interest rate swap gives the counterparty the right to terminate the interest rate swap on July 12, 2007 for a payment to Chesapeake of \$2.0 million. The call option on the 6.50% interest rate swap gives the counterparty the right to terminate the interest rate swap on August 15, 2007 for a payment of \$2.0 million to Chesapeake.

Foreign Currency Derivatives

On December 5, 2006, we issued €600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the Euro-denominated senior notes, we entered into a cross currency swap

to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties will pay Chesapeake €18.75 million and Chesapeake will pay the counterparties \$29.95 million, which will yield an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake €600 million and Chesapeake will pay the counterparties \$799.5 million. The terms of the cross currency swap were based on the dollar/euro exchange rate on the issuance date of \$1.3325 to €1.00. Through the cross currency swap, we have eliminated any potential variability in Chesapeake's expected cash flows related to changes in foreign exchange rates and therefore the swap qualifies as a cash flow hedge under SFAS 133. The euro-denominated debt is recorded in notes payable (\$791.8 million at December 31, 2006) using an exchange rate of \$1.3197 to €1.00. The cross currency swap is recorded on the consolidated balance sheet at a fair value of (\$18.9) million at December 31, 2006. The translation adjustment to notes payable is completely offset by the fair value of the cross currency swap and therefore there is no impact to the consolidated statement of operations. The remaining value of the cross currency swap related to future interest payments is reported in other comprehensive income.

ITEM 8. *Financial Statements and Supplementary Data*

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CHESAPEAKE ENERGY CORPORATION**

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

It is the responsibility of the management of Chesapeake Energy Corporation to establish and maintain adequate 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 and has determined the Company's internal control over financial reporting was effective as of December 31, 2006.

Our management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its 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 integrated audits of Chesapeake Energy Corporation's consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, 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 present fairly, in all material respects, the financial position of Chesapeake Energy Corporation and its subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule 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.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing in Item 8, that the Company maintained effective internal control over financial reporting as of December 31, 2006 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, 2006, 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
Tulsa, Oklahoma

February 28, 2007

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2006	2005
	(\$ in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	\$ 2,519	\$ 60,027
Accounts receivable	844,851	791,194
Deferred income taxes	—	234,592
Short-term derivative instruments	224,996	10,503
Inventory and other	81,503	87,081
Total Current Assets	1,153,869	1,183,397
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, at cost based on full-cost accounting:		
Evaluated oil and natural gas properties	21,949,295	15,880,919
Unevaluated properties	3,796,405	1,739,095
Less: accumulated depreciation, depletion and amortization of oil and natural gas properties	(5,291,846)	(3,945,703)
Total oil and natural gas properties, at cost based on full-cost accounting	20,453,854	13,674,311
Other property and equipment:		
Natural gas gathering systems	552,608	333,365
Drilling rigs	300,810	116,133
Buildings and land	428,692	233,467
Natural gas compressors	126,806	73,043
Other	241,092	110,208
Less: accumulated depreciation and amortization of other property and equipment	(199,819)	(128,640)
Total Property and Equipment	21,904,043	14,411,887
OTHER ASSETS:		
Investments	698,962	297,443
Long-term derivative instruments	339,474	78,860
Other assets	320,819	146,875
Total Other Assets	1,359,255	523,178
TOTAL ASSETS	\$24,417,167	\$16,118,462

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS—(Continued)

	December 31,	
	2006	2005
	(\$ in thousands)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	\$ 859,745	\$ 516,792
Short-term derivative instruments	111,649	577,681
Accrued liabilities	419,361	364,501
Deferred income taxes	38,484	—
Revenues and royalties due others	318,303	394,693
Accrued interest	142,267	110,421
Total Current Liabilities	<u>1,889,809</u>	<u>1,964,088</u>
LONG-TERM LIABILITIES:		
Long-term debt, net	7,375,548	5,489,742
Deferred income tax liability	3,317,459	1,804,978
Asset retirement obligation	192,772	156,593
Long-term derivative instruments	160,283	479,996
Revenues and royalties due others	29,711	22,585
Other liabilities	200,114	26,157
Total Long-Term Liabilities	<u>11,275,887</u>	<u>7,980,051</u>
CONTINGENCIES AND COMMITMENTS (Note 4)		
STOCKHOLDERS' EQUITY:		
Preferred Stock, \$.01 par value, 20,000,000 shares authorized:		
6.00% cumulative convertible preferred stock, 0 and 99,310 shares issued and outstanding as of December 31, 2006 and 2005, respectively, entitled in liquidation to \$0 and \$4,965,500	—	4,966
5.00% cumulative convertible preferred stock (Series 2003), 0 and 1,025,946 shares issued and outstanding as of December 31, 2006 and 2005, respectively, entitled in liquidation to \$0 and \$102,594,600	—	102,595
4.125% cumulative convertible preferred stock, 3,065 and 89,060 shares issued and outstanding as of December 31, 2006 and 2005, respectively, entitled in liquidation to \$3,065,000 and \$89,060,000	3,065	89,060
5.00% cumulative convertible preferred stock (Series 2005), 4,600,000 shares issued and outstanding as of December 31, 2006 and 2005, entitled in liquidation to \$460,000,000	460,000	460,000
4.50% cumulative convertible preferred stock, 3,450,000 shares issued and outstanding as of December 31, 2006 and 2005, entitled in liquidation to \$345,000,000	345,000	345,000
5.00% cumulative convertible preferred stock (Series 2005B), 5,750,000 shares issued and outstanding as of December 31, 2006 and 2005, entitled in liquidation to \$575,000,000	575,000	575,000
6.25% mandatory convertible preferred stock, 2,300,000 and 0 shares issued and outstanding as of December 31, 2006 and 2005, respectively, entitled in liquidation to \$575,000,000 and \$0	575,000	—
Common Stock, \$.01 par value, 750,000,000 and 500,000,000 shares authorized, 458,600,789 and 375,510,521 shares issued December 31, 2006 and 2005, respectively	4,586	3,755
Paid-in capital	5,873,080	3,803,312
Retained earnings	2,913,722	1,100,841
Accumulated other comprehensive income (loss), net of tax of (\$318,889,000) and \$112,071,000, respectively	528,321	(194,972)
Unearned compensation	—	(89,242)
Less: treasury stock, at cost; 1,167,007 and 5,320,816 common shares as of December 31, 2006 and 2005, respectively	(26,303)	(25,992)
Total Stockholders' Equity	<u>11,251,471</u>	<u>6,174,323</u>
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	<u>\$24,417,167</u>	<u>\$16,118,462</u>

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,		
	2006	2005	2004
	(\$ in thousands, except per share data)		
REVENUES:			
Oil and natural gas sales	\$5,618,894	\$3,272,585	\$1,936,176
Oil and natural gas marketing sales	1,576,391	1,392,705	773,092
Service operations revenue	130,310	—	—
Total Revenues	7,325,595	4,665,290	2,709,268
OPERATING COSTS:			
Production expenses	489,499	316,956	204,821
Production taxes	176,440	207,898	103,931
General and administrative expenses	139,152	64,272	37,045
Oil and natural gas marketing expenses	1,521,848	1,358,003	755,314
Service operations expense	67,922	—	—
Oil and natural gas depreciation, depletion and amortization	1,358,519	894,035	582,137
Depreciation and amortization of other assets	104,240	50,966	29,185
Employee retirement expense	54,753	—	—
Provision for legal settlements	—	—	4,500
Total Operating Costs	3,912,373	2,892,130	1,716,933
INCOME FROM OPERATIONS	3,413,222	1,773,160	992,335
OTHER INCOME (EXPENSE):			
Interest and other income	25,463	10,452	4,476
Interest expense	(300,722)	(219,800)	(167,328)
Gain on sale of investment	117,396	—	—
Loss on repurchases or exchanges of Chesapeake senior notes	—	(70,419)	(24,557)
Total Other Income (Expense)	(157,863)	(279,767)	(187,409)
INCOME BEFORE INCOME TAXES	3,255,359	1,493,393	804,926
INCOME TAX EXPENSE:			
Current	5,000	—	—
Deferred	1,247,036	545,091	289,771
Total Income Tax Expense	1,252,036	545,091	289,771
NET INCOME	2,003,323	948,302	515,155
PREFERRED STOCK DIVIDENDS	(88,645)	(41,813)	(39,506)
LOSS ON CONVERSION/EXCHANGE OF PREFERRED STOCK	(10,556)	(26,874)	(36,678)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	\$1,904,122	\$ 879,615	\$ 438,971
EARNINGS PER COMMON SHARE:			
Basic	\$ 4.78	\$ 2.73	\$ 1.73
Assuming dilution	\$ 4.35	\$ 2.51	\$ 1.53
CASH DIVIDEND DECLARED PER COMMON SHARE	\$ 0.23	\$ 0.195	\$ 0.17
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in thousands):			
Basic	398,487	322,034	253,212
Assuming dilution	458,603	366,683	305,718

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,		
	2006	2005	2004
	(\$ in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME	\$ 2,003,323	\$ 948,302	\$ 515,155
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion, and amortization	1,449,442	935,965	605,593
Deferred income taxes	1,251,742	544,891	289,532
Unrealized (gains) losses on derivatives	(497,124)	(42,722)	(35,549)
Amortization of loan costs and bond discount	20,629	14,784	10,275
Realized (gains) losses on financing derivatives	(136,441)	(226)	—
Stock-based compensation	84,483	15,343	4,828
Gain on sale of investment in Pioneer Drilling Company	(117,396)	—	—
Income from equity investments	(9,966)	—	—
Loss on repurchases or exchanges of Chesapeake senior notes	—	70,419	24,557
Premiums paid for repurchasing of senior notes	—	(59,893)	(16,281)
Other	(3,583)	(1,136)	4,412
(Increase) decrease in accounts receivable	(21,634)	(204,860)	(152,590)
(Increase) decrease in inventory and other assets	(126,541)	(66,979)	(9,481)
Increase (decrease) in accounts payable, accrued liabilities and other	1,020,697	92,215	97,635
Increase (decrease) in current and non-current revenues and royalties due others	(74,157)	160,785	94,188
Cash provided by operating activities	<u>4,843,474</u>	<u>2,406,888</u>	<u>1,432,274</u>
CASH FLOWS FROM INVESTING ACTIVITIES:			
Acquisitions of oil and natural gas companies, proved and unproved properties, net of cash acquired	(3,960,094)	(4,134,782)	(2,054,673)
Exploration and development of oil and natural gas properties	(3,779,233)	(2,162,545)	(1,136,414)
Additions to buildings and other fixed assets	(593,715)	(417,470)	(126,707)
Additions to drilling rig equipment	(392,664)	(66,758)	(23,093)
Additions to investments	(554,591)	(135,013)	(36,962)
Acquisition of trucking company, net of cash acquired	(45,166)	—	—
Proceeds from sale of investment in Pioneer Drilling Company	158,890	—	—
Proceeds from sale of drilling rigs and equipment	243,615	—	—
Deposits for acquisitions	(21,700)	(35,000)	(16,250)
Divestitures of oil and natural gas properties	118	9,769	12,048
Sale of non-oil and natural gas assets and investments	1,902	20,422	860
Other	139	(1)	(13)
Cash used in investing activities	<u>(8,942,499)</u>	<u>(6,921,378)</u>	<u>(3,381,204)</u>
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term borrowings	8,370,000	5,682,000	2,160,000
Payments on long-term borrowings	(8,264,000)	(5,765,116)	(2,101,000)
Proceeds from issuance of senior notes, net of offering costs	1,754,846	2,924,636	1,165,975
Proceeds from issuance of common stock, net of offering costs	1,758,976	985,782	624,187
Proceeds from issuance of preferred stock, net of offering costs	557,627	1,341,529	304,936
Cash paid to purchase or exchange Chesapeake senior notes	—	(565,868)	(248,434)
Cash paid for common stock dividends	(87,008)	(60,528)	(38,902)
Cash paid for preferred stock dividends	(88,424)	(31,480)	(40,907)
Cash paid for financing cost of credit facilities	(5,496)	(4,672)	(9,175)
Cash paid for treasury stock	(86,185)	(4,000)	—
Derivative settlements	(86,923)	(11,642)	—
Net increase in outstanding payments in excess of cash balance	69,998	61,171	88,348
Cash received from exercise of stock options and warrants	73,172	21,612	11,987
Excess tax benefit from stock-based compensation	87,569	—	—
Other financing costs	(12,635)	(5,803)	(1,770)
Cash provided by financing activities	<u>4,041,517</u>	<u>4,567,621</u>	<u>1,915,245</u>
Net increase (decrease) in cash and cash equivalents	(57,508)	53,131	(33,685)
Cash and cash equivalents, beginning of period	60,027	6,896	40,581
Cash and cash equivalents, end of period	<u>\$ 2,519</u>	<u>\$ 60,027</u>	<u>\$ 6,896</u>

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,		
	2006	2005	2004
	(\$ in thousands)		
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH			
PAYMENTS FOR:			
Interest, net of capitalized interest	\$272,956	\$175,416	\$134,000
Income taxes, net of refunds received	\$ 294	\$ 200	\$ 239

SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:

As of December 31, 2006, 2005 and 2004, dividends payable on our common and preferred stock were \$52.9 million, \$37.9 million and \$19.4 million, respectively.

In 2006, 2005 and 2004, oil and natural gas properties were adjusted by \$179.7 million, \$251.7 million and \$463.9 million, respectively, for net income tax liabilities related to acquisitions.

During 2006, 2005 and 2004, accrued exploration and development costs of \$84.7 million, \$27.3 million and \$29.7 million, respectively, were recorded as additions to oil and natural gas properties.

We recorded non-cash asset additions to net oil and natural gas properties of \$23.2 million, \$76.8 million and \$20.2 million in 2006, 2005 and 2004, respectively, for asset retirement obligations.

In 2006, holders of our 5% (Series 2003) and 6% cumulative convertible preferred stock converted 38,625 shares and 99,310 shares into 235,447 shares and 482,694 shares of common stock at a conversion price of \$16.405 per share and \$10.287 per share, respectively.

In 2006, holders of our 4.125% and 5.0% (Series 2003) cumulative convertible preferred stock exchanged 83,245 shares and 804,048 shares for 5,248,126 and 4,972,786 shares of common stock, respectively, in public exchange offers.

In 2006, holders of our 4.125% and 5.0% (Series 2003) cumulative convertible preferred stock converted 2,750 shares and 183,273 shares into 172,594 shares and 1,140,223 shares of common stock, respectively, in privately negotiated exchanges.

In 2006, we acquired 32% of the outstanding common stock of Chaparral Energy, Inc. for \$240 million in cash and 1,375,989 newly issued shares of our common stock valued at \$40 million. Chaparral is a privately-held independent oil and natural gas company headquartered in Oklahoma City, Oklahoma.

In 2005, holders of our 6.0% cumulative convertible preferred stock converted 3,800 shares into 18,468 shares of common stock at a conversion price of \$10.287 per share.

In 2005, holders of our 4.125% and 5.0% (Series 2003) cumulative convertible preferred stock exchanged 224,190 and 699,054 shares for 14,321,881 and 4,362,720 shares, respectively, of common stock in privately negotiated exchanges.

In 2005, Chesapeake acquired Columbia Energy Resources, LLC and its subsidiaries, including Columbia Natural Resources, LLC ("CNR"), for a total consideration of \$3.02 billion, consisting of \$2.2 billion of cash and derivative liabilities, prepaid sales agreements and other liabilities of \$0.8 billion. See further discussion regarding the CNR acquisition in Note 13 of the notes to our consolidated financial statements.

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS—(Continued)

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 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.

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.

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,		
	2006	2005	2004
	(\$ in thousands)		
PREFERRED STOCK:			
Balance, beginning of period	\$ 1,576,621	\$ 490,906	\$ 552,400
Issuance of 6.25% mandatory convertible preferred stock	575,000	—	—
Issuance of 5.00% cumulative convertible preferred stock (Series 2005)	—	460,000	—
Issuance of 4.50% cumulative convertible preferred stock	—	345,000	—
Issuance of 5.00% cumulative convertible preferred stock (Series 2005B)	—	575,000	—
Issuance of 4.125% cumulative convertible preferred stock	—	—	313,250
Exchange of common stock for 85,995 and 224,190 shares of 4.125% preferred stock	(85,995)	(224,190)	—
Exchange of common stock for 1,025,946 and 699,054 shares of 5.00% preferred stock (Series 2003)	(102,595)	(69,905)	—
Exchange of common stock for 99,310, 3,800 and 4,496,890 shares of 6.00% preferred stock	(4,966)	(190)	(224,844)
Exchange of common stock for 2,998,000 shares of 6.75% preferred stock	—	—	(149,900)
Balance, end of period	<u>1,958,065</u>	<u>1,576,621</u>	<u>490,906</u>
COMMON STOCK:			
Balance, beginning of period	3,755	3,169	2,218
Issuance of 58,750,000, 32,200,000 and 46,000,000 shares of common stock	588	322	460
Issuance of 1,375,989 shares of common stock for the purchase of Chaparral Energy, Inc. common stock	14	—	—
Exchange of 12,251,870, 18,703,069 and 43,447,299 shares of common stock for preferred stock	122	187	435
Exercise of stock options and warrants	70	40	29
Restricted stock grants	37	37	27
Balance, end of period	<u>4,586</u>	<u>3,755</u>	<u>3,169</u>
PAID-IN CAPITAL:			
Balance, beginning of period	3,803,312	2,440,105	1,389,212
Issuance of common stock	1,799,100	1,024,282	649,520
Issuance of common stock for the purchase of Chaparral Energy, Inc. common stock	39,986	—	—
Exchange of 12,251,870, 18,703,069 and 43,447,299 shares of common stock for preferred stock	193,432	294,098	374,310
Equity-based compensation	99,617	82,144	41,485
Adoption of SFAS 123(R)	(89,242)	—	—
Offering expenses	(58,082)	(77,293)	(34,297)
Exercise of stock options and warrants	73,102	21,573	11,958
Release of 6,500,000 shares from treasury stock upon exercise of stock options	(75,102)	—	—
Tax benefit from exercise of stock options and restricted stock	87,569	18,506	9,135
Preferred stock conversion/exchange expenses	(612)	(103)	(1,218)
Balance, end of period	<u>5,873,080</u>	<u>3,803,312</u>	<u>2,440,105</u>
RETAINED EARNINGS (DEFICIT):			
Balance, beginning of period	1,100,841	262,987	(168,617)
Net income	2,003,323	948,302	515,155
Dividends on common stock	(95,809)	(64,830)	(45,229)
Dividends on preferred stock	(94,633)	(45,618)	(38,322)
Balance, end of period	<u>2,913,722</u>	<u>1,100,841</u>	<u>262,987</u>
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance, beginning of period	(194,972)	20,425	(20,312)
Hedging activity	809,534	(266,312)	15,946
Marketable securities activity	(86,241)	50,915	24,791
Balance, end of period	<u>528,321</u>	<u>(194,972)</u>	<u>20,425</u>
UNEARNED COMPENSATION:			
Balance, beginning of period	(89,242)	(32,618)	—
Restricted stock granted	—	(79,979)	(38,949)
Amortization of unearned compensation	—	23,355	6,331
Adoption of SFAS 123(R)	89,242	—	—
Balance, end of period	<u>—</u>	<u>(89,242)</u>	<u>(32,618)</u>
TREASURY STOCK—COMMON:			
Balance, beginning of period	(25,992)	(22,091)	(22,091)
Purchase of 2,707,471 and 257,220 shares of treasury stock	(86,185)	(4,000)	—
Release of 6,500,000 shares upon exercise of stock options	75,102	—	—
Release of 361,280 shares and 8,525 shares for company benefit plans	10,772	99	—
Balance, end of period	<u>(26,303)</u>	<u>(25,992)</u>	<u>(22,091)</u>
TOTAL STOCKHOLDERS' EQUITY	<u>\$11,251,471</u>	<u>\$6,174,323</u>	<u>\$3,162,883</u>

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2006	2005	2004
	(\$ in thousands)		
Net Income	\$2,003,323	\$ 948,302	\$515,155
Other comprehensive income (loss), net of income tax:			
Change in fair value of derivative instruments, net of income taxes of \$1,032,500,000, (\$317,772,000) and (\$44,463,000), respectively	1,711,196	(552,837)	(79,046)
Reclassification of (gain) loss on settled contracts, net of income taxes of (\$426,455,000), \$136,841,000 and \$50,480,000, respectively	(706,615)	238,066	89,743
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of (\$116,009,000), \$27,850,000 and \$2,953,000, respectively	(195,047)	48,452	5,249
Unrealized gain on marketable securities, net of income taxes of (\$7,826,000), \$29,266,000 and \$13,945,000, respectively	(13,155)	50,915	24,791
Reclassification of gain on sales of investments, net of income taxes of (\$45,824,000), \$0 and \$0, respectively	(73,086)	—	—
Other adjustments, net of income taxes of \$3,000	—	6	—
Comprehensive income	<u>\$2,726,616</u>	<u>\$ 732,904</u>	<u>\$555,892</u>

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 ("Chesapeake" or the "company") 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, Alabama, Arkansas, Louisiana, Kansas, Montana, Colorado, North Dakota, Nebraska, New Mexico, West Virginia, Kentucky, Ohio, New York, Maryland, Michigan, Mississippi, Pennsylvania, Tennessee, Utah, Virginia and Wyoming.

Principles of Consolidation

The accompanying consolidated financial statements of Chesapeake 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 original maturities of three months or less at date of purchase to be cash equivalents.

Accounts Receivable

Our accounts receivable are primarily from purchasers of oil and natural gas and exploration and production companies which own interests in properties we operate. 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.

Accounts receivable consists of the following components:

	December 31,	
	2006	2005
	(\$ in thousands)	
Oil and natural gas sales	\$617,780	\$615,382
Joint interest	135,348	89,669
Service operations	16,855	3
Related parties	12,158	12,839
Other	68,258	78,205
Allowance for doubtful accounts	(5,548)	(4,904)
Total accounts receivable	\$844,851	\$791,194

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Inventory

Inventory, which is included in current assets, includes 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. Purchased natural gas inventory is recorded at the lower of weighted average cost or market.

Oil and Natural 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 natural gas reserves. As of December 31, 2006, approximately 80% of our proved reserves were evaluated by independent petroleum engineers, with the balance evaluated by our internal reservoir engineers. In addition, our internal engineers evaluate all properties on an annual basis. The average composite rates used for depreciation, depletion and amortization were \$2.35 per mcf in 2006, \$1.91 per mcf in 2005 and \$1.61 per mcf in 2004.

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.

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 natural 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. In calculating future net revenues, current prices and costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. 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. Any excess of the net book value, less deferred income taxes, is generally written off as an expense. Under SEC regulations, the excess above the ceiling is not expensed (or is reduced) if, subsequent to the end of the period, but prior to the release of the financial statements, oil and natural gas prices increase sufficiently such that an excess above the ceiling would have been eliminated (or reduced) if the increased prices were used in the calculations.

We account for seismic costs in accordance with Rule 4-10 of Regulation S-X. Specifically, Rule 4-10 requires that all companies that use the full-cost method capitalize exploration costs as part of their oil and

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

natural gas properties (i.e., full-cost pool). Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Further, exploration costs include, among other things, geological and geophysical studies and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Such costs are capitalized as incurred. Seismic costs directly associated with the acquisition and evaluation of unproved properties are excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the properties. The company reviews its unproved properties and associated seismic costs quarterly in order to ascertain whether impairment has incurred. To the extent that seismic costs cannot be directly associated with specific unevaluated properties, they are included in the amortization base as incurred.

Other Property and Equipment

Other property and equipment consists primarily of natural gas gathering and processing facilities, drilling rigs, land, buildings and improvements, natural gas compressors, vehicles, office equipment, and software. Land purchases are made in order to build additional office space at our Oklahoma City headquarters and additional offices in various states. 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		Useful Life (in years)
	2006	2005	
	(\$ in thousands)		
Natural gas gathering systems	\$ 552,608	\$333,365	7 - 20
Buildings and improvements	304,959	159,001	15 - 39
Drilling rigs	300,810	116,133	15
Other fixtures and equipment	241,092	110,208	2 - 7
Natural gas compressors	126,806	73,043	15
Land	123,733	74,466	—
Total	\$1,650,008	\$866,216	

Investments

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 FASB Interpretation No. (FIN) 46, *Consolidation of Variable Interest Entities*.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

At December 31, 2006, investments accounted for under the equity method totaled \$627.9 million and investments accounted for under the cost method totaled \$71.1 million. Following is a summary of our investments:

	Approximate % Owned	Accounting Method	December 31,	
			2006 Carrying Value	2005 Carrying Value
(\$ in thousands)				
Chaparral Energy, Inc.	32%	Equity	\$280,000	\$ —
Frac Tech Services, Ltd.	20%	Equity	254,000	—
Gastar Exploration Ltd. (a)	17%	Cost	69,126	98,425
Eagle Energy Partners I, L.P.	33%	Equity	36,451	7,912
DHS Drilling Company	45%	Equity	25,770	15,245
Mountain Drilling Company	49%	Equity	23,587	27,609
Pioneer Drilling Company (b)	17%	Cost	—	138,095
Other	—	—	10,028	10,157
			<u>\$698,962</u>	<u>\$297,443</u>

(a) Our investment in Gastar had an associated cost basis of \$86.0 million and \$76.0 million as of December 31, 2006 and 2005, respectively.

(b) Our investment in Pioneer had an associated cost basis of \$42.7 million as of December 31, 2005.

Capitalized Interest

During 2006, 2005 and 2004, interest of approximately \$179.1 million, \$79.0 million and \$36.2 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 a weighted average interest rate based on our outstanding borrowings.

Accounts Payable and Accrued Liabilities

Included in accounts payable at December 31, 2006 and 2005, respectively, are liabilities of approximately \$247.8 million and \$177.8 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 \$176.7 million and \$88.3 million of accrued drilling costs as of December 31, 2006 and 2005, 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, 2006 and 2005 totaled \$116.0 million and \$92.2 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 Statement of Financial Accounting Standards (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 natural gas properties, this is the period in which an oil or natural gas well is acquired or drilled. The asset retirement obligation is capitalized as part of the carrying amount of our oil

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

and natural 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.

Natural Gas Imbalances. We follow the "sales method" of accounting for our natural gas revenue whereby we recognize sales revenue on all natural 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 natural gas reserves on the underlying properties. The natural gas imbalance net position at December 31, 2006 and 2005 was a liability of \$4.7 million and \$4.5 million, respectively.

Marketing Sales. Chesapeake takes title to the natural gas it purchases from other working interest owners in operated wells, 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 natural 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 natural gas derivative transactions are reflected in oil and natural 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 natural 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.

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 natural 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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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-Based Compensation

On January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payment* (SFAS 123(R)), to account for stock-based compensation. Among other items, SFAS 123(R) eliminates the use of APB Opinion No. 25 and the intrinsic value method of accounting for equity compensation and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the fair value at grant date of those awards in their financial statements. We elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. Upon adoption of SFAS 123(R), we elected to use the "short-cut" method to calculate the historical pool of windfall tax benefits in accordance with Financial Accounting Standards Board Staff Position No. FAS 123(R)-3, *Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards*, issued on November 10, 2005. For all unvested options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, will be recognized in our financial statements over the remaining vesting period. For equity-based compensation awards granted or modified subsequent to January 1, 2006, compensation expense based on the fair value on the date of grant or modification will be recognized in our financial statements over the vesting period. We utilize the Black-Scholes option pricing model to measure the fair value of stock options. To the extent compensation cost relates to employees directly involved in oil and natural gas exploration and development activities, such amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized as general and administrative expenses or production expenses.

Prior to the adoption of SFAS 123(R), we followed the intrinsic value method in accordance with APB 25 to account for employee stock-based compensation. Prior period financial statements have not been restated. Upon adoption of SFAS 123(R), we eliminated \$89.2 million of unearned compensation cost and reduced additional paid-in capital by the same amount on our consolidated balance sheet.

For the years ended December 31, 2006, 2005 and 2004, we recorded the following stock-based compensation (\$ in thousands):

<u>For the Year Ended December 31, 2006:</u>	<u>Restricted Stock</u>	<u>Stock Options</u>	<u>Total</u>
Production expenses	\$ 5,926	\$ 664	\$ 6,590
General and administrative expenses	22,989	3,672	26,661
Employee retirement expense	35,720	15,510	51,230
Oil and natural gas properties	21,058	2,214	23,272
Total	<u>\$85,693</u>	<u>\$22,060</u>	<u>\$107,753</u>
<u>For the Year Ended December 31, 2005:</u>			
Production expenses	\$ —	\$ —	\$ —
General and administrative expenses	12,759	2,584	15,343
Oil and natural gas properties	10,735	1,158	11,893
Total	<u>\$23,494</u>	<u>\$ 3,742</u>	<u>\$ 27,236</u>

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

	Restricted Stock	Stock Options	Total
For the Year Ended December 31, 2004:			
Production expenses	\$ —	\$—	\$ —
General and administrative expenses	4,243	585	4,828
Oil and natural gas properties	2,088	—	2,088
Total	\$6,331	\$585	\$6,916

SFAS 123 (R) generally did not change the accounting for awards of restricted stock. The impact to income before income taxes of adopting SFAS 123(R) for 2006 was a reduction of \$3.1 million associated with stock option awards. SFAS 123(R) also requires cash inflows resulting from tax deductions in excess of compensation expense recognized for stock options and restricted stock (“excess tax benefits”) to be classified as financing cash inflows in our statements of cash flows. Accordingly, for the year ended December 31, 2006, we reported \$87.6 million of excess tax benefits from stock-based compensation as cash provided by financing activities on our statement of cash flows.

Pro forma Disclosures

Prior to January 1, 2006, we accounted for our employee and non-employee director stock options using the intrinsic value method prescribed by APB 25. As required by SFAS 123(R), we have disclosed below the effect on net income and earnings per share that would have been recorded using the fair value based method for 2005 and 2004 (\$ in thousands, except per share amounts):

	Years Ended December 31,	
	2005	2004
Net Income:		
As reported	\$948,302	\$515,155
Add: Stock-based compensation expense included in reported net income, net of income tax	9,743	3,090
Deduct: Total stock-based compensation expense determined under fair value based method for all awards, net of income tax	(18,028)	(14,289)
Pro forma net income	\$940,017	\$503,956
Basic earnings per common share:		
As reported	\$ 2.73	\$ 1.73
Pro forma	\$ 2.71	\$ 1.69
Diluted earnings per common share:		
As reported	\$ 2.51	\$ 1.53
Pro forma	\$ 2.48	\$ 1.49

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for 2005 and 2004 to conform to the presentation used for the 2006 consolidated financial statements.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

2. Net Income Per Share

Statement of Financial Accounting Standards No. 128, *Earnings Per Share (EPS)*, 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 EPS, as the effect was antidilutive:

- For the years ended December 31, 2005 and 2004, outstanding options to purchase 0.1 million shares of common stock at a weighted-average exercise price of \$29.85 and \$23.82, 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, 2006 and 2005, diluted shares do not include the common stock equivalent of our 4.125% preferred stock outstanding prior to conversion (convertible into 2,090,292 and 8,610,708 shares, respectively) and the preferred stock adjustments to net income do not include \$9.1 million and \$28.9 million, respectively, of dividends and loss on conversion/exchange related to these preferred shares, as the effect on diluted earnings per share would have been antidilutive.
- 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) and the preferred stock adjustment to net income does not include \$12.2 million of dividends related to these preferred shares, as the effect on diluted earnings per share would have been antidilutive.

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 guidance on when the dilutive effect of contingently convertible securities with a market price trigger should be included in diluted EPS. EITF 04-8 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 assumed the conversion of the 4.125% convertible preferred shares issued in 2004 (if dilutive) for purposes of determining EPS assuming dilution.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

A reconciliation for the years ended December 31, 2006, 2005 and 2004 is as follows:

	<u>Income</u> <u>(Numerator)</u>	<u>Shares</u> <u>(Denominator)</u>	<u>Per</u> <u>Share</u> <u>Amount</u>
	(in thousands, except per share data)		
For the Year ended December 31, 2006:			
Basic EPS:			
Income available to common shareholders	\$1,904,122	398,487	\$4.78
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	—	184	
Common shares assumed issued for 4.50% convertible preferred stock	—	7,811	
Common shares assumed issued for 5.00% (Series 2005) convertible preferred stock	—	17,856	
Common shares assumed issued for 5.00% (Series 2005B) convertible preferred stock	—	14,717	
Common shares assumed issued for 6.25% mandatory convertible preferred stock	—	9,217	
Assumed conversion as of the beginning of the period of preferred shares outstanding prior to conversion:			
Common stock equivalent of preferred stock outstanding prior to conversion, 5.00% (Series 2003) convertible preferred stock	—	2,308	
6.00% convertible preferred stock	—	103	
Employee stock options	—	6,043	
Restricted stock	—	1,877	
Loss on redemption of preferred stock	2,886	—	
Preferred stock dividends	87,214	—	
Diluted EPS Income available to common shareholders and assumed conversions	<u>\$1,994,222</u>	<u>458,603</u>	<u>\$4.35</u>

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

	<u>Income</u> <u>(Numerator)</u>	<u>Shares</u> <u>(Denominator)</u>	<u>Per</u> <u>Share</u> <u>Amount</u>
	(in thousands, except per share data)		
For the Year ended December 31, 2005:			
Basic EPS:			
Income available to common shareholders	<u>\$879,615</u>	<u>322,034</u>	<u>\$2.73</u>
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	—	5,349	
Common shares assumed issued for 4.50% convertible preferred stock	—	2,332	
Common shares assumed issued for 5.00% (Series 2003) convertible preferred stock	—	6,254	
Common shares assumed issued for 5.00% (Series 2005) convertible preferred stock	—	12,532	
Common shares assumed issued for 5.00% (Series 2005B) convertible preferred stock	—	2,177	
Common shares assumed issued for 6.00% convertible preferred stock	—	483	
Assumed conversion as of the beginning of the period of preferred shares			
outstanding prior to conversion:			
Common stock equivalent of preferred stock outstanding prior to conversion,			
5.00% (Series 2003) convertible preferred stock	—	3,024	
6.00% convertible preferred stock	—	12	
Employee stock options	—	10,861	
Restricted stock	—	1,614	
Warrants assumed in Gothic acquisition	—	11	
Loss on redemption of preferred stock	3,519	—	
Preferred stock dividends	<u>36,278</u>	<u>—</u>	
Diluted EPS Income available to common shareholders and assumed conversions	<u>\$919,412</u>	<u>366,683</u>	<u>\$2.51</u>
For the Year ended December 31, 2004:			
Basic EPS:			
Income available to common shareholders	<u>\$438,971</u>	<u>253,212</u>	<u>\$1.73</u>
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% (Series 2003) 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	
Employee stock options	—	10,097	
Restricted stock	—	203	
Warrants assumed in Gothic acquisition	—	18	
Preferred stock dividends	<u>27,290</u>	<u>—</u>	
Diluted EPS Income available to common shareholders and assumed conversions	<u>\$466,261</u>	<u>305,718</u>	<u>\$1.53</u>

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

3. Senior Notes and Revolving Bank Credit Facility

Our long-term debt consisted of the following at December 31, 2006 and 2005:

	December 31,	
	2006	2005
	(\$ in thousands)	
7.5% Senior Notes due 2013	\$ 363,823	\$ 363,823
7.625% Senior Notes due 2013	500,000	—
7.0% Senior Notes due 2014	300,000	300,000
7.5% Senior Notes due 2014	300,000	300,000
7.75% Senior Notes due 2015	300,408	300,408
6.375% Senior Notes due 2015	600,000	600,000
6.625% Senior Notes due 2016	600,000	600,000
6.875% Senior Notes due 2016	670,437	670,437
6.5% Senior Notes due 2017	1,100,000	600,000
6.25% Euro-denominated Senior Notes due 2017 (a)	791,820	—
6.25% Senior Notes due 2018	600,000	600,000
6.875% Senior Notes due 2020	500,000	500,000
2.75% Contingent Convertible Senior Notes due 2035 (b)	690,000	690,000
Revolving bank credit facility	178,000	72,000
Discount on senior notes	(101,935)	(95,577)
Discount for interest rate derivatives (c)	(17,005)	(11,349)
Total notes payable and long-term debt	<u>\$7,375,548</u>	<u>\$5,489,742</u>

- (a) The principal amount shown is based on the dollar/euro exchange rate of \$1.3197 to €1.00 as of December 31, 2006. See Note 10 for information on our related cross currency swap.
- (b) The holders of the 2.75% Contingent Convertible Senior Notes due 2035 may require us to repurchase all or a portion of these notes on November 15, 2015, 2020, 2025 and 2030, or upon a fundamental change, at 100% of the principal amount of these notes. The notes are convertible, at the holder's option, prior to maturity under certain circumstances, into cash and, if applicable, shares of our common stock using a net share settlement process. In general, upon conversion of a convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note's conversion value in excess of such principal amount. In addition, we will pay contingent interest on the convertible senior notes, beginning with the nine-month period ending May 14, 2016, under certain conditions. We may redeem the convertible senior notes on or after November 15, 2015 at a redemption price of 100% of the principal amount of such notes.
- (c) See Note 10 for further discussion related to these instruments.

There were no repurchases or exchanges of Chesapeake debt in 2006. The following table sets forth the losses we incurred in connection with repurchases and exchanges of senior notes in 2005 and 2004:

<u>For the Year Ended December 31, 2005:</u>	<u>Notes Retired</u>	<u>Loss on Repurchases/Exchanges</u>		
		<u>Premium</u>	<u>Other (a)</u>	<u>Total</u>
8.375% Senior Notes due 2008	\$ 19.0	\$ 1.2	\$ 0.1	\$ 1.3
8.125% Senior Notes due 2011	245.4	17.3	4.4	21.7
9.0% Senior Notes due 2012	300.0	41.4	6.0	47.4
	<u>\$564.4</u>	<u>\$59.9</u>	<u>\$10.5</u>	<u>\$70.4</u>

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

	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
	<u>\$677.9</u>	<u>\$16.3</u>	<u>\$8.2</u>	<u>\$24.5</u>

(a) Includes the write-off of unamortized discounts, deferred charges, transaction costs and derivative charges as described below.

Our outstanding senior notes are unsecured senior obligations of Chesapeake that rank equally in right of payment with all of our existing and future senior indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. We may redeem the senior notes, other than the 2.75% Contingent Convertible Senior Notes due 2035, at any time at specified make-whole or redemption prices. Senior notes issued before July 2005 are governed by indentures containing covenants that limit 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; enter into sale-leaseback transactions; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. Senior notes issued after June 2005 are governed by indentures containing covenants that limit our ability and our guarantor subsidiaries' ability to incur certain secured indebtedness; enter into sale-leaseback transactions; and consolidate, merge or transfer assets.

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, jointly and severally, by all of our wholly owned subsidiaries, other than minor subsidiaries, on a senior unsecured basis.

We have a \$2.5 billion syndicated revolving bank credit facility which matures in February 2011. The credit facility was increased from \$1.25 billion to \$2.0 billion in February 2006 and to \$2.5 billion in September 2006. As of December 31, 2006, we had \$178.0 million in outstanding borrowings under our facility and utilized \$6.2 million of the facility for various letters of credit. Borrowings under our facility are collateralized by certain producing oil and natural 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 from 0.875% to 1.50% 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 a commitment fee that also varies according to our senior unsecured long-term debt ratings, from 0.125% to 0.30% per annum. Currently, the commitment fee rate is 0.25% per annum. 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, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.65 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.5 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.40 to 1 and our indebtedness to EBITDA ratio was 1.64 to 1 at December 31, 2006. 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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

immediately due and payable. Such acceleration, if involving a principal amount of \$10 million (\$50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of a significant portion 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 \$75 million.

Two of our subsidiaries, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., are the borrowers under our revolving bank credit facility. The facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and all of our other wholly owned subsidiaries except minor subsidiaries.

4. Contingencies and Commitments

Litigation. We are involved in various disputes incidental to our business operations, including claims from royalty owners regarding volume measurements, post-production costs and prices for royalty calculations. In *Tawney, et al. v. Columbia Natural Resources, Inc.*, Chesapeake's wholly owned subsidiary Chesapeake Appalachia, L.L.C., formerly known as Columbia Natural Resources, LLC (CNR), is a defendant in a class action lawsuit in the Circuit Court of Roane County, West Virginia filed in 2003 by royalty owners. The plaintiffs allege that CNR underpaid royalties by improperly deducting post-production costs, failing to pay royalty on total volumes of natural gas produced and not paying a fair value for the natural gas produced from their leases. The plaintiff class consists of West Virginia royalty owners receiving royalties after July 31, 1990 from CNR. Chesapeake acquired CNR in November 2005, and its seller acquired CNR in 2003 from NiSource Inc. NiSource, a co-defendant in the case, has managed the litigation and indemnified Chesapeake against underpayment claims based on the use of fixed prices for natural gas production sold under certain forward sale contracts and other claims with respect to CNR's operations prior to September 2003.

On January 27, 2007, the Circuit Court jury returned a verdict against the defendants of \$404 million, consisting of \$134 million in compensatory damages and \$270 million in punitive damages. Most of the damages awarded by the jury relate to issues not yet addressed by the West Virginia Supreme Court of Appeals, although in June 2006 that Court ruled against the defendants on two certified questions regarding the deductibility of post-production expenses. The jury found fraud with respect to the sales prices used to calculate royalty payments and with respect to the failure of CNR to disclose post-production deductions.

Chesapeake and NiSource maintain CNR acted in good faith and paid royalties in accordance with lease terms and West Virginia law, and they intend to appeal any adverse judgment in the case. Chesapeake and NiSource have filed a joint motion for post-trial review of punitive damages to be heard on March 5, 2007. Chesapeake has established an accrual for amounts it believes will not be indemnified. Should a final nonappealable judgment be entered, Chesapeake believes its share of damages will not have a material adverse effect on its results of operations, financial condition or liquidity.

Chesapeake is subject to other legal proceedings and claims which arise in the ordinary course of business. In our opinion, the final resolution of these proceedings and claims will not have a material effect on the company.

Employment Agreements with Officers. Chesapeake has employment agreements with its chief executive officer, chief operating officer, chief financial officer and other executive officers, which provide for annual base salaries, various benefits and eligibility for bonus compensation. The agreement with the chief executive officer has a term of five years commencing January 1, 2007. The term of the agreement is automatically extended for

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

one additional year on each December 31 unless the company provides 30 days notice of non-extension. In the event of termination of employment without cause, the chief executive officer's base compensation (defined as base salary plus bonus compensation received during the preceding 12 months) and benefits would continue during the remaining term of the agreement. The chief executive officer is entitled to receive a payment in the amount of three times his base compensation and three times the value of the prior year's benefits, plus a tax gross-up payment, upon the happening of certain events following a change of control, and the company will also provide him office space and secretarial and accounting support for a period of 12 months thereafter. Any stock-based awards held by the chief executive officer and deferred compensation will immediately become 100% vested upon termination of employment without cause, a change of control event, incapacity, death or retirement at or after age 55, and any unexercised stock options will not terminate as the result of termination of employment. The agreements with the chief operating officer, chief financial officer and other executive officers expire on September 30, 2009. These agreements provide for the continuation of salary for one year in the event of termination of employment without cause or death and, in the event of a change of control, a payment in the amount of two times the executive officer's base compensation. These executive officers are entitled to continue to receive compensation and benefits for 180 days following termination of employment as a result of incapacity. Any stock-based awards held by such executive officers will immediately become 100% vested upon termination of employment without cause, a change of control, death or retirement at or after age 55.

Environmental Risk. Due to the nature of the oil and natural 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 contingent 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, 2006.

Rig and Other Leases. In a series of transactions in 2006, our wholly owned subsidiary, Nomac Drilling Corporation, sold 24 of its drilling rigs and related equipment for \$244 million and entered into a master lease agreement under which it agreed to lease the rigs from the buyer for an initial term of eight years for rental payments of approximately \$33 million annually. Nomac's lease obligations are guaranteed by Chesapeake and its other material domestic subsidiaries. These transactions were recorded as sale and operating leasebacks, with an aggregate deferred gain of \$28.6 million on the sale which will be amortized to service operations expense over the lease term. Under the rig lease, we have the option to purchase the rigs in 2013 or on the expiration of the lease term for a purchase price equal to the then fair market value of the rigs. Additionally, we have the option to renew the rig lease for a negotiated renewal term at a periodic rental equal to the fair market rental value of the rigs as determined at the time of renewal.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Commitments related to these lease payments and other operating leases are not recorded in the accompanying consolidated balance sheets. As of December 31, 2006, minimum future rig lease payments were as follows (\$ in thousands):

	<u>Rigs</u>	<u>Other</u>
2007	\$ 33,278	\$ 6,755
2008	33,394	5,946
2009	33,394	4,279
2010	33,394	1,873
2011	33,394	1,004
After 2011	<u>93,576</u>	<u>1,687</u>
Total	<u>\$260,430</u>	<u>\$21,544</u>

Rent expense, including short-term rentals, for the years ended December 31, 2006, 2005 and 2004 was \$47.3 million, \$29.8 million and \$17.9 million, respectively.

Transportation Contracts. Chesapeake has various firm pipeline transportation service agreements with expiration dates ranging from one to 93 years. These commitments are not recorded in the accompanying consolidated balance sheets. Under the terms of these contracts, we are obligated to pay demand charges as set forth in the transporter's Federal Energy Regulatory Commission (FERC) gas tariff. In exchange, the company will receive rights to flow natural gas production through pipelines located in highly competitive markets. Excluded from this summary are demand charges for pipeline projects that are currently seeking regulatory approval. The aggregate amounts of such required demand payments as of December 31, 2006 are as follows (\$ in thousands):

2007	\$ 21,983
2008	32,582
2009	38,504
2010	36,232
2011	31,869
After 2011	<u>220,461</u>
Total	<u>\$381,631</u>

In addition, the company is required to pay additional amounts depending on actual quantities shipped under the agreements. The company's total payments under the agreements were \$94.9 million in 2006 and \$1.4 million in 2005.

Drilling Contracts. We have contracts with various drilling contractors to use 45 drilling rigs in 2007 with terms of one to three years. These commitments are not recorded in the accompanying consolidated balance sheets. Minimum future commitments as of December 31, 2006 are as follows (\$ in thousands):

2007	\$227,796
2008	133,696
2009	33,540
2010	821
After 2010	—
Total	<u>\$395,853</u>

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Chesapeake's service operations companies, as of December 31, 2006, had contracted to acquire 15 rigs to be constructed during 2007. The total remaining cost of the rigs is estimated to be approximately \$141.9 million.

Other. As of December 31, 2006, Chesapeake has contracted to acquire compressors during 2007 and 2008 for a total commitment of \$149.0 million which is not recorded in the accompanying consolidated balance sheets.

Chesapeake and a leading investment bank have an agreement to lend Mountain Drilling Company, of which Chesapeake is a 49% equity owner, up to \$25 million each through December 31, 2009. There was \$25 million outstanding under this agreement at December 31, 2006.

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,		
	2006	2005	2004
	(\$ in thousands)		
Current	\$ 5,000	\$ —	\$ —
Deferred	1,247,036	545,091	289,771
Total	\$1,252,036	\$545,091	\$289,771

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,		
	2006	2005	2004
	(\$ in thousands)		
Computed "expected" federal income tax provision	\$1,139,376	\$522,688	\$281,724
State income taxes and other	112,941	22,608	8,230
Tax percentage depletion	(281)	(205)	(183)
	\$1,252,036	\$545,091	\$289,771

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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:

	<u>Years Ended December 31,</u>	
	<u>2006</u>	<u>2005</u>
	(\$ in thousands)	
Deferred tax liabilities:		
Oil and natural gas properties	\$(3,259,260)	\$(2,227,960)
Other property and equipment	(105,891)	(26,679)
Derivative instruments	(397,811)	—
Investments	—	(42,211)
Deferred tax liabilities	<u>(3,762,962)</u>	<u>(2,296,850)</u>
Deferred tax assets:		
Net operating loss carryforwards	\$ 290,471	\$ 246,857
Asset retirement obligation	73,793	59,525
Derivative instruments	—	358,660
Investments	7,041	—
Accrued liabilities	4,455	30,648
Percentage depletion carryforwards	5,934	4,603
Alternative minimum tax credits	5,822	5,298
Other	19,503	20,873
Deferred tax assets	<u>407,019</u>	<u>726,464</u>
Total deferred tax asset (liability)	<u>\$(3,355,943)(a)</u>	<u>\$(1,570,386)</u>
Reflected in accompanying balance sheets as:		
Current deferred income tax asset	\$ —	\$ 234,592
Current deferred income tax liability	(38,484)	—
Non-current deferred income tax liability	<u>(3,317,459)</u>	<u>(1,804,978)</u>
	<u>\$(3,355,943)</u>	<u>\$(1,570,386)</u>

(a) In addition to the income tax expense of \$1.252 billion, activity during 2006 includes a net liability of \$190.4 million related to acquisitions, a liability of \$480.7 million related to derivative instruments, a benefit of \$49.8 million related to investments, a benefit of \$87.6 million related to stock-based compensation and a benefit of \$0.1 million related to other miscellaneous items. These items were not recorded as part of the provision for income taxes.

As of December 31, 2006, we classified \$38.5 million of deferred tax liabilities as current that were attributable to the current portion of derivative assets and other current temporary differences. As of December 31, 2005, we classified \$234.6 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, 2006, Chesapeake had federal income tax net operating loss (NOL) carryforwards of approximately \$631.1 million. Additionally, we had \$3.6 million of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income and approximately \$15.9 million of percentage depletion carryforwards. The NOL carryforwards expire from 2011 through 2026. The value of these

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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:

	<u>NOL</u>	<u>AMT NOL</u>
	<u>(\$ in thousands)</u>	
Expiration Date:		
December 31, 2011	\$119,592	\$ —
December 31, 2012	51,996	—
December 31, 2018	42,187	—
December 31, 2019	149,627	—
December 31, 2020	5,156	—
December 31, 2021	15,371	—
December 31, 2022	50,410	—
December 31, 2023	66,816	2,740
December 31, 2024	61,171	6
December 31, 2025	30,434	819
December 31, 2026	38,363	—
Total	<u>\$631,123</u>	<u>\$3,565</u>

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, 2006 and any related limitations:

	<u>Total</u>	<u>Limited</u>	<u>Annual Limitation</u>
	<u>(\$ in thousands)</u>		
Net operating loss	\$631,123	\$30,570	\$15,568
AMT net operating loss	\$ 3,565	\$ 3,565	\$ 520

As of December 31, 2006, we do not believe that an ownership change has occurred. 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, 2006, we had accrued accounts receivable from our CEO, Aubrey K. McClendon, of \$11.1 million representing joint interest billings from December 2006 which were invoiced and paid in January 2007. Since

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Chesapeake was founded in 1989, Mr. McClendon has acquired working interests in virtually all of our oil and natural gas properties by participating in our drilling activities. Joint interest billings to him are settled in cash immediately upon delivery of a monthly joint interest billing.

Under the Founder Well Participation Program, approved by our shareholders in June 2005, Mr. McClendon (and our co-founder and former COO, Tom L. Ward prior to August 10, 2006) may elect to participate in all or none of the wells drilled by or on behalf of Chesapeake during a calendar year, but he is 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 not less than 30 days prior to the start of each calendar year. His participation is permitted only under the terms outlined in the Founder Well Participation Program, which, among other things, limits his 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 his participation. In addition, the company is reimbursed for costs associated with leasehold acquired by Mr. McClendon as a result of his well participation. Mr. Ward's participation in the Founder Well Participation Program terminated on August 10, 2006.

As disclosed in Note 8, in 2006, 2005 and 2004 Chesapeake had revenues of \$867 million, \$851 million and \$467 million, respectively, from oil and natural gas sales to Eagle Energy Partners I, L.P., an affiliated entity.

7. Employee Benefit Plans

Our qualified 401(k) profit sharing plan is the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan, which is open to employees of Chesapeake and all our subsidiaries except certain employees of Chesapeake Appalachia, L.L.C. On January 1, 2007, a plan we maintained for the employees of our subsidiary Nomac Drilling Corporation was merged into the Chesapeake plan. Eligible employees may elect to defer compensation through voluntary contributions to their 401(k) plan accounts, subject to plan limits and those set by the Internal Revenue Service. Chesapeake matches employee contribution dollar for dollar with Chesapeake common stock purchased in the open market for up to a portion of an employee's annual compensation (15% for the Chesapeake plan and 8% in 2006 and 2005 and 6% in 2004 for the Nomac plan). The company contributed \$17.5 million, \$10.0 million and \$6.9 million to the Chesapeake plan in 2006, 2005 and 2004, respectively, and \$1.6 million, \$0.4 million and \$0.2 million to the Nomac plan in 2006, 2005 and 2004, respectively.

In November 2005, Chesapeake acquired Columbia Natural Resources, LLC, which sponsored the Columbia Natural Resources, LLC 401(k) Plan. Chesapeake's 401(k) plan was amended effective January 1, 2006 to honor previous service by employees with CNR and predecessor companies and was open to CNR employees in the Charleston, West Virginia headquarters office as well as exempt, administrative field employees. The CNR plan was adopted by the new employer entity, Chesapeake Appalachia, L.L.C., and was open to all non-administrative field employees, including union employees. The Company contributed \$0.6 million to this plan in 2006. Effective January 1, 2007, these employees, other than union employees, became eligible to participate in the Chesapeake plan. Union employees will continue participation in the CNR plan pending the outcome of ongoing labor negotiations.

We also maintain a 401(k) make-up plan and a deferred compensation plan, both of which are nonqualified deferred compensation plans. To be eligible to participate in the 401(k) make-up plan, an employee must receive annual compensation (base salary and bonus combined) of at least \$100,000 (\$95,000 in 2005 and \$90,000 in 2004), 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 matches 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 cash compensation. We contributed \$2.4 million, \$1.6 million and \$1.4 million to the 401(k) make-up plan during 2006, 2005 and 2004, respectively.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Employees with at least one year of service receiving an annual base salary of at least \$95,000 (\$100,000 in 2004) during the 12 months prior to the enrollment date are eligible to participate in our deferred compensation plan. In addition, non-employee directors are able to defer up to 100% of director fees. The maximum compensation that can be deferred by employees under all company deferred compensation plans, including the Chesapeake 401(k) plan, is a total of 75% of base salary and 100% of performance bonus. Chesapeake has made no matching or other contributions to the deferred compensation plan, although the plan permits the company to make discretionary contributions.

Any assets placed in trust by Chesapeake to fund future obligations of the 401(k) make-up plan and the deferred compensation plan 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.

Chesapeake maintains no post-employment benefit plans except those sponsored by Chesapeake Appalachia, L.L.C. As of December 31, 2006, a total of 188 employees were eligible for these plans. As of January 1, 2007, participation in these plans was limited to union members (135 employees) and continuing eligibility is the subject of ongoing labor negotiations. The Chesapeake Appalachia, L.L.C. benefit plans provide health care and life insurance benefits to eligible employees upon retirement. We account for these benefits on an accrual basis. As of December 31, 2006, the company had accrued \$2.8 million in accumulated post-employment benefit liability.

8. Major Customers and Segment Information

Sales to individual customers constituting 10% or more of total revenues (before the effects of hedging) were as follows:

Year Ended December 31,	Customer	Amount (\$ in thousands)	Percent of Total Revenues
2006	Eagle Energy Partners I, L.P.	\$867,276	16%
2005	Eagle Energy Partners I, L.P.	\$851,420	18%
2004	Eagle Energy Partners I, L.P.	\$467,387	17%

In September 2003, Chesapeake invested \$5.8 million in Eagle Energy Partners I, L.P. and received a 25% limited partnership interest. Through additional investments totaling \$27.1 million, Chesapeake has increased its limited partner ownership interest to \$32.9 million or approximately 33% as of December 31, 2006. 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 Statement of Financial Accounting Standards No. 131, *Disclosures about Segments of an Enterprise and Related Information*, we have two reportable operating segments. Our exploration and production segment and oil and natural gas marketing segment are managed separately because of the nature of their products and services. The exploration and production segment is responsible for finding and producing natural gas and crude oil. The marketing segment is responsible for gathering, processing, compressing, transporting and selling natural gas and crude oil primarily from Chesapeake-operated wells. We also have drilling rig and trucking operations, which were considered a part of the exploration and production segment prior to 2006. These service operations are responsible for providing drilling rigs primarily used on Chesapeake-operated wells and trucking services utilized in the transportation of drilling rigs on both Chesapeake-operated wells and wells operated by third parties.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Management evaluates the performance of our segments based upon income before income taxes. Revenues from the marketing segment's sale of oil and natural gas related to Chesapeake's ownership interests are reflected as exploration and production revenues. Such amounts totaled \$2.558 billion, \$2.396 billion and \$1.349 billion for 2006, 2005 and 2004, respectively. The following tables present selected financial information for Chesapeake's operating segments. Our drilling and trucking service operations are presented in "Other Operations" for all periods presented.

<u>For the Year Ended December 31, 2006:</u>	<u>Exploration and Production</u>	<u>Marketing</u>	<u>Other Operations</u>	<u>Intercompany Eliminations</u>	<u>Consolidated Total</u>
			(\$ in thousands)		
Revenues	\$ 5,618,894	\$ 4,134,495	\$ 324,777	\$(2,752,571)	\$ 7,325,595
Intersegment revenues	—	(2,558,104)	(194,467)	2,752,571	—
Total Revenues	5,618,894	1,576,391	130,310	—	7,325,595
Depreciation, depletion and amortization	1,440,454	9,955	27,997	(15,647)	1,462,759
Interest and other income	21,589	4,114	(240)	—	25,463
Interest expense	300,181	—	541	—	300,722
Other income/expense	117,396	—	—	—	117,396
INCOME BEFORE INCOME TAXES	\$ 3,191,563	\$ 40,931	\$ 106,395	\$ (83,530)	\$ 3,255,359
TOTAL ASSETS	\$23,333,306	\$ 863,917	\$ 786,243	\$ (566,299)	\$24,417,167
CAPITAL EXPENDITURES	\$ 8,423,551	\$ 254,987	\$ 230,940	\$ —	\$ 8,909,478
 <u>For the Year Ended December 31, 2005:</u>					
Revenues	\$ 3,272,585	\$ 3,788,653	\$ 60,755	\$(2,456,703)	\$ 4,665,290
Intersegment revenues	—	(2,395,948)	(60,755)	2,456,703	—
Total Revenues	3,272,585	1,392,705	—	—	4,665,290
Depreciation, depletion and amortization	939,904	5,097	5,897	(5,897)	945,001
Interest and other income	9,684	523	299	(54)	10,452
Interest expense	219,800	—	—	—	219,800
Other income/expense	70,419	—	—	—	70,419
INCOME BEFORE INCOME TAXES	\$ 1,466,652	\$ 26,496	\$ 10,089	\$ (9,844)	\$ 1,493,393
TOTAL ASSETS	\$15,123,840	\$ 688,747	\$ 305,875	\$ —	\$16,118,462
CAPITAL EXPENDITURES	\$ 7,696,400	\$ 132,817	\$ 69,945	\$ —	\$ 7,899,162
 <u>For the Year Ended December 31, 2004:</u>					
Revenues	\$ 1,936,176	\$ 2,122,235	\$ 22,864	\$(1,372,007)	\$ 2,709,268
Intersegment revenues	—	(1,349,143)	(22,864)	1,372,007	—
Total Revenues	1,936,176	773,092	—	—	2,709,268
Depreciation, depletion and amortization	602,894	8,428	3,775	(3,775)	611,322
Interest and other income	3,944	532	240	(240)	4,476
Interest expense	167,328	—	—	—	167,328
Other income/expense	24,557	—	—	—	24,557
INCOME BEFORE INCOME TAXES	\$ 801,583	\$ 3,343	\$ (1,995)	\$ 1,995	\$ 804,926
TOTAL ASSETS	\$ 7,810,772	\$ 318,246	\$ 115,491	\$ —	\$ 8,244,509
CAPITAL EXPENDITURES	\$ 3,845,851	\$ 42,462	\$ 23,957	\$ —	\$ 3,912,270

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

9. Stockholders' Equity, Restricted Stock and Stock Options

The following is a summary of the changes in our common shares outstanding for 2006, 2005 and 2004:

	<u>2006</u>	<u>2005</u>	<u>2004</u>
	(in thousands)		
Shares outstanding at January 1	375,511	316,941	221,856
Stock option and warrant exercises	6,969	3,996	2,952
Restricted stock issuances (net of forfeitures)	3,743	3,671	2,686
Preferred stock conversions/exchanges	12,252	18,703	43,447
Common stock issuances for cash	58,750	32,200	46,000
Common stock issued for the purchase of Chaparral Energy, Inc. common stock	1,376	—	—
Shares outstanding at December 31	<u>458,601</u>	<u>375,511</u>	<u>316,941</u>

The following is a summary of the changes in our preferred shares outstanding for 2006, 2005 and 2004:

	<u>6.75%</u>	<u>6.00%</u>	<u>5.00%</u> <u>(2003)</u>	<u>4.125%</u>	<u>5.00%</u> <u>(2005)</u>	<u>4.50%</u>	<u>5.00%</u> <u>(2005B)</u>	<u>6.25%</u>
	(in thousands)							
Shares outstanding at January 1, 2006	—	99	1,026	89	4,600	3,450	5,750	—
Preferred stock issuances	—	—	—	—	—	—	—	2,300
Conversion/exchange of preferred for common stock	—	(99)	(1,026)	(86)	—	—	—	—
Shares outstanding at December 31, 2006	<u>—</u>	<u>—</u>	<u>—</u>	<u>3</u>	<u>4,600</u>	<u>3,450</u>	<u>5,750</u>	<u>2,300</u>
Shares outstanding at January 1, 2005	—	103	1,725	313	—	—	—	—
Preferred stock issuances	—	—	—	—	4,600	3,450	5,750	—
Conversion/exchange of preferred for common stock	—	(4)	(699)	(224)	—	—	—	—
Shares outstanding at December 31, 2005	<u>—</u>	<u>99</u>	<u>1,026</u>	<u>89</u>	<u>4,600</u>	<u>3,450</u>	<u>5,750</u>	<u>—</u>
Shares outstanding at January 1, 2004	2,998	4,600	1,725	—	—	—	—	—
Preferred stock issuances	—	—	—	313	—	—	—	—
Conversion/exchange of preferred for common stock	(2,998)	(4,497)	—	—	—	—	—	—
Shares outstanding at December 31, 2004	<u>—</u>	<u>103</u>	<u>1,725</u>	<u>313</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>

In 2006, shares of our preferred stock were exchanged for or converted into common stock as follows:

- 221,898 shares of 5.0% (Series 2003) cumulative convertible preferred stock were exchanged for or converted into 1,375,670 shares of common stock in privately negotiated exchange transactions or pursuant to conversion rights;
- 804,048 shares of such 5.0% (Series 2003) cumulative convertible preferred stock were exchanged for 4,972,786 shares of common stock pursuant to a tender offer;

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

- 2,750 shares of 4.125% cumulative convertible preferred stock were exchanged for 172,594 shares of common stock in privately negotiated exchange transactions;
- 83,245 shares of such 4.125% cumulative convertible preferred stock were exchanged for 5,248,126 shares of common stock pursuant to a tender offer; and
- the remaining 99,310 shares of 6.0% cumulative convertible preferred stock were exchanged for or converted into 482,694 shares of common stock in privately negotiated exchange transactions or pursuant to conversion rights.

In 2005, 3,800 shares of 6.00% cumulative convertible preferred stock were converted into 18,468 shares of common stock, 699,054 shares of 5.00% (Series 2003) cumulative convertible preferred stock were exchanged into 4,362,720 shares of common stock and 224,190 shares of 4.125% cumulative convertible preferred stock were exchanged into 14,321,881 shares of common stock.

In 2004, 2,998,000 shares of 6.75% cumulative convertible preferred stock were converted into 19,467,482 shares of common stock, 600,000 shares of 6.0% cumulative convertible preferred stock were exchanged for 3,225,000 shares of common stock in a privately negotiated exchange transaction, and 3,896,890 shares of such 6.0% preferred stock were exchanged for 20,754,817 shares of common stock pursuant to a tender offer.

In connection with the exchanges noted above, we recorded a loss of \$10.6 million, \$26.9 million and \$36.7 million in 2006, 2005 and 2004, respectively. In general, the loss is equal to the excess of the fair value of all common stock exchanged over the fair value of the securities issuable pursuant to the original conversion terms of the preferred stock.

Dividends on our outstanding preferred stock are payable quarterly in cash or, with respect to our 6.25% mandatory convertible preferred stock and our 4.50% cumulative convertible preferred stock, we may pay dividends in cash, common stock or a combination thereof. Following is a summary of our preferred stock, including the primary conversion terms:

<u>Preferred Stock Series</u>	<u>Issue Date</u>	<u>Liquidation Preference per Share</u>	<u>Holder's Conversion Right</u>	<u>Initial Conversion Rate</u>	<u>Conversion Price</u>	<u>Company's Conversion Right From</u>	<u>Company's Market Conversion Trigger</u>
6.25% Mandatory Convertible (a)	June/July 2006	\$ 250	Any time	7.1715	\$ 34.86	Any time	\$52.29(b)
5.00% (Series 2005) Cumulative Convertible	April 2005	\$ 100	Any time	3.8811	\$25.766	April 15, 2010	\$33.50(c)
4.50% Cumulative Convertible	September 2005	\$ 100	Any time	2.2639	\$44.172	September 15, 2010	\$57.42(c)
5.00% (Series 2005B) Cumulative Convertible	November 2005	\$ 100	Any time	2.5595	\$ 39.07	November 15, 2010	\$50.79(c)
4.125% Cumulative Convertible	March/April 2004	\$1,000	Market price >\$21.65	60.0555	\$ 16.65	March 15, 2009	\$21.65(c)

- (a) Each share converts automatically on June 15, 2009 into 7.1715 to 8.6059 shares of common stock, depending on the common stock market price at the time.
- (b) Convertible at initial conversion rate plus cash equal to present value of future dividends to June 15, 2009.
- (c) Convertible at the Company's option if the Company's common stock equals or exceeds the trigger price for a specified time period.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Stock-Based Compensation Plans

Under Chesapeake's Long Term Incentive Plan, restricted stock, stock options, stock appreciation rights, performance shares and other stock awards may be awarded to employees, directors and consultants of Chesapeake. Subject to any adjustments as provided by the plan, the aggregate number of shares of common stock which may be issued under the plan may not exceed 7,000,000 shares. The maximum period for exercise of an option or stock appreciation right 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 or stock appreciation right on the date of grant. Awards granted under the plan become vested at dates or upon the satisfaction of certain performance or other criteria determined by a committee of the board of directors. No awards may be granted under this plan after September 30, 2014. This plan has been approved by our shareholders. Stock options to purchase 150,000 and 50,000 shares of our common stock were issued to our directors from this plan in 2005 and 2004, respectively. In addition, 75,000 and 62,500 shares of restricted stock were issued to our directors from this plan in 2006 and 2005, respectively. There were 2,610 restricted shares issued to employees during 2006 from this plan. As of December 31, 2006, there were 6.7 million shares remaining available for issuance under the plan.

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 awards may be granted under this plan after April 14, 2013. This plan has been approved by our shareholders. There were 4.0 million and 3.9 million restricted shares, net of forfeitures, issued during 2006 and 2005, respectively, from this plan. As of December 31, 2006, there were 59,000 shares remaining available for issuance under the 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. In each of 2006 and 2005, 10,000 shares of common stock were awarded to new directors from this plan. As of December 31, 2006, there are 20,000 shares remaining available for issuance under this plan. In January 2007, we awarded 10,000 shares of common stock to a new director from this plan.

Under Chesapeake's 2002 Non-Employee Director Stock Option Plan and 1992 Nonstatutory Stock Option Plan, we 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 covered a maximum of 500,000 shares and 3,132,000 shares, respectively. The 1992 plan terminated in December 2002 and the 2002 plan terminated in June 2005. 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 stock options outstanding to employees under a number of employee stock option plans which are described below. All outstanding options under these plans were at-the-money when granted, with an exercise price equal to the closing price of our common stock on the date of

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

grant and have a ten-year exercise period. These plans were terminated in June 2005 (with the exception of the 1994 plan which expired in October 2004) and therefore no shares remain available for stock option grants under the plans.

<u>Name of Plan</u>	<u>Eligible Participants</u>	<u>Type of Options</u>	<u>Shares Covered</u>	<u>Shareholder Approved</u>
2002 and 2001 Stock Option Plans	Employees and consultants	Incentive and nonqualified	3,000,000/ 3,200,000	Yes
2002 and 2001 Nonqualified Stock Option Plans	Employees and consultants	Nonqualified	4,000,000/ 3,000,000	No
2000 Employee and 1999 Stock Option Plans	Employees and consultants	Nonqualified	3,000,000 (each plan)	No
1996 and 1994 Stock Option Plans	Employees and consultants	Incentive and nonqualified	6,000,000 /4,886,910	Yes

Restricted Stock

Chesapeake began issuing shares of restricted common stock to employees in January 2004 and to non-employee directors in July 2005. The fair value of the awards issued is determined 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 for employees and three years for non-employee directors. 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 natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized in general and administrative expense or production expense. Note 1 details the accounting for our stock-based compensation expense in 2006, 2005 and 2004. As of December 31, 2005, the unamortized balance of unearned compensation recorded as a reduction of stockholders' equity was \$89.2 million. Upon adoption of SFAS 123(R) in January 2006, we eliminated the \$89.2 million of the unamortized balance of unearned compensation in stockholders' equity and reduced additional paid-in capital by the same amount on our consolidated balance sheet.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

A summary of the status of the unvested shares of restricted stock and changes during 2006, 2005 and 2004 is presented below:

	Number of Unvested Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2006	5,805,210	\$18.38
Granted	4,392,270	31.77
Vested	(2,818,249)	19.78
Forfeited	<u>(304,470)</u>	25.04
Unvested shares as of December 31, 2006	<u>7,074,761</u>	\$25.85
Unvested shares as of January 1, 2005	2,684,850	\$14.35
Granted	3,940,405	20.41
Vested	(739,255)	14.71
Forfeited	<u>(80,790)</u>	17.09
Unvested shares as of December 31, 2005	<u>5,805,210</u>	\$18.38
Unvested shares as of January 1, 2004	—	\$ —
Granted	2,714,900	14.35
Vested	(1,600)	14.16
Forfeited	<u>(28,450)</u>	14.29
Unvested shares as of December 31, 2004	<u>2,684,850</u>	\$14.35

The aggregate intrinsic value of restricted stock vested during 2006 was approximately \$86.1 million.

As of December 31, 2006, there was \$155.8 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of 2.73 years.

The vesting of certain restricted stock grants results in state and federal income tax benefits related to the difference between the market price of the common stock at the date of vesting and the date of grant. During the years ended December 31, 2006 and 2005, we recognized excess tax benefits related to restricted stock of \$4.3 million and \$2.0 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

Our President and Chief Operating Officer, Tom L. Ward, resigned as a director, officer and employee of the company effective February 10, 2006. Mr. Ward's Resignation Agreement provided for the immediate vesting of all of his unvested equity awards, which consisted of options to purchase 724,615 shares of Chesapeake's common stock at an average exercise price of \$8.01 per share and 1,291,875 shares of restricted common stock. As a result of this vesting, we incurred an expense of \$54.8 million in 2006.

Stock Options

We granted stock options prior to 2006 under several stock compensation plans. Outstanding options expire ten years from the date of grant and become exercisable over a four-year period.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The following table provides information related to stock option activity for 2006, 2005 and 2004:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value(a) (\$ in thousands)
Outstanding at January 1, 2006	20,256,013	\$ 6.14		
Exercised	(13,494,835)	5.34		\$352,369
Forfeited/ Canceled	(155,475)	20.22		
Outstanding at December 31, 2006	<u>6,605,703</u>	<u>\$ 7.43</u>	<u>5.36</u>	<u>\$142,829</u>
Exercisable at December 31, 2006	<u>5,337,153</u>	<u>\$ 7.02</u>	<u>5.14</u>	<u>\$117,583</u>
Shares authorized for future grants	<u>6,719,642</u>			
Fair value of options granted during period	\$ —			
Outstanding at January 1, 2005	24,228,464	\$ 6.00		
Granted	177,500	18.67		
Exercised	(4,032,180)	5.78		
Forfeited/ Canceled	(117,771)	8.51		
Outstanding at December 31, 2005	<u>20,256,013</u>	<u>\$ 6.14</u>		
Exercisable at December 31, 2005	<u>15,960,440</u>	<u>\$ 5.57</u>		
Shares authorized for future grants	<u>6,452,444</u>			
Fair value of options granted during period	\$ 6.21			
Outstanding at January 1, 2004	27,233,285	\$ 5.78		
Granted	347,250	14.23		
Exercised	(3,219,877)	4.94		
Forfeited/ Canceled	(132,194)	8.21		
Outstanding at December 31, 2004	<u>24,228,464</u>	<u>\$ 6.00</u>		
Exercisable at December 31, 2004	<u>15,441,511</u>	<u>\$ 5.06</u>		
Shares authorized for future grants	<u>8,392,285</u>			
Fair value of options granted during period	\$ 4.66			

(a) The intrinsic value of a stock option is the amount by which the current market value or the market value upon exercise of the underlying stock exceeds the exercise price of the option.

As of December 31, 2006, there was \$1.4 million of total unrecognized compensation cost related to unvested stock options. The cost is expected to be recognized over a weighted average period of 0.28 years.

During the years ended December 31, 2006, 2005 and 2004, we recognized excess tax benefits related to stock options of \$83.3 million, \$16.5 million and \$9.1 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

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The following table summarizes information about stock options outstanding at December 31, 2006:

Range of Exercise Prices	Outstanding Options			Options Exercisable	
	Number Outstanding	Weighted-Avg. Remaining Contractual Life	Weighted-Avg. Exercise Price	Number Exercisable	Weighted-Avg. Exercise Price
\$0.94 – \$ 4.00	743,646	2.69	\$ 2.51	743,646	\$ 2.51
4.06 – 4.06	58	1.45	4.06	58	4.06
5.20 – 5.20	771,827	5.56	5.20	771,827	5.20
5.35 – 5.89	446,890	3.99	5.58	446,890	5.58
6.11 – 6.11	1,175,478	4.75	6.11	1,175,478	6.11
6.13 – 7.74	216,479	4.75	6.91	216,479	6.91
7.80 – 7.80	1,133,174	6.02	7.80	544,262	7.80
7.86 – 10.01	231,901	5.62	8.50	200,609	8.53
10.08 – 10.08	1,337,097	6.48	10.08	789,904	10.08
10.10 – 22.49	549,153	7.20	14.08	448,000	14.50
<u>\$0.94 – \$22.49</u>	<u>6,605,703</u>	<u>5.36</u>	<u>\$ 7.43</u>	<u>5,337,153</u>	<u>\$ 7.02</u>

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 Natural Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of December 31, 2006, our oil and natural 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 natural 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 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.

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- 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.
- Basis protection swaps are arrangements that guarantee a price differential for oil or natural gas from a specified delivery point. For Mid-Continent basis protection swaps, which have negative differentials to NYMEX, 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 Appalachian Basin basis protection swaps, which have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater 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, 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. Generally, 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 natural gas prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and natural 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 counter-swaps are recorded as adjustments to oil and natural gas sales.

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

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Gains or losses from certain derivative transactions are reflected as adjustments to oil and natural gas sales on the consolidated statements of operations. Realized gains (losses) included in oil and natural gas sales were \$1.254 billion, (\$401.7) million and (\$154.9) million in 2006, 2005 and 2004, respectively. 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 natural gas sales. Unrealized gains (losses) included in oil and natural gas sales were \$495.5 million, \$41.1 million and \$40.9 million, in 2006, 2005 and 2004, 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 natural gas sales as unrealized gains (losses). Included in unrealized gains (losses) are gains (losses) on ineffectiveness of \$311.1 million, (\$76.3) million and (\$8.2) million in 2006, 2005 and 2004, respectively.

The estimated fair values of our oil and natural gas derivative instruments as of December 31, 2006 and 2005 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	December 31, 2006	December 31, 2005
	(\$ in thousands)	
Derivative assets (liabilities):		
Fixed-price natural gas swaps	\$ 1,075	\$(1,081,323)
Natural gas basis protection swaps	186,970	307,308
Fixed-price natural gas cap-swaps	121,866	(161,056)
Fixed-price natural gas counter-swaps	(5,455)	37,785
Natural gas call options (a)	(4,873)	(21,461)
Fixed-price natural gas collars	(6,922)	(9,374)
Floating-price natural gas swaps	—	2,607
Fixed-price oil swaps	28,149	(16,936)
Fixed-price oil cap-swaps	24,057	(3,364)
Estimated fair value	\$344,867	\$ (945,814)

(a) After adjusting for \$15.4 million and \$23.0 million of unrealized premiums, the cumulative unrealized gain related to these call options as of December 31, 2006 and 2005 was \$10.5 million and \$1.6 million, respectively.

Based upon the market prices at December 31, 2006, we expect to transfer approximately \$282.5 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to earnings during the next 12 months in the related month of production. All transactions hedged as of December 31, 2006 are expected to mature by December 31, 2009.

We have three secured hedging facilities maturing in 2011, each of which permits us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to a maximum value. Outstanding transactions under each facility are collateralized by certain of our oil and natural gas properties that do not secure any of our other obligations. The hedging facilities are subject to a 1% per annum exposure fee,

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which is assessed quarterly on the average of the daily negative fair market value amounts, if any, during the quarter. The hedging facilities contain the standard representations and default provisions that are typical of such agreements. The agreements also contain various restrictive provisions which govern the aggregate oil and natural gas production volumes that we are permitted to hedge under all of our agreements at any one time. The maximum permitted value of transactions under each facility and the fair market values of outstanding transactions are shown below.

	Secured Hedging Facilities		
	#1	#2	#3
	(\$ in thousands)		
Maximum permitted value of transactions under facility	\$750,000	\$500,000	\$500,000
Fair market value of outstanding transactions, as of			
December 31, 2006	\$ 34,403	\$ 59,639	\$ —
Fair market value of outstanding transactions, as of			
February 23, 2007	\$ 26,063	\$ 16,027	\$ 29,243

We assumed certain liabilities related to open derivative positions in connection with our acquisition of Columbia Natural Resources, LLC in November 2005. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of \$592 million. The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our oil and natural gas revenues upon settlement. For example, if the fair value of the derivative positions assumed does not change, then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to oil and natural gas revenues related to the derivative positions. If, however, the actual sales price is different from the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in oil and natural gas revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes at market prices on the date of our acquisition of CNR.

Pursuant to Statement of Financial Accounting Standards No. 149, *Amendment of SFAS 133 on Derivative Instruments and Hedging Activities*, the derivative instruments assumed in connection with the CNR acquisition are deemed to contain a significant financing element, and all cash flows associated with these positions are reported as financing activity in the statement of cash flows for the periods in which settlement occurs. The aggregate fair value of the remaining CNR derivatives as of December 31, 2006 was a liability of \$254.4 million.

In 2006, Chesapeake lifted a portion of its 2007, 2008 and 2009 hedges and as a result received \$744.1 million in cash from its hedging counterparties. The gain has been recorded in accumulated other comprehensive income and in oil and natural gas sales based on the designation of the hedges. For amounts initially recorded in other comprehensive income, the gain will be recognized in oil and natural gas sales in the month of the hedged production.

Interest Rate Derivatives

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 are recorded on the consolidated balance sheets as assets (liabilities), and the debt's carrying value amount is

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

Gains or losses from derivative transactions are reflected as adjustments to interest expense on the consolidated statements of operations. Realized gains (losses) included in interest expense were (\$1.9) million, \$4.9 million and \$0.8 million in 2006, 2005 and 2004, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as fair value 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 interest expense. Unrealized gains (losses) included in interest expense were \$1.6 million, \$1.6 million and (\$5.3) million in 2006, 2005 and 2004, respectively.

As of December 31, 2006, the following interest rate swaps used 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 (\$ in thousands)
September 2004 – August 2012	\$ 75,000,000	9.000%	6 month LIBOR plus 452 basis points	\$(2,695)
July 2005 – January 2015	\$150,000,000	7.750%	6 month LIBOR plus 289 basis points	(5,866)
July 2005 – June 2014	\$150,000,000	7.500%	6 month LIBOR plus 282 basis points	(6,133)
September 2005 – August 2014	\$250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	(6,807)
October 2005 – June 2015	\$200,000,000	6.375%	6 month LIBOR plus 112 basis points	(2,860)
October 2005 – January 2018	\$250,000,000	6.250%	6 month LIBOR plus 99 basis points	(6,334)
December 2006 – July 2013	\$250,000,000	7.625%	6 month LIBOR plus 266.5 basis points	(2,755)
				<u>\$(33,450)</u>

Subsequent to December 31, 2006, we entered into the following interest rate swaps (which qualify as fair value hedges) to convert a portion of our long-term fixed-rate debt to floating-rate debt:

Term	Notional Amount	Fixed Rate	Floating Rate
January 2007 – July 2013	\$250,000,000	7.625%	6 month LIBOR plus 251 basis points
January 2007 – August 2017	\$250,000,000	6.500%	6 month LIBOR plus 124.5 basis points

Additionally, subsequent to December 31, 2006, we sold call options to a counterparty with respect to these two interest rate swaps and received \$3.7 million in premiums. If exercised, the call option on the 7.625% interest rate swap gives the counterparty the right to terminate the interest rate swap on July 12, 2007 for a payment to Chesapeake of \$2.0 million. The call option on the 6.50% interest rate swap gives the counterparty the right to terminate the interest rate swap on August 15, 2007 for a payment of \$2.0 million to Chesapeake.

In 2006, we closed six interest rate swaps for gains totaling \$5.7 million. These interest rate swaps were designated as fair value hedges, and the settlement amounts received will be amortized as a reduction to realized interest expense over the remaining terms of the related senior notes. Subsequent to December 31, 2006, we closed one interest rate swap for a gain of \$1.0 million.

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Foreign Currency Derivatives

On December 5, 2006, we issued €600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the Euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties will pay Chesapeake €18.75 million and Chesapeake will pay the counterparties \$29.95 million, which will yield an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake €600 million and Chesapeake will pay the counterparties \$799.5 million. The terms of the cross currency swap were based on the dollar/euro exchange rate on the issuance date of \$1.3325 to €1.00. Through the cross currency swap, we have eliminated any potential variability in Chesapeake's expected cash flows related to changes in foreign exchange rates and therefore the swap qualifies as a cash flow hedge under SFAS 133. The euro-denominated debt is recorded in notes payable (\$791.8 million at December 31, 2006) using an exchange rate of \$1.3197 to €1.00. The cross currency swap is recorded on the consolidated balance sheet at a fair value of (\$18.9) million at December 31, 2006. The translation adjustment to notes payable is completely offset by the fair value of the cross currency swap and therefore there is no impact to the consolidated statement of operations. The remaining value of the cross currency swap related to future interest payments is reported in other comprehensive income.

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 values 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 financial instruments 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 and our convertible preferred stock using primarily quoted market prices. Our carrying amounts for such debt, excluding discounts or premiums related to interest rate derivatives, at December 31, 2006 and 2005 were \$7.215 billion and \$5.429 billion, respectively, compared to approximate fair values of \$7.336 billion and \$5.582 billion, respectively. The carrying amounts for our convertible preferred stock as of December 31, 2006 and 2005 were \$1.958 billion and \$1.577 billion, respectively, compared to approximate fair values of \$1.949 billion and \$1.686 billion, respectively.

Concentration of Credit Risk

A significant portion of our liquidity is concentrated in 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 receivable. 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. 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.

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11. Supplemental Disclosures About Oil And Natural Gas Producing Activities

Net Capitalized Costs

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

	December 31,	
	2006	2005
	(\$ in thousands)	
Oil and natural gas properties:		
Proved	\$21,949,295	\$15,880,919
Unproved	3,796,405	1,739,095
Total	25,745,700	17,620,014
Less accumulated depreciation, depletion and amortization	(5,291,846)	(3,945,703)
Net capitalized costs	\$20,453,854	\$13,674,311

Unproved properties not subject to amortization at December 31, 2006 and 2005 consisted mainly of leasehold acquired through corporate and significant oil and natural gas property acquisitions and through direct purchases of leasehold. We capitalized approximately \$179.1 million, \$79.0 million and \$36.2 million of interest during 2006, 2005 and 2004, 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.

Our ceiling test calculation as of December 31, 2006 indicated an impairment of our oil and natural gas properties of approximately \$500 million, net of income tax. However, natural gas prices subsequent to December 31, 2006 have improved sufficiently to eliminate this calculated impairment. As a result, we were not required to record a write-down of our oil and natural gas properties under the full-cost method of accounting in the fourth quarter of 2006. Based on spot prices for oil and natural gas as of December 31, 2006, cash flow hedges increased the full-cost ceiling by \$1.6 billion.

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Costs Incurred in Oil and Natural Gas Acquisition, Exploration and Development

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

	Years Ended December 31,		
	2006	2005	2004
	(\$ in thousands)		
Acquisition of properties:			
Proved properties	\$1,175,616	\$3,554,651	\$1,541,920
Unproved properties	2,855,848	1,375,675	570,495
Deferred income taxes	179,731	251,722	463,949
Total	4,211,195	5,182,048	2,576,364
Development costs:			
Development drilling (a)	2,772,149	1,566,730	863,268
Leasehold acquisition costs	616,550	290,946	110,530
Asset retirement obligation and other	23,214	52,619	41,924
Total	3,411,913	1,910,295	1,015,722
Exploration costs:			
Exploratory drilling	348,703	253,341	128,635
Geological and geophysical costs (b)	153,993	70,901	55,618
Total	502,696	324,242	184,253
Sales of oil and natural gas properties	(118)	(9,769)	(12,048)
Total	<u>\$8,125,686</u>	<u>\$7,406,816</u>	<u>\$3,764,291</u>

(a) Includes capitalized internal cost of \$147.3 million, \$94.1 million and \$45.4 million, respectively.

(b) Includes capitalized internal cost of \$13.3 million, \$8.1 million and \$6.3 million, respectively.

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

Chesapeake's results of operations from oil and natural gas producing activities are presented below for 2006, 2005 and 2004. The following table includes revenues and expenses associated directly with our oil and natural gas producing activities. It does not include any interest costs or general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our oil and natural gas operations.

	Years Ended December 31,		
	2006	2005	2004
	(\$ in thousands)		
Oil and natural gas sales (a)	\$ 5,618,894	\$3,272,585	\$1,936,176
Production expenses	(489,499)	(316,956)	(204,821)
Production taxes	(176,440)	(207,898)	(103,931)
Depletion and depreciation	(1,358,519)	(894,035)	(582,137)
Imputed income tax provision (b)	(1,383,858)	(676,599)	(376,303)
Results of operations from oil and natural gas producing activities	<u>\$ 2,210,578</u>	<u>\$1,177,097</u>	<u>\$ 668,984</u>

(a) Includes \$495.5 million, \$41.1 million and \$40.9 million of unrealized gains on oil and natural gas derivatives for the years ended December 31, 2006, 2005 and 2004, respectively.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

- (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 Natural Gas Reserve Quantities (unaudited)

Independent petroleum engineers and Chesapeake's petroleum engineers have evaluated our proved reserves. The portion of the proved reserves (by volume) evaluated by each for 2006, 2005 and 2004 is presented below.

	<u>Years ended December 31,</u>		
	<u>2006</u>	<u>2005</u>	<u>2004</u>
Netherland, Sewell & Associates, Inc.	32%	25%	23%
Data and Consulting Services, Division of Schlumberger Technology Corporation	16	16	—
Lee Keeling and Associates, Inc.	14	15	22
Ryder Scott Company L.P.	10	12	13
LaRoche Petroleum Consultants, Ltd.	8	8	10
H.J. Gruy and Associates, Inc.	—	2	6
Miller and Lents, Ltd.	—	—	1
Internal petroleum engineers	<u>20</u>	<u>22</u>	<u>25</u>
	<u>100%</u>	<u>100%</u>	<u>100%</u>

The information below on our oil and natural gas reserves 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 natural 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 natural 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 natural gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and natural 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Presented below is a summary of changes in estimated reserves of Chesapeake for 2006, 2005 and 2004:

	<u>Oil</u> (m bbl)	<u>Gas</u> (mmcf)	<u>Total</u> (mmcfe)
December 31, 2006			
Proved reserves, beginning of period	103,323	6,900,754	7,520,690
Extensions, discoveries and other additions	8,456	777,858	828,594
Revisions of previous estimates	(3,822)	539,606	516,676
Production	(8,654)	(526,459)	(578,383)
Sale of reserves-in-place	(3)	(123)	(141)
Purchase of reserves-in-place	<u>6,730</u>	<u>627,798</u>	<u>668,178</u>
Proved reserves, end of period	<u>106,030</u>	<u>8,319,434</u>	<u>8,955,614</u>
Proved developed reserves:			
Beginning of period	<u>76,238</u>	<u>4,442,270</u>	<u>4,899,694</u>
End of period	<u>76,705</u>	<u>5,113,211</u>	<u>5,573,441</u>
December 31, 2005			
Proved reserves, beginning of period	87,960	4,373,989	4,901,751
Extensions, discoveries and other additions	12,460	930,800	1,005,563
Revisions of previous estimates	(2,123)	53,950	41,204
Production	(7,698)	(422,389)	(468,577)
Sale of reserves-in-place	(26)	(332)	(486)
Purchase of reserves-in-place	<u>12,750</u>	<u>1,964,736</u>	<u>2,041,235</u>
Proved reserves, end of period	<u>103,323</u>	<u>6,900,754</u>	<u>7,520,690</u>
Proved developed reserves:			
Beginning of period	<u>62,713</u>	<u>2,842,141</u>	<u>3,218,418</u>
End of period	<u>76,238</u>	<u>4,442,270</u>	<u>4,899,694</u>
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	<u>29,694</u>	<u>959,299</u>	<u>1,137,463</u>
Proved reserves, end of period	<u>87,960</u>	<u>4,373,989</u>	<u>4,901,751</u>
Proved developed reserves:			
Beginning of period	<u>38,442</u>	<u>2,121,734</u>	<u>2,352,389</u>
End of period	<u>62,713</u>	<u>2,842,141</u>	<u>3,218,418</u>

During 2006, Chesapeake acquired approximately 668 bcfe of proved reserves through purchases of oil and natural gas properties for consideration of \$1.176 billion (primarily in 15 separate transactions of greater than \$10 million each). We also sold 0.1 bcfe of proved reserves for consideration of approximately \$0.1 million. During 2006, we recorded upward revisions of 517 bcfe to the December 31, 2005 estimates of our reserves. Included in the revisions were 212 bcfe of downward adjustments caused by lower natural gas prices at

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

December 31, 2006, offset by 729 bcfe of positive performance related revisions. Lower prices reduce the economic lives of the underlying oil and natural gas properties and thereby decrease the estimated future reserves. The weighted average oil and natural gas wellhead prices used in computing our reserves were \$56.25 per bbl and \$5.41 per mcf at December 31, 2006.

During 2005, Chesapeake acquired approximately 2.041 tcf of proved reserves through purchases of oil and natural gas properties for consideration of \$3.806 billion (primarily in 18 separate transactions of greater than \$10 million each). We also sold 0.5 bcfe of proved reserves for consideration of approximately \$9.8 million. During 2005, we recorded upward revisions of 41 bcfe to the December 31, 2004 estimates of our reserves. Approximately 24 bcfe of the upward revisions was caused by higher oil and natural gas prices at December 31, 2005. Higher prices extend the economic lives of the underlying oil and natural gas properties and thereby increase the estimated future reserves. The weighted average oil and natural gas wellhead prices used in computing our reserves were \$56.41 per bbl and \$8.76 per mcf at December 31, 2005.

During 2004, Chesapeake acquired approximately 1.137 tcf of proved reserves through purchases of oil and natural gas properties for consideration of \$2.006 billion (primarily in 15 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 natural gas prices at December 31, 2004. Higher prices extend the economic lives of the underlying oil and natural gas properties and thereby increase the estimated future reserves. The weighted average oil and natural gas wellhead prices used in computing our reserves were \$39.91 per bbl and \$5.65 per mcf at December 31, 2004.

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 natural 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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

	Years Ended December 31,		
	2006	2005	2004
	(\$ in thousands)		
Future cash inflows	\$ 50,984,435(a)	\$ 66,286,940(b)	\$ 28,245,336(c)
Future production costs	(13,790,630)	(14,794,530)	(6,542,219)
Future development costs	(6,803,715)	(4,676,287)	(2,115,511)
Future income tax provisions	(8,876,731)	(14,856,446)	(5,663,575)
Future net cash flows	21,513,359	31,959,677	13,924,031
Less effect of a 10% discount factor	(11,506,788)	(15,991,766)	(6,278,492)
Standardized measure of discounted future net cash flows	<u>\$ 10,006,571</u>	<u>\$ 15,967,911</u>	<u>\$ 7,645,539</u>

- (a) Calculated using weighted average prices of \$56.25 per barrel of oil and \$5.41 per mcf of natural gas.
- (b) Calculated using weighted average prices of \$56.41 per barrel of oil and \$8.76 per mcf of natural gas.
- (c) Calculated using weighted average prices of \$39.91 per barrel of oil and \$5.65 per mcf of natural gas.

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

	Years Ended December 31,		
	2006	2005	2004
	(\$ in thousands)		
Standardized measure, beginning of period (a)	\$ 15,967,911	\$ 7,645,539	\$ 5,326,753
Sales of oil and natural gas produced, net of production costs (b)	(3,203,804)	(3,108,277)	(1,741,438)
Net changes in prices and production costs	(10,953,623)	3,249,132	(730,020)
Extensions and discoveries, net of production and development costs	1,183,910	3,144,966	1,784,166
Changes in future development costs	(743,002)	(151,133)	33,284
Development costs incurred during the period that reduced future development costs	953,933	490,902	226,415
Revisions of previous quantity estimates	947,719	122,924	317,518
Purchase of reserves-in-place	1,134,615	6,252,030	2,580,973
Sales of reserves-in-place	(25)	(939)	(5,604)
Accretion of discount	2,293,359	1,050,439	733,314
Net change in income taxes	3,325,144	(4,106,833)	(852,462)
Changes in production rates and other	(899,566)	1,379,161	(27,360)
Standardized measure, end of period (a)	<u>\$ 10,006,571</u>	<u>\$ 15,967,911</u>	<u>\$ 7,645,539</u>

- (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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

12. Asset Retirement Obligations

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

	Years Ended December 31,	
	2006	2005
	(\$ in thousands)	
Asset retirement obligations, beginning of period	\$156,593	\$ 73,718
Additions	21,958	51,168
Revisions (a)	3,021	26,731
Settlements and disposals	(1,006)	(1,087)
Accretion expense	12,206	6,063
Asset retirement obligations, end of period	\$192,772	\$156,593

(a) Based on increasing service costs, we revised our asset retirement obligation related to oil and natural gas wells in 2006 and 2005.

13. Acquisitions and Investments

Oil and Natural Gas Properties

Through multiple purchases completed in 2006, we invested \$1.355 billion in proved properties, including approximately \$179.7 million of deferred income taxes to reflect the tax effect of the cost paid in excess of the tax basis acquired on certain corporate acquisitions. Additionally we invested \$2.856 billion in unproved property acquisitions.

On November 14, 2005, Chesapeake completed its acquisition of Columbia Natural Resources, LLC ("CNR"), an Appalachian Basin natural gas producer with properties principally located in West Virginia, Kentucky, Ohio, Pennsylvania and New York. The cash purchase price totaled \$2.2 billion and was allocated based on the fair values of the assets and liabilities acquired at the date of acquisition. The acquisition was accounted for using the purchase method of accounting and has been included in the consolidated financial statements of Chesapeake since the date of acquisition.

The purchase price paid for CNR was allocated as follows (\$ in thousands):

Current assets	\$ 73,637
Evaluated oil and natural gas properties	2,368,726
Unevaluated properties	500,000
Other assets	178,431
Current liabilities	(185,003)
Derivative liability	(591,756)
Asset retirement obligation	(39,528)
Deferred taxes	(3,293)
Credit facility payoff	(96,116)
Other long-term deferred liabilities	(5,098)
Net cash consideration	\$2,200,000

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The pro forma information below is presented for illustrative purposes only and is based on estimates and assumptions deemed appropriate by Chesapeake. The pro forma information should not be relied upon as an indication of the operating results that Chesapeake would have achieved if the acquisition had occurred at the beginning of each period presented, or of Chesapeake's results after the CNR acquisition. The pro forma information for the years ended December 31, 2005 and 2004 reflect the CNR acquisition as if the acquisition occurred on January 1, 2004.

	Years Ended December 31,	
	2005	2004
	(\$ in millions, except per share amounts)	
Revenues	\$4,847.4	\$2,913.6
Income from continuing operations	\$1,758.5	\$ 979.0
Net income available to common shareholders	\$ 829.9	\$ 390.3
Income per Common Share:		
Basic	\$ 2.41	\$ 1.41
Diluted	\$ 2.23	\$ 1.28

Drilling Rigs and Oilfield Trucks

In January 2006, we acquired a privately-owned Oklahoma-based oilfield trucking service company for \$47.5 million. In addition to the cash purchase price, we recorded approximately \$10.7 million of deferred income taxes to reflect the tax effect of the cost paid in excess of the tax basis acquired in connection with this acquisition. Of the total \$58.2 million purchase price, \$27.3 million was allocated to tangible equipment, \$11.0 million to intangibles and \$19.9 million to goodwill. The amounts allocated to intangibles and goodwill are included in long-term assets in the accompanying consolidated balance sheet. Goodwill is not amortized but is subject to an annual assessment of impairment. In February 2006, we acquired 13 drilling rigs and related assets through our wholly owned subsidiary, Nomac Drilling Corporation, from Martex Drilling Company, L.L.P., a privately-owned drilling contractor with operations in East Texas and North Louisiana, for \$150 million. In July 2006, we acquired 15 rigs and related trucking assets from a drilling contractor in the Appalachian Basin for approximately \$70 million in cash.

Acquisitions were recorded using the purchase method of accounting and, accordingly, results of operations of these acquired activities and assets have been included in Chesapeake's results of operations from the respective closing dates of the acquisitions.

Investments

In August 2006, we invested \$254 million to acquire a 19.9% interest in a privately-held provider of well stimulation and high pressure pumping services, with operations currently focused in Texas (principally in the Fort Worth Barnett Shale) and the Rocky Mountains. In September 2006, we acquired 32% of the outstanding common stock of Chaparral Energy, Inc. for \$240 million in cash and 1,375,989 newly issued shares of our common stock valued at \$40 million. Chaparral is a privately-held independent oil and natural gas company headquartered in Oklahoma City, Oklahoma. In 2006, we sold our investment in publicly-traded Pioneer Drilling Company ("Pioneer") common stock, realizing proceeds of \$158.9 million and a gain of \$117.4 million. We owned 17% of the common stock of Pioneer, which we began acquiring in 2003.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

14. Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 2006 and 2005 are as follows (\$ in thousands except per share data):

	Quarters Ended			
	March 31, 2006	June 30, 2006	September 30, 2006	December 31, 2006
Total revenues	\$1,944,567	\$1,584,016	\$1,924,411	\$1,867,601
Gross profit (a)	951,632	673,164	953,389	835,037
Net income	623,723(b)	359,903	548,335	471,362
Net earnings per common share:				
Basic	\$ 1.64	\$ 0.87	\$ 1.25	\$ 1.05
Diluted	\$ 1.44	\$ 0.82	\$ 1.13	\$ 0.96

	Quarters Ended			
	March 31, 2005	June 30, 2005	September 30, 2005	December 31, 2005
Total revenues	\$ 783,450	\$1,048,018	\$1,082,843	\$1,750,979
Gross profit (a)	237,537	425,463	335,634	774,526
Net income	125,010(c)	193,779(d)	176,988(e)	452,525(f)
Net earnings per common share:				
Basic	\$ 0.39	\$ 0.58	\$ 0.46	\$ 1.25
Diluted	\$ 0.36	\$ 0.52	\$ 0.43	\$ 1.11

(a) Total revenue less operating costs.

(b) Includes a pre-tax employee retirement expense of \$54.8 million and a pre-tax gain on sale of investment of \$117.4 million.

(c) Includes a pre-tax loss on repurchases and exchanges of debt of \$0.9 million.

(d) Includes a pre-tax loss on repurchases and exchanges of debt of \$68.4 million.

(e) Includes a pre-tax loss on repurchases and exchanges of debt of \$0.7 million.

(f) Includes a pre-tax loss on repurchases and exchanges of debt of \$0.4 million.

15. Recently Issued Accounting Standards

The Financial Accounting Standards Board (FASB) recently issued the following standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

In December 2004, the FASB 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. We adopted this statement effective January 1, 2006. The effect of SFAS 123(R) is more fully described in Note 1.

In September 2005, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*. EITF Issue No. 04-13 requires that purchases and sales of inventory with the same counterparty in the same line of business should be accounted for as a single non-monetary exchange, if entered into in contemplation of one another. The consensus is effective for inventory arrangements entered into, modified or renewed in interim or annual reporting periods beginning after March 15, 2006. We adopted this issue effective April 1, 2006. The adoption of EITF Issue No. 04-13 did not have a material impact on our financial statements.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

In June 2006, the FASB issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109*. FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS 109, *Accounting for Income Taxes*. FIN 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. FIN 48 is effective for fiscal years beginning after December 15, 2006. Based on our evaluation as of December 31, 2006, we do not expect that FIN 48 will have a material impact on our financial position, results of operations or cash flows.

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments—an amendment of FASB Statements No. 133 and 140*. SFAS 155 permits an entity to measure at fair value any financial instrument that contains an embedded derivative that otherwise would require bifurcation. This statement is effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after September 15, 2006. We are currently evaluating the provisions of SFAS 155 and believe that adoption will not have a material effect on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. We are currently assessing the impact, if any, SFAS 157 and believe that adoption will not have a material effect on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*. This statement requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. This statement is effective as of the end of the fiscal year ending after December 15, 2006. SFAS 158 did not have a material impact on our financial position, results of operations or cash flows.

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

Description	Balance at Beginning of Period	Additions		Deductions	Balance at End of Period
		Charged To Expense	Charged To Other Accounts		
December 31, 2006:					
Allowance for doubtful accounts	\$4,904	\$626	\$ 18	\$ —	\$5,548
Valuation allowance for deferred tax assets	\$ —	\$—	\$ —	\$ —	\$ —
December 31, 2005:					
Allowance for doubtful accounts	\$4,648	\$114	\$ 142	\$ —	\$4,904
Valuation allowance for deferred tax assets	\$ —	\$—	\$ —	\$ —	\$ —
December 31, 2004:					
Allowance for doubtful accounts	\$2,669	\$975	\$1,004	\$ —	\$4,648
Valuation allowance for deferred tax assets				\$	
	\$6,805	\$—	\$ —	6,805(a)	\$ —

- (a) As of December 31, 2004, we determined that it is more likely than not that the \$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, 2006, 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 as of December 31, 2006, 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, 2006 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*

Not applicable.

PART III

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

The information called for by this Item 10 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 30, 2007.

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 30, 2007.

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 30, 2007.

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 30, 2007.

ITEM 14. *Principal Accountant 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 30, 2007.

PART IV

ITEM 15. Exhibits and 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:

<u>Exhibit Number</u>	<u>Description</u>
3.1.1	Chesapeake's Restated Certificate of Incorporation, as amended. Incorporated herein by reference to Exhibit 3.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.2	Certificate of Designation for Series A Junior Participating Preferred Stock, as amended. Incorporated herein by reference to Exhibit 3.1.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.3	Certificate of Designation of 4.125% Cumulative Convertible Preferred Stock, as amended. Incorporated herein by reference to Exhibit 3.1.4 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.4	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B). Incorporated herein by reference to Exhibit 3.1 to Chesapeake's current report on Form 8-K filed November 9, 2005.
3.1.5	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005), as amended. Incorporated herein by reference to Exhibit 3.1.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2005.
3.1.6	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock. Incorporated herein by reference to Exhibit 3.1 to Chesapeake's current report on Form 8-K filed September 15, 2005.
3.1.7	Certificate of Designation of 6.25% Mandatory Convertible Preferred Stock. Incorporated herein by reference to Exhibit 3.1 to Chesapeake's current report on Form 8-K dated June 30, 2006.
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 Trust Company, N.A., 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. Third Supplemental Indenture dated as of January 31, 2005. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2004. Fourth Supplemental Indenture dated as of July 15, 2005. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2005. Fifth Supplemental Indenture dated as of

**Exhibit
Number**

Description

- November 14, 2005. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Sixth Supplemental Indenture dated as of February 24, 2006. Incorporated herein by reference to Exhibit 4.1.2 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Seventh Supplemental Indenture dated as of May 8, 2006. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Eighth Supplemental Indenture dated as of October 18, 2006. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
- 4.1.1* Ninth Supplemental Indenture dated as of February 9, 2007 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 Trust Company, N.A., 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 Trust Company, N.A., 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. Third Supplemental Indenture dated as of January 31, 2005. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2004. Fourth Supplemental Indenture dated as of July 15, 2005. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2005. Fifth Supplemental Indenture dated as of November 14, 2005. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Sixth Supplemental Indenture dated as of February 24, 2006. Incorporated herein by reference to Exhibit 4.2.2 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Seventh Supplemental Indenture dated as of May 8, 2006. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Eighth Supplemental Indenture dated as of October 18, 2006. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
- 4.2.1* Ninth Supplemental Indenture dated as of February 9, 2007 to Indenture dated as of August 2, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.00% senior notes due 2014.
- 4.3 Indenture dated as of December 20, 2002 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 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

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- 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. Seventh Supplemental Indenture dated as of January 31, 2005. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2004. Eighth Supplemental Indenture dated as of July 15, 2005. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2005. Ninth Supplemental Indenture dated as of November 14, 2005. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Tenth Supplemental Indenture dated as of February 24, 2006. Incorporated herein by reference to Exhibit 4.3.2 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Eleventh Supplemental Indenture dated as of May 8, 2006. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Twelfth Supplemental Indenture dated as of October 18, 2006. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
- 4.3.1* Thirteenth Supplemental Indenture dated February 9, 2007 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 Trust Company, N.A., as Trustee, with respect to 7.75% Senior Notes due 2015.
- 4.4 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.
- 4.5 Sixth Amended and Restated Credit Agreement, dated as of February 3, 2006, among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., as Co-Borrowers, Union Bank of California, N.A., as Administrative Agent, BNP Paribas, as Syndication Agent, Bank of America, N.A., 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 8, 2006.
- 4.6 Indenture dated as of March 5, 2003 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 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. Sixth Supplemental Indenture dated January 31, 2005. Incorporated herein by reference to Exhibit 4.9.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2004. Seventh Supplemental Indenture dated July 15, 2005. Incorporated herein by reference to Exhibit 4.9.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2005. Eighth Supplemental Indenture dated November 14, 2005. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Ninth Supplemental Indenture dated February 24, 2006. Incorporated herein by reference to Exhibit 4.6.2 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Tenth Supplemental Indenture dated May 8, 2006. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Eleventh Supplemental Indenture dated October 18, 2006. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.

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4.6.1*	Twelfth Supplemental Indenture dated February 9, 2007 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 Trust Company, N.A., as Trustee, with respect to 7.5% Senior Notes due 2013.
4.7	Indenture dated as of November 26, 2003 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 6.875% 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. Fourth Supplemental Indenture dated as of January 31, 2005. Incorporated herein by reference to Exhibit 4.10.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2004. Fifth Supplemental Indenture dated July 15, 2005. Incorporated herein by reference to Exhibit 4.10.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2005. Sixth Supplemental Indenture dated as of November 14, 2005. Incorporated herein by reference to Exhibit 4.7.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Seventh Supplemental Indenture dated as of February 24, 2006. Incorporated herein by reference to Exhibit 4.7.2 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Eighth Supplemental Indenture dated May 8, 2006. Incorporated herein by reference to Exhibit 4.7.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Ninth Supplemental Indenture dated October 18, 2006. Incorporated herein by reference to Exhibit 4.7.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
4.7.1*	Tenth Supplemental Indenture dated February 9, 2007 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 Trust Company, N.A., as Trustee, with respect to 6.875% senior notes due 2016.
4.8	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. 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. First Supplemental Indenture dated January 31, 2005. Incorporated herein by reference to Exhibit 4.11.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2004. Second Supplemental Indenture dated May 13, 2005. Incorporated herein by reference to Exhibit 4.11.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2005. Third Supplemental Indenture dated July 15, 2005. Incorporated by reference herein to Exhibit 4.11.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2005. Fourth Supplemental Indenture dated November 14, 2005. Incorporated herein by reference to Exhibit 4.8.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Fifth Supplemental Indenture dated February 24, 2006. Incorporated herein by reference to Exhibit 4.8.2 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Sixth Supplemental Indenture dated May 8, 2006. Incorporated by reference herein to Exhibit 4.8.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Seventh Supplemental Indenture dated October 18, 2006. Incorporated by reference herein to Exhibit 4.8.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
4.8.1*	Eighth Supplemental Indenture dated February 9, 2007 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.

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- 4.9 Indenture dated as of April 19, 2005 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 6.625% senior notes due 2016. Incorporated herein by reference to Exhibit 4.12 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2005. First Supplemental Indenture dated as of July 15, 2005. Incorporated herein by reference to Exhibit 4.12.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2005. Second Supplemental Indenture dated as of November 14, 2005. Incorporated herein by reference to Exhibit 4.9.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Third Supplemental Indenture dated as of February 24, 2006. Incorporated herein by reference to Exhibit 4.9.2 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Fourth Supplemental Indenture dated as of May 8, 2006. Incorporated herein by reference to Exhibit 4.9.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Fifth Supplemental Indenture dated as of October 18, 2006. Incorporated herein by reference to Exhibit 4.9.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
- 4.9.1* Sixth Supplemental Indenture dated as of February 9, 2007 to Indenture dated as of April 19, 2005 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 6.625% senior notes due 2016.
- 4.10 Indenture dated as of June 20, 2005 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 6.25% senior notes due 2018. Incorporated herein by reference to Exhibit 4.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2005. First Supplemental Indenture dated as of November 14, 2005. Incorporated herein by reference to Exhibit 4.10.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Second Supplemental Indenture dated as of February 24, 2006. Incorporated herein by reference to Exhibit 4.10.2 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Third Supplemental Indenture dated as of May 8, 2006. Incorporated herein by reference to Exhibit 4.10.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Fourth Supplemental Indenture dated as of October 18, 2006. Incorporated herein by reference to Exhibit 4.10.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
- 4.10.1* Fifth Supplemental Indenture dated as of February 9, 2007 to Indenture dated as of June 20, 2005 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 6.25% senior notes due 2018.
- 4.11 Indenture dated as of August 16, 2005 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 6.50% senior notes due 2017. Incorporated herein by reference to Exhibit 4.1 to Chesapeake's current report on Form 8-K dated August 16, 2005. First Supplemental Indenture dated as of November 14, 2005. Incorporated herein by reference to Exhibit 4.11.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Second Supplemental Indenture dated as of February 1, 2006. Incorporated herein by reference to Exhibit 4.11.2 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Third Supplemental Indenture dated as of February 24, 2006. Incorporated herein by reference to Exhibit 4.11.3 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005. Fourth Supplemental Indenture dated as of May 8, 2006. Incorporated herein by reference to Exhibit 4.11.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Fifth Supplemental Indenture dated as of October 18, 2006. Incorporated herein by reference to Exhibit 4.11.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
- 4.11.1* Sixth Supplemental Indenture dated as of February 9, 2007 to Indenture dated as of August 16, 2005 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 6.50% senior notes due 2017.

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4.12	Indenture dated as of November 8, 2005 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 6.875% senior notes due 2020. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's current report on Form 8-K dated November 8, 2005. First Supplemental Indenture dated as of November 14, 2005. Incorporated herein by reference to Exhibit 4.3 to Chesapeake's registration statement on Form S-4 (No. 333-132263). Second Supplemental Indenture dated as of February 24, 2006. Incorporated herein by reference to Exhibit 4.4 to Chesapeake's registration statement on Form S-4 (No. 333-132263). Third Supplemental Indenture dated as of May 8, 2006. Incorporated herein by reference to Exhibit 4.12.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Fourth Supplemental Indenture dated as of October 18, 2006. Incorporated herein by reference to Exhibit 4.12.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
4.12.1*	Fifth Supplemental Indenture dated as of February 9, 2007 to Indenture dated as of November 8, 2005 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 6.875% senior notes due 2020.
4.13	Indenture dated as of November 8, 2005 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 2.75% contingent convertible senior notes due 2035. Incorporated herein by reference to Exhibit 4.1.2 to Chesapeake's current report on Form 8-K dated November 8, 2005. First Supplemental Indenture dated as of November 14, 2005. Incorporated herein by reference to Exhibit 4.5 to Chesapeake's registration statement on Form S-3 (No. 333-132261). Second Supplemental Indenture dated as of February 24, 2006. Incorporated herein by reference to Exhibit 4.6 to Chesapeake's registration statement on Form S-3 (No. 333-132261). Third Supplemental Indenture dated as of May 8, 2006. Incorporated herein by reference to Exhibit 4.13.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006. Fourth Supplemental Indenture dated as of October 18, 2006. Incorporated herein by reference to Exhibit 4.13.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
4.13.1*	Fifth Supplemental Indenture dated as of February 9, 2007 to Indenture dated as of November 8, 2005 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 2.75% contingent convertible senior notes due 2035.
4.14	Indenture dated as of June 30, 2006 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 7.625% senior notes due 2013. Incorporated herein by reference to Exhibit 4.1 to Chesapeake's current report on Form 8-K dated June 30, 2006. First Supplemental Indenture dated as of October 18, 2006. Incorporated herein by reference to Exhibit 4.14.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
4.14.1*	Second Supplemental Indenture dated as of February 9, 2007 to Indenture dated as of June 30, 2006 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 7.625% senior notes due 2013.
4.15	Indenture dated as of December 6, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, The Bank of New York Trust Company, N.A., as Trustee, AIB/BNY Fund Management (Ireland) Limited, as Irish Paying Agent and Transfer Agent, and The Bank of New York, London Branch, as Registrar, Transfer Agent and Paying Agent, with respect to 6.25% senior notes due 2017. Incorporated herein by reference to Exhibit 4.1 to Chesapeake's current report on Form 8-K dated December 6, 2006.

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4.15.1*	First Supplemental Indenture dated as of February 9, 2007 to Indenture dated as of December 6, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, The Bank of New York Trust Company, N.A., as Trustee, AIB/BNY Fund Management (Ireland) Limited, as Irish Paying Agent and Transfer Agent, and The Bank of New York, London Branch, as Registrar, Transfer Agent and Paying Agent, with respect to 6.25% senior notes due 2017.
10.1.1†	Chesapeake's 2003 Stock Incentive Plan, as amended. Incorporated herein by reference to Exhibit 10.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
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 September 30, 2006.
10.1.4†	Chesapeake's 1996 Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.4 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
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, as amended. Incorporated herein by reference to Exhibit 10.1.5 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
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, as amended. Incorporated herein by reference to Exhibit 10.1.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
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.
10.1.8†	Chesapeake's 2001 Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.8 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
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.
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.

<u>Exhibit Number</u>	<u>Description</u>
10.1.10†	Chesapeake's 2001 Nonqualified Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.10 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
10.1.11†	Chesapeake's 2002 Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.11 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
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, as amended. Incorporated herein by reference to Exhibit 10.1.13 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2006.
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. Incorporated herein by reference to Exhibit 10.1.15.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2004.
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. Incorporated herein by reference to Exhibit 10.1.16.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2004.
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.
10.1.18†*	Chesapeake's Long Term Incentive Plan, as amended.
10.1.18.1†	Form of Non-Employee Director Stock Option Agreement for the Long Term Incentive Plan. Incorporated herein by reference to Exhibit 10.1.18.1 to Chesapeake's current report on Form 8-K dated June 16, 2005.

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10.1.18.2†	Form of Restricted Stock Award Agreement for the Long Term Incentive Plan. Incorporated herein by reference to Exhibit 10.1.18.2 to Chesapeake's current report on form 8-K dated June 16, 2005.
10.1.18.3†	Form of Non-Employee Director Restricted Stock Award Agreement for the Long Term Incentive Plan. Incorporated herein by reference to Exhibit 10.1.18.3 to Chesapeake's current report on Form 8-K dated June 16, 2005.
10.1.19†	Founder Well Participation Program. Incorporated herein by reference to Exhibit B to Chesapeake's definitive proxy statement for its 2005 annual meeting of shareholders filed April 29, 2005.
10.2.1†	Sixth Amended and Restated Employment Agreement dated as of January 1, 2007, between Aubrey K. McClendon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.1 to Chesapeake's current report on Form 8-K dated December 20, 2006.
10.2.2†	Employment Agreement dated as of October 1, 2006 between Marcus C. Rowland and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.2 to Chesapeake's current report on Form 8-K filed October 5, 2006.
10.2.3†	Employment Agreement dated as of October 1, 2006 between Steven C. Dixon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.3 to Chesapeake's current report on Form 8-K filed October 5, 2006.
10.2.4†	Employment Agreement dated as of October 1, 2006 between J. Mark Lester and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.4 to Chesapeake's current report on Form 8-K filed October 5, 2006.
10.2.5†*	Employment Agreement dated as of January 1, 2007 between Douglas J. Jacobson and Chesapeake Energy Corporation.
10.2.6†	Employment Agreement dated as of January 1, 2007 between Martha A. Burger and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.2 to Chesapeake's current report on Form 8-K filed December 20, 2006.
10.2.7†	Employment Agreement dated as of October 1, 2006 between Henry J. Hood and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.7 to Chesapeake's current report on Form 8-K filed October 5, 2006.
10.2.8†	Employment Agreement dated as of October 1, 2006 between Michael A. Johnson and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.8 to Chesapeake's current report on Form 8-K filed October 5, 2006.
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. Incorporated herein by reference to Exhibit 10.4 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2006.
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. Amendment No. 2 dated March 3, 2006. Incorporated herein by reference to Exhibit 10.6.1 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005.

<u>Exhibit Number</u>	<u>Description</u>
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 Netherland, Sewell & Associates, Inc.
23.3*	Consent of Data & Consulting Services, Division of Schlumberger Technology Corporation
23.4*	Consent of Lee Keeling and Associates, Inc.
23.5*	Consent of Ryder Scott Company L.P.
23.6*	Consent of LaRoche Petroleum Consultants, 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 1, 2007

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.

<u>Signature</u>	<u>Capacity</u>	<u>Date</u>
/s/ AUBREY K. McCLENDON Aubrey K. McClendon	Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)	March 1, 2007
/s/ MARCUS C. ROWLAND Marcus C. Rowland	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 1, 2007
/s/ MICHAEL A. JOHNSON Michael A. Johnson	Senior Vice President— Accounting, Controller and Chief Accounting Officer (Principal Accounting Officer)	March 1, 2007
/s/ RICHARD K. DAVIDSON Richard K. Davidson	Director	March 1, 2007
/s/ FRANK KEATING Frank Keating	Director	March 1, 2007
/s/ BREENE M. KERR Breene M. Kerr	Director	March 1, 2007
/s/ CHARLES T. MAXWELL Charles T. Maxwell	Director	March 1, 2007
/s/ MERRILL A. MILLER, JR Merrill A. Miller, Jr.	Director	March 1, 2007
/s/ DON NICKLES Don Nickles	Director	March 1, 2007
/s/ FREDERICK B. WHITTEMORE Frederick B. Whittemore	Director	March 1, 2007



Chesapeake Energy Corporation

6100 North Western Avenue

Oklahoma City, Oklahoma 73118

www.chkenergy.com

