CHESAPEAKE ENERGY CORP
Form 10-K
February 29, 2008

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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the Fiscal Year Ended December 31, 2007

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

(405) 848-8000

Registrant s telephone number, including area code

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

Title of Each Class	**Name of Each Exchange on Which Registered**
Common Stock, par value $.01	New York Stock Exchange

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
2.5% Contingent Convertible Senior Notes due 2037	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 x 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 x

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 x 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. x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer x Accelerated Filer ¨ Non-accelerated Filer ¨ Smaller Reporting Company ¨

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

The aggregate market value of our common stock held by non-affiliates on June 29, 2007 was approximately $12.1 billion. At February 26, 2008, there were 514,009,781 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2008 Annual Meeting of Shareholders are incorporated by reference in Part III.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

2007 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 (first among independents). We own interests in approximately 38,500 producing oil and natural gas wells that are currently producing approximately 2.2 billion cubic feet equivalent, or bcfe, per day, 92% of which is natural gas. Our strategy is focused on discovering, acquiring and developing conventional and unconventional natural gas reserves onshore in the U.S., east of the Rocky Mountains.

Our most important operating area has historically been the *Mid-Continent region* of Oklahoma, Arkansas, southwestern Kansas and the Texas Panhandle. At December 31, 2007, 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, Pennsylvania 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 unconventional play onshore in the U.S. east of the Rockies, including the Barnett Shale, the Arkansas Fayetteville Shale, the Appalachian Basin Devonian and Marcellus Shales, the Arkoma and Ardmore Basin Woodford Shale in Oklahoma, the Delaware Basin Barnett and Woodford Shales in West Texas, and the Alabama Conasauga and Chattanooga Shales.

As of December 31, 2007, we had 10.879 trillion cubic feet equivalent, or tcfe, of proved reserves, of which 93% were natural gas and all of which were onshore. During 2007, we produced an average of 1.957 bcfe per day, a 23% increase over the 1.585 bcfe per day produced in 2006. We replaced our 714 bcfe of production with an internally estimated 2.637 tcfe of new proved reserves for a reserve replacement rate of 369%. Reserve replacement through the drillbit was 2.468 tcfe, or 346% of production (including 1.248 tcfe of positive performance revisions, of which 1.207 tcfe relates to infill drilling and increased density locations, and 97 bcfe of positive revisions resulting from oil and natural gas price increases between December 31, 2006 and December 31, 2007), and reserve replacement through acquisitions was 377 bcfe, or 53% of production. During 2007, we divested 208 bcfe of proved reserves. As a result, our proved reserves grew by 21% during 2007, from 9.0 tcfe to 10.9 tcfe. Of our 10.9 tcfe of proved reserves, 64% were proved developed reserves.

During 2007, Chesapeake continued the industry s most active drilling program and drilled 1,992 gross (1,695 net) operated wells and participated in another 1,679 gross (224 net) wells operated by other companies. The company s drilling success rate was 99% for company-operated wells and 97% for non-operated wells. Also during 2007, we invested $4.3 billion in operated wells (using an average of 140 operated rigs) and $708 million in non-operated wells (using an average of 105 non-operated rigs). Total costs incurred in oil and natural gas acquisition, exploration and development activities during 2007, including seismic, unproved properties, leasehold, capitalized interest and internal costs, non-cash tax basis step-up and asset retirement obligations, were $7.6 billion.

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.chk.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.

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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 ten years, our strategy to accomplish this goal has been to focus onshore in the U.S. east of the Rockies, where we believe we can generate the most attractive risk adjusted returns. In building our industry-leading resource base during the period from 1998 to 2007, we integrated an aggressive and technologically-advanced drilling program with an active property consolidation program focused on small to medium-sized corporate and property acquisitions. During the past two years, we have shifted our strategy from drilling inventory capture to drilling inventory conversion. In doing so, we have de-emphasized acquisitions of proved properties while further emphasizing our industry-leading drilling program and converting our substantial backlog of drilling opportunities into proved developed producing reserves. Key elements of this business strategy are further explained below.

Grow through the Drillbit. We believe that our most distinctive characteristic is our commitment and ability to grow production and reserves through the drillbit. We are currently utilizing 138 operated drilling rigs and 77 non-operated drilling rigs to conduct the most active drilling program in the U.S. We are active in most of the unconventional plays in the U.S. east of the Rockies, where we drill more horizontal wells than any other company in the industry. For the past ten years, we have been actively investing in leasehold, 3-D seismic information and human capital to take advantage of the favorable drilling economics that exist today. We are one of the few large-cap independent oil and natural gas companies that have been able to consistently increase production, which we have successfully achieved for the past 18 consecutive years and 26 consecutive quarters. We believe the key elements of the success and scale of our drilling programs have been our recognition earlier than most of our competitors that (i) oil and natural gas prices were likely to move structurally higher for an extended period, (ii) new horizontal drilling and completion techniques would enable development of previously uneconomic natural gas reservoirs and (iii) various shale formations could be recognized and developed as potentially prolific natural gas reservoirs rather than just as sources of natural gas. In response to our early recognition of these trends, we have proactively hired thousands of new employees and have built the nation s largest onshore leasehold and 3-D seismic inventories, the building blocks of a successful large-scale drilling program and the foundation of value creation in our industry.

Control Substantial Land and Drilling Location Inventories. After we identified the trends discussed above, we initiated a plan to build and maintain the largest inventory of onshore drilling opportunities in the U.S. Anticipating an increase in commodity prices and recognizing that better horizontal drilling and completion technologies when applied to various new shale plays would likely create a unique opportunity to capture decades worth of drilling opportunities, we embarked on a very aggressive lease acquisition program which we have referred to as the land grab . We believed that the winner of the land grab would enjoy a distinctive competitive advantage for decades to come as other companies would be locked out of the best new shale plays in the U.S. We believe that we have executed our land grab strategy with particular distinction. We now own approximately 13 million net acres of leasehold in the U.S. and have identified more than 36,300 drilling opportunities on this leasehold. We believe this deep backlog of drilling, more than ten years worth at current drilling levels, provides unusual confidence and transparency into our future growth capabilities.

Develop Proprietary Technological Advantages. In addition to our industry-leading leasehold position, we have developed a number of proprietary technological advantages. First, we have acquired what we believe is the nation s largest inventory of three-dimensional (3-D) seismic information. Possessing this 3-D inventory enables us to image deep reservoirs of natural gas that might otherwise remain undiscovered and to drill our horizontal wells more accurately inside the targeted shale formation. In addition, we have developed an industry-leading information-gathering program that gives us proprietary insights into new plays and competitor activity. As a result of our initiatives, we now produce approximately 4% of the nation s natural gas, drill 8% of its wells and participate in almost an equal number of wells drilled by others. Consequently, we believe that we receive drilling information on 20-25% of the wells drilled in areas in which we are focused. By gathering this information on a real-time basis, then quickly assimilating and analyzing the information, we are able to react

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quickly to opportunities that are created through our drilling program and those of our competitors. Finally, we have recently constructed a unique state-of-the-art Reservoir Technology Center (RTC) in Oklahoma City. The RTC enables us to more quickly, accurately and confidentially analyze core data from shale wells and then design fracture stimulation procedures that are designed to work most productively in the shale formations that have been analyzed. We believe the RTC provides a very substantial competitive advantage in developing new shale plays and improving existing shale plays.

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 superior geoscientific and engineering information, 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 ten years ago 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 approximately 98% over the past 18 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.

Focus on Low Costs. By minimizing lease operating costs and general and administrative expenses through focused activities and increased scale, we have been able to deliver attractive financial returns through all phases of the commodity price cycle. We believe our low cost structure is the result of management s effective cost-control programs, a high-quality asset base, extensive and competitive services and 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, 2007, we operated approximately 22,400 of our 38,500 wells, which delivered approximately 85% of our daily production volume. This large percentage of operated properties provides us with a high degree of operating flexibility and cost control.

Mitigate Commodity Price Risk. We have used and intend to continue using hedging programs to seek to mitigate the risks inherent in developing 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. As of February 21, 2008, we have oil hedges in place covering 94% and 97% of our expected oil production in 2008 and 2009, respectively, and 87% and 54% of our expected natural gas production in 2008 and 2009, respectively, thereby providing price certainty for a substantial portion of our future cash flow.

Maintain an Entrepreneurial Culture. Chesapeake was formed 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 largest independent producer of natural gas in the U.S. with 6,400 employees currently and an enterprise value of approximately $36 billion. The company takes pride in its innovative and aggressive implementation of its business strategy and strives to be as entrepreneurial today as it has been in its past. We have maintained an unusually flat organizational structure as we have grown to help ensure that important information travels rapidly through the company and decisions are made and implemented quickly. Our chief executive officer and co-founder, Aubrey K. McClendon, has been in the oil and natural gas industry for 27 years and beneficially owns, as of February 29, 2008, approximately 28.4 million shares of our common stock.

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Improve our Balance Sheet. We have made significant progress in improving our balance sheet over the past nine years. From December 31, 1998 through December 31, 2007, we increased our stockholders equity by $12.4 billion through a combination of earnings and common and preferred equity issuances. As of December 31, 2007, our debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders equity) was 47%, compared to 137% as of December 31, 1998.

Outlook

We believe that demand for natural gas will continue to increase in the U.S. and around the world as a result of its favorable environmental characteristics and relative abundance, especially when compared to oil, which is in increasingly short supply, and to coal, which has many unfavorable environmental characteristics. Chesapeake s strategy for 2008 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 other operating areas. We project that our 2008 production will be between 851 bcfe and 861 bcfe, a 19% to 21% increase over 2007 production. We have budgeted $5.9 billion to $6.5 billion for drilling, acreage acquisition, seismic and related capitalized internal costs, which is expected to be funded with operating cash flow based on our current assumptions, our 2008-2009 financial plan 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.

Operating Areas

Chesapeake focuses its natural gas exploration, development and acquisition efforts in the six operating areas described below.

Mid-Continent. Chesapeake s Mid-Continent proved reserves of 5.122 tcfe represented 47% of our total proved reserves as of December 31, 2007, and this area produced 374 bcfe, or 52%, of our 2007 production. During 2007, we invested approximately $2.1 billion to drill 2,126 (785 net) wells in the Mid-Continent. For 2008, we anticipate spending approximately 38% of our total budget for exploration and development activities in the Mid-Continent region.

Barnett Shale. Chesapeake s Barnett Shale proved reserves represented 2.063 tcfe, or 19%, of our total proved reserves as of December 31, 2007. During 2007, the Barnett Shale assets produced 93 bcfe, or 13%, of our total production. During 2007, we invested approximately $1.3 billion to drill 512 (410 net) wells in the Barnett Shale. For 2008, we anticipate spending approximately 35% of our total budget for exploration and development activities in the Barnett Shale.

Appalachian Basin. Chesapeake s Appalachian Basin proved reserves represented 1.404 tcfe, or 13%, of our total proved reserves as of December 31, 2007. During 2007, the Appalachian assets produced 48 bcfe, or 7%, of our total production. During 2007, we invested approximately $344 million to drill 431 (374 net) wells in the Appalachian Basin. For 2008, we anticipate spending approximately 5% of our total budget for exploration and development activities in the Appalachian Basin.

Permian and Delaware Basins. Chesapeake s Permian and Delaware Basin proved reserves represented 990 bcfe, or 9%, of our total proved reserves as of December 31, 2007. During 2007, the Permian assets produced 65 bcfe, or 9%, of our total production. During 2007, we invested approximately $813 million to drill 253 (107 net) wells in the Permian and Delaware Basins. For 2008, we anticipate spending approximately 12% 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 695 bcfe, or 6%, of our total proved reserves as of December 31, 2007. During 2007, the Ark-La-Tex assets produced 56 bcfe, or 8%, of our total production. During 2007, we invested approximately $556 million to drill 259 (176 net) wells in the Ark-La-Tex

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region. For 2008, we anticipate spending approximately 4% 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 605 bcfe, or 6%, of our total proved reserves as of December 31, 2007. During 2007, the South Texas and Texas Gulf Coast assets produced 78 bcfe, or 11%, of our total production. For 2007, we invested approximately $315 million to drill 90 (67 net) wells in the South Texas and Texas Gulf Coast regions. For 2008, we anticipate spending approximately 6% 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.

	2007				2006				2005			
	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent
Development:												
Productive	3,439	98%	1,792	99%	2,844	98%	1,364	99%	1,736	97%	735	97%
Non-productive	53	2	10	1	47	2	13	1	51	3	21	3
Total	3,492	100%	1,802	100%	2,891	100%	1,377	100%	1,787	100%	756	100%
Exploratory:												
Productive	177	99%	116	99%	128	98%	71	99%	177	98%	57	95%
Non-productive	2	1	1	1	3	2	1	1	4	2	3	5
Total	179	100%	117	100%	131	100%	72	100%	181	100%	60	100%

The following table shows the wells we drilled by area:

	2007		2006		2005	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Mid-Continent	2,126	785	1,884	621	1,442	498
Barnett Shale	512	410	244	187		
Appalachian Basin	431	374	319	272	15	11
Permian and Delaware Basins	253	107	189	92	139	56
Ark-La-Tex	259	176	248	175	257	171
South Texas and Texas Gulf Coast	90	67	138	102	115	80
Total	3,671	1,919	3,022	1,449	1,968	816

At December 31, 2007, we had 289 (132 net) wells in process.

Well Data

At December 31, 2007, we had interests in approximately 38,500 (21,404 net) producing wells, including properties in which we held an overriding royalty interest, of which 6,900 (3,832 net) were classified as primarily oil producing wells and 31,600 (17,572 net) were classified as primarily natural gas producing wells. Chesapeake operates approximately 22,400 of its 38,500 producing wells. During 2007, we drilled 1,992 (1,695 net) wells and participated in another 1,679 (224 net) wells operated by other companies. We operate approximately 85% of our current daily production volumes.

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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,		
	2007	**2006**	**2005**
Net Production:			
Oil (mbbls)	9,882	8,654	7,698
Natural gas (mmcf)	654,969	526,459	422,389
Natural gas equivalent (mmcfe)	714,261	578,383	468,577
Oil and Natural Gas Sales ($ in millions):			
Oil sales	$ 678	$ 527	$ 402
Oil derivatives realized gains (losses)	(11)	(15)	(34)
Oil derivatives unrealized gains (losses)	(235)	28	4
Total oil sales	432	540	372
Natural gas sales	4,117	3,343	3,231
Natural gas derivatives realized gains (losses)	1,214	1,269	(367)
Natural gas derivatives unrealized gains (losses)	(139)	467	37
Total natural gas sales	5,192	5,079	2,901
Total oil and natural gas sales	$ 5,624	$ 5,619	$ 3,273
Average Sales Price (excluding gains (losses) on derivatives):			
Oil ($ per bbl)	$ 68.64	$ 60.86	$ 52.20
Natural gas ($ per mcf)	$ 6.29	$ 6.35	$ 7.65
Natural gas equivalent ($ per mcfe)	$ 6.71	$ 6.69	$ 7.75
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Oil ($ per bbl)	$ 67.50	$ 59.14	$ 47.77
Natural gas ($ per mcf)	$ 8.14	$ 8.76	$ 6.78
Natural gas equivalent ($ per mcfe)	$ 8.40	$ 8.86	$ 6.90
Other Operating Income ($ per mcfe):			
Oil and natural gas marketing	$ 0.10	$ 0.09	$ 0.07
Service operations	$ 0.06	$ 0.11	$
Expenses ($ per mcfe):			
Production expenses	$ 0.90	$ 0.85	$ 0.68
Production taxes	$ 0.30	$ 0.31	$ 0.44
General and administrative expenses	$ 0.34	$ 0.24	$ 0.14
Oil and natural gas depreciation, depletion and amortization	$ 2.57	$ 2.35	$ 1.91
Depreciation and amortization of other assets	$ 0.22	$ 0.18	$ 0.11
Interest expense (a)	$ 0.51	$ 0.52	$ 0.47

(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.

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Oil and Natural Gas Reserves

The tables below set forth information as of December 31, 2007 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, 2007		
	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)
Proved developed	88,834	6,408,622	6,941,626
Proved undeveloped	34,720	3,728,677	3,936,997
Total proved	123,554	10,137,299	10,878,623

	Proved Developed	Proved Undeveloped ($ in millions)	Total Proved
Estimated future net revenue (a)	$ 33,523	$ 12,798	$ 46,321
Present value of estimated future net revenue (a)	$ 16,621	$ 3,952	$ 20,573
Standardized measure (a)(b)			$ 14,962

	Oil (mbbl)	Gas (mmcf)	Gas Equivalent (mmcfe)	Percent of Proved Reserves	Present Value ($ in millions)
Mid-Continent	66,256	4,723,987	5,121,522	47%	$ 11,050
Barnett Shale	102	2,062,476	2,063,091	19	2,969
Appalachian Basin	1,491	1,394,635	1,403,579	13	1,260
Permian and Delaware Basins	47,146	707,426	990,303	9	2,548
Ark-La-Tex	4,319	669,384	695,300	6	1,155
South Texas and Texas Gulf Coast	4,240	579,391	604,828	6	1,591
Total	123,554	10,137,299	10,878,623	100%	$ 20,573(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, 2007. The prices used in our external and internal reserve reports yield weighted average wellhead prices of $90.58 per barrel of oil and $6.19 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, 2007. 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 ($5.6 billion as of December 31, 2007).

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.

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As of December 31, 2007, our reserve estimates included 3.937 tcfe of reserves classified as proved undeveloped (PUD). Of this amount, approximately 32%, 23% and 25% (by volume) were initially classified as PUDs in 2007, 2006 and 2005, respectively, and the remaining 20% were initially classified as PUDs prior to 2005. Of our proved developed reserves, 904 bcfe are non-producing, which are primarily behind pipe zones in producing wells.

The future net revenue attributable to our estimated proved undeveloped reserves of $12.8 billion at December 31, 2007, and the $4.0 billion present value thereof, have been calculated assuming that we will expend approximately $7.3 billion to develop these reserves. We have projected to incur $2.6 billion in 2008, $2.0 billion in 2009, $1.0 billion in 2010 and $1.7 billion in 2011 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. 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. 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 79% of our proved reserves (by volume) at year-end 2007. 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. The estimates prepared by the independent firms covered approximately 23,000 properties, or 45% of the 50,700 properties included in the 2007 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 21% 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. The portion of our estimated proved reserves evaluated by each of our third-party engineering firms as of December 31, 2007 is presented below.

	% Evaluated (by Volume)	Principal Properties Evaluated
Netherland, Sewell & Associates, Inc.	34%	Permian and Delaware Basins, Barnett Shale, portions of Ark-La-Tex, portions of Mid-Continent
Data and Consulting Services, Division of Schlumberger Technology Corporation	12%	Appalachian Basin
Lee Keeling and Associates, Inc.	11%	Portions of Mid-Continent, portions of South Texas/Texas Gulf Coast
Ryder Scott Company, L.P.	11%	Portions of Mid-Continent, portions of South Texas/Texas Gulf Coast
LaRoche Petroleum Consultants, Ltd.	11%	Portions of Mid-Continent, portions of Ark-La-Tex

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.

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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, 2007. 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, 2007 present value of estimated future net revenue of our proved reserves of approximately $390 million and $56 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, 2007, 2006 and 2005, 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.

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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:

	2007	December 31, 2006 ($ in millions)	2005
Development and exploration costs:			
Development drilling (a)	$ 4,402	$ 2,772	$ 1,567
Exploratory drilling	653	349	253
Geological and geophysical costs (b)	343	154	71
Asset retirement obligation and other	29	23	52
Total	5,427	3,298	1,943
Acquisition costs:			
Proved properties	671	1,175	3,554
Unproved properties (c)	2,465	3,473	1,667
Deferred income taxes	131	180	252
Total	3,267	4,828	5,473
Sales of oil and natural gas properties	(1,142)		(9)
Total	$ 7,552	$ 8,126	$ 7,407

(a) Includes capitalized internal cost of $243 million, $147 million and $94 million, respectively.
(b) Includes capitalized internal cost of $19 million, $13 million and $8 million, respectively.
(c) Includes costs to acquire new leasehold, unproved properties and related capitalized interest.

Our development costs included $1.5 billion, $1.2 billion and $671 million in 2007, 2006 and 2005, respectively, related to properties carried as proved undeveloped locations in the prior year s reserve reports.

A summary of our exploration and development, acquisition and divestiture activities in 2007 by operating area is as follows:

	Gross Wells Drilled	Net Wells Drilled	Exploration and Development	Acquisition of Unproved Properties ($ in millions)	Acquisition of Proved Properties (a)	Sales of Properties	Total
Mid-Continent	2,126	785	$ 2,140	$ 1,038	$ 538	$	$ 3,716
Barnett Shale	512	410	1,259	681	6		1,946
Appalachian Basin	431	374	344	149	9	(1,142)	(640)
Permian and Delaware Basins	253	107	813	422	170		1,405
Ark-La-Tex	259	176	556	138	43		737
South Texas and Texas Gulf Coast	90	67	315	37	36		388
Total	3,671	1,919	$ 5,427	$ 2,465	$ 802	$ (1,142)	$ 7,552

(a) Includes $131 million of deferred tax adjustments.

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Acreage

The following table sets forth as of December 31, 2007 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 Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Mid-Continent	4,266,308	2,091,034	5,270,933	2,755,286	9,537,241	4,846,320
Barnett Shale	88,992	75,040	231,906	166,384	320,898	241,424
Appalachian Basin	522,591	522,591	4,474,155	4,027,473	4,996,746	4,550,064
Permian and Delaware Basins	361,339	202,990	2,968,378	1,819,598	3,329,717	2,022,588
Ark-La-Tex	266,538	162,268	1,302,267	729,427	1,568,805	891,695
South Texas and Texas Gulf Coast	341,591	204,137	234,036	167,935	575,627	372,072
Total	5,847,359	3,258,060	14,481,675	9,666,103	20,329,034	12,924,163

Marketing

Chesapeake Energy Marketing, Inc., a wholly owned subsidiary of Chesapeake Energy Corporation, provides marketing services including commodity price structuring, contract administration and nomination services for Chesapeake and its partners. We attempt to enhance the value of our natural gas production by aggregating natural gas to be sold to natural gas marketers and pipelines. This aggregation allows us to attract larger, creditworthy customers that in turn assist in maximizing the prices received for our production.

Our 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 2008, approximately 80% of our natural gas production was sold under short-term contracts at market-sensitive prices.

During 2007, sales to Eagle Energy Partners I, L.P. (Eagle) of $1.1 billion accounted for 15% of our total revenues (excluding gains (losses) on derivatives). In 2007, we sold our 33% limited partnership interest in Eagle Energy Partners I, L.P., which we first acquired in 2003, for proceeds of $124 million and a gain of $83 million. 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 2007.

Chesapeake Energy Marketing, Inc. 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.

Natural Gas Gathering

Chesapeake invests in gathering and processing facilities to complement our oil and natural gas operations in regions where we have significant production. By doing so, we are better able to manage the value received for and the costs of, gathering, treating and processing natural gas through our ownership and operation of these facilities. We own and operate gathering systems in 13 states throughout the Mid-Continent and Appalachian

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regions. These systems are designed primarily to gather company production for delivery into major intrastate or interstate pipelines and are comprised of approximately 8,900 miles of gathering lines, treating facilities and processing facilities which provide service to approximately 11,000 wells.

We are currently in the process of forming a private partnership to own a non-operating interest in our midstream natural gas assets outside of Appalachia, which consist primarily of natural gas gathering systems and processing assets. We anticipate raising $1 billion for a minority interest in the partnership and closing the transaction in the first half of 2008.

Drilling

Securing available rigs is an integral part of the exploration process and therefore owning our own drilling company is a strategic advantage for Chesapeake. In 2001, Chesapeake formed its 100% owned drilling rig subsidiary, Nomac Drilling Corporation, with an investment of $26 million to build and refurbish five drilling rigs. As of December 31, 2007, Chesapeake had invested approximately $675 million to build or acquire 80 drilling rigs and to initiate the construction of one additional rig. During 2006 and 2007, we sold 78 rigs for $613 million and subsequently leased back the rigs through 2017. The drilling rigs have depth ratings between 3,000 and 25,000 feet and range in drilling horsepower from 350 to 2,000. These drilling rigs are currently operating in Oklahoma, Texas, Arkansas, Louisiana and Appalachia. The company s drilling rig fleet should reach 84 rigs by mid-year 2008, which would rank Chesapeake as the fifth largest drilling rig contractor in the U.S.

Trucking

In 2006, Chesapeake expanded its service operations by acquiring two privately-owned oilfield trucking service companies. We now own one of the largest oilfield and heavy haul transportation companies in the industry. Our trucking business is utilized primarily to transport drilling rigs for both Chesapeake and third parties. Through this ownership we are better able to manage the movement of our rigs. As of December 31, 2007, our fleet included 178 trucks and 13 cranes which mainly service the Mid-Continent, Barnett Shale and Appalachian regions.

Compression

During the past few years Chesapeake has expanded its compression business. Our wholly-owned subsidiary, MidCon Compression, L.L.C., operates wellhead and system compressors to facilitate the transportation of our natural gas production. In a series of transactions in 2007, MidCon sold a significant portion of its compressor fleet, consisting of 1,199 compressors, for $188 million and entered into a master lease agreement. These transactions were recorded as sales and operating leasebacks. Over the next 18 months, 365 new compressors are on order for $175 million, and we intend to simultaneously enter into sale/leaseback transactions with a financial counterparty as the compressors are delivered.

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 regulated at the federal, state and local levels, and some of the laws, rules and regulations that govern our operations carry substantial penalties for noncompliance. These regulatory burdens increase our cost of doing business and, consequently, affect our profitability.

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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. 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. Very few of our oil and natural gas leases are located on federal lands. 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 generated 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 that 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, 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 and 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 material adverse effect upon our capital expenditures, earnings or competitive position.

Environmental, Health and Safety Regulation. The business operations of the company and its ownership and operation of real property are subject to various federal, state and local environmental, health and safety laws and regulations pertaining to the discharge of materials into the environment, the generation, storage, transportation, handling and disposal of materials (including solid and hazardous wastes), the safety of employees, or otherwise relating to pollution, preservation, remediation or protection of human health and safety, natural resources, wildlife or the environment. 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 frameworks relate to the handling of drilling and production materials, the disposal of drilling and production wastes, and the protection of water and air. In addition, our operations may require us to obtain permits for, among other things, air emissions,

the construction and operation of underground injection wells to dispose of produced saltwater and other non-hazardous oilfield wastes, and

the construction and operation of surface pits to contain drilling muds and other non-hazardous fluids associated with drilling operations.

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Under federal, state and local 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 at contaminated areas, or to perform remedial well plugging operations or response actions to reduce the risk of future contamination. Federal and state laws, including the Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, impose joint and several liability, without regard to fault or legality of the original conduct, on classes of persons who are considered responsible for response actions to address the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and persons that disposed of or arranged for the disposal of hazardous substances at the site. 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 actions. 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 and maintain 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, health and safety regulations and requirements. These are necessary business costs in the oil and natural gas industry. Although we are not fully insured against all environmental, health and safety 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, health and safety 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 material compliance with existing environmental, health and safety 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 business, financial position and results of operations.

Income Taxes

Chesapeake recorded income tax expense of $890 million in 2007 compared to income tax expense of $1.252 billion in 2006 and $545 million in 2005. Of the $362 million decrease in 2007, $347 million was the result of the decrease in net income before taxes and $15 million was the result of a decrease in the effective tax rate. Our effective income tax rate was 38% in 2007 compared to 38.5% in 2006 and 36.5% in 2005. Our effective tax rate fluctuates as a result of the impact of state income taxes and permanent differences between our accounting for certain revenue or expense items and their corresponding treatment for income tax purposes. We expect our effective income tax rate to be 38.5% in 2008.

At December 31, 2007, Chesapeake had federal income tax net operating loss (NOL) carryforwards of approximately $238 million and approximately $29 million of percentage depletion carryforwards. We also had approximately $5 million of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income. The NOL carryforwards expire from 2019 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.

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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, 2007 and any related limitations:

	Net Operating Losses		
	Total	Limited	Annual Limitation
		($ in millions)	
Net operating loss	$ 238	$ 27	$ 10
AMT net operating loss	$ 5	$ 5	$ 1

As of December 31, 2007, 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.

In June 2006, the Financial Accounting Standards Board (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 became effective for fiscal years beginning after December 15, 2006.

Chesapeake adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, Chesapeake recognized a $7 million liability for accrued interest associated with uncertain tax positions which was accounted for as a reduction in the January 1, 2007 balance of retained earnings, net of tax. At the date of adoption, we had approximately $142 million of unrecognized tax benefits related to alternative minimum tax (AMT) associated with uncertain tax positions. As of December 31, 2007, the amount of unrecognized tax benefits related to AMT associated with uncertain tax positions was $133 million. If these unrecognized tax benefits are disallowed and we are ultimately required to pay additional AMT liabilities, any payments can be utilized as credits against future regular tax liabilities. The uncertain tax positions identified would not have a material effect on the effective tax rate. At December 31, 2007, we had a liability of $5 million for interest related to these same uncertain tax positions. Chesapeake recognizes interest related to uncertain tax positions in interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses.

Chesapeake files income tax returns in the U.S. federal jurisdiction and various state and local jurisdictions. With few exceptions, Chesapeake is no longer subject to U.S. federal, state and local income tax examinations by tax authorities for years prior to 2004. The Internal Revenue Service (IRS) completed an examination of Chesapeake s U.S. income tax returns for 2003 and 2004 in September 2007. This examination resulted in

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additional AMT liabilities of $9 million. These AMT liabilities can be utilized as credits against future regular tax liabilities. The adjustments in the examination did not result in a material change to our financial position, results of operations or cash flows.

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 control of well 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 $300 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. 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 we are in the process of constructing additional corporate facilities in Oklahoma City and Charleston, West Virginia. We also own or lease various field offices in the following locations:

- Arkansas: Searcy and Little Rock
- 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: Horseheads

Oklahoma: Arkoma, Billings, El Reno, Elk City, Enid, Forgan, Hartshorne, Hinton, Kingfisher, Lindsay, Mayfield, Oklahoma City, Waynoka, Weatherford, Wilburton and Woodward

Pennsylvania: Mt. Morris

Tennessee: Egan

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Texas: Alvarado, Borger, Bryan, Cleburne, College Station, Dumas, Fort Worth, Garrison, Marshall, Midland, Ozona, Pecos, Tyler, Victoria and Zapata

West Virginia: Branchland, Buckhannon, Chapmanville, Cedar Grove, Clendenin, Hamlin, Kermit, Shrewsbury, Tad and Teays Valley

Employees

Chesapeake had approximately 6,200 employees as of December 31, 2007, which includes 2,271 employed by our service operations companies. As a result of the CNR acquisition, we assumed a collective bargaining agreement with the United Steel Workers of America (USWA) which expired effective December 1, 2006, covering approximately 135 of our field employees in West Virginia and Kentucky. We continued to operate under the terms of the collective bargaining agreement while negotiating with the USWA. Contract negotiations began in October 2006 and have been mediated by the Federal Mediation and Conciliation Service. On May 4, 2007, we presented the USWA leadership our last, best and final offer . On December 7, 2007, the USWA membership voted to reject our offer and, effective February 1, 2008 we implemented the terms of our offer with certain minor clarifications. There have been no strikes, work stoppages or slowdowns 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.

Bbtu. One billion British thermal units.

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.

Conventional Reserves. Oil and natural gas occurring as discrete accumulations in structural and stratigraphic traps.

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.

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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.

Infill Drilling. Drilling wells between established producing wells on a lease; a drilling program to reduce the spacing between wells in order to increase production and/or recovery of in-place hydrocarbons from the lease.

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.

Mmcfe. 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.

Play. A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and gas reserves.

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%.

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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.

Seismic. An exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of subsurface rock formation (3-D seismic provides three-dimensional pictures).

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Shale. Fine-grained sedimentary rock composed mostly of consolidated clay or mud. Shale is the most frequently occurring sedimentary rock.

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.

Unconventional Reserves. Oil and natural gas occurring in regionally pervasive accumulations with low matrix permeability and close association with source rocks.

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.

Unproved Properties. Properties with no proved reserves.

VPP. A volumetric production payment represents an obligation of the purchaser of a property to deliver a specific volume of production, free and clear of all costs, to the seller of the property.

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;

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- 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, 2007 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, 2007, we had long-term indebtedness of approximately $10.950 billion, with $1.950 billion of outstanding borrowings drawn under our revolving bank credit facility. Our long-term indebtedness represented 47% of our total book capitalization at December 31, 2007. As of February 26, 2008, we had approximately $2.899 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; and
- 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.

We may incur additional debt, including secured indebtedness, or issue additional series of preferred stock in order to develop our properties and make future acquisitions. 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.

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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 development, exploitation, exploration, acquisition 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 36% of our total estimated proved reserves (by volume) at December 31, 2007 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 28% from 2008 to 2009. 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.

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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, 2007, approximately 36% 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 $2.6 billion in 2008. 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, 2007 present value is based on weighted average oil and natural gas wellhead prices of $90.58 per barrel of oil and $6.19 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. 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

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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.

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 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, 2007 was a liability of approximately $369 million. In addition, our commodity price risk management transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

our production is less than expected;

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- 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 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 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 $3.5 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 additional indebtedness under both 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 failures, 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 or 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 other hazardous substances at, 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

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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, studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases, may be contributing to warming of the Earth s atmosphere. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas, are examples of greenhouse gases. The U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases. In addition, at least nine states in the Northeast and five states in the West including New Mexico have developed initiatives to regulate emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. The U.S. Environmental Protection Agency is separately considering whether it will regulate greenhouse gases as air pollutants under the existing federal Clean Air Act. Passage of climate control legislation or other regulatory initiatives by Congress or various states in the U.S. or the adoption of regulations by the EPA or analogous state agencies that regulate or restrict emissions of greenhouse gases including methane or carbon dioxide in areas in which we conduct business could have an adverse effect on our operations and demand for our products.

A portion of our oil and gas production may be subject to interruptions that could temporarily adversely affect our cash flow.

A portion of our regional oil and gas production may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or intentionally as a result of market conditions. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow.

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 fraudulent conduct by the defendants with respect to the sales prices used to calculate royalty payments and with respect to the failure of CNR to disclose post-production deductions. On June 28, 2007, the Circuit Court sustained the jury verdict for punitive damages, and on September 27, 2007, it denied all post-trial motions, including defendants motion for judgment as a matter of law, or in the alternative, for a new trial. On December 5, 2007, the Circuit Court entered an order granting defendants motion to stay the judgment pending appeal conditioned upon filing an irrevocable letter of credit in the amount of $50 million. The irrevocable letter of credit was filed January 4, 2008. On January 24, 2008, the defendants filed a Petition for Appeal in the West Virginia Supreme Court of Appeals.

Chesapeake and NiSource maintain CNR acted in good faith and paid royalties in accordance with lease terms and West Virginia law. 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 adverse effect on the company.

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

Not applicable.

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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, 2007:		
Fourth Quarter	$ 41.19	$ 34.90
Third Quarter	37.55	31.38
Second Quarter	37.75	30.88
First Quarter	31.83	27.27
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

At February 26, 2008, there were 1,651 holders of record of our common stock and approximately 260,000 beneficial owners.

Dividends

The following table sets forth the amount of dividends per share declared on Chesapeake common stock during 2007 and 2006:

	2007	**2006**
Fourth Quarter	$ 0.0675	$ 0.06
Third Quarter	0.0675	0.06
Second Quarter	0.0675	0.06
First Quarter	0.06	0.05

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, 2007, our coverage ratio for purposes of the debt incurrence test under the relevant indentures was 7.46 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 $1.9 billion.

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The following table presents information about repurchases of our common stock during the three months ended December 31, 2007:

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, 2007 through October 31, 2007	5,491	$ 39.236		
November 1, 2007 through November 30, 2007	5,667	$ 37.875		
December 1, 2007 through December 31, 2007	6,726	$ 39.210		
Total	17,884	$ 38.795		

(a) Includes the deemed surrender to the company of 1,417 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 16,467 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.

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ITEM 6. ***Selected Financial Data***

The following table sets forth selected consolidated financial data of Chesapeake for the years ended December 31, 2007, 2006, 2005, 2004 and 2003. 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,				
	2007	2006	2005	2004	2003
	($ in millions, except per share data)				
Statement of Operations Data:					
Revenues:					
Oil and natural gas sales	$ 5,624	$ 5,619	$ 3,273	$ 1,936	$ 1,297
Oil and natural gas marketing sales	2,040	1,577	1,392	773	420
Service operations revenue	136	130			
Total revenues	7,800	7,326	4,665	2,709	1,717
Operating costs:					
Production expenses	640	490	317	205	138
Production taxes	216	176	208	104	78
General and administrative expenses	243	139	64	37	24
Oil and natural gas marketing expenses	1,969	1,522	1,358	755	410
Service operations expense	94	68			
Oil and natural gas depreciation, depletion and amortization	1,835	1,359	894	582	369
Depreciation and amortization of other assets	154	104	51	29	17
Employee retirement expense		55			
Provision for legal settlements				5	6
Total operating costs	5,151				