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:

	December 31, 2007	2006	2005
	($ in millions)		
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	Acquisition of Proved Properties (a)	Sales of Properties	Total
				($ in millions)			
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).

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

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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	3,913	2,892	1,717	1,042
Income from operations	2,649	3,413	1,773	992	675
Other income (expense):					
Interest and other income	15	26	10	5	1
Interest expense	(406)	(301)	(220)	(167)	(154)
Gain on sale of investment	83	117			
Loss on repurchases or exchanges of Chesapeake senior notes			(70)	(25)	(21)
Total other income (expense)	(308)	(158)	(280)	(187)	(174)
Income before income taxes and cumulative effect of accounting change	2,341	3,255	1,493	805	501
Income tax expense (benefit):					
Current	29	5			5
Deferred	861	1,247	545	290	185
Total income tax expense	890	1,252	545	290	190
Net income before cumulative effect of accounting change, net of tax	1,451	2,003	948	515	311
Cumulative effect of accounting change, net of income taxes of $1 million					2
Net Income	1,451	2,003	948	515	313
Preferred stock dividends	(94)	(89)	(42)	(40)	(22)
Loss on conversion/exchange of preferred stock	(128)	(10)	(26)	(36)	

Net income available to common shareholders	$ 1,229	$ 1,904	$ 880	$ 439	$ 291
Earnings per common share basic:					
Income before cumulative effect of accounting change	$ 2.69	$ 4.78	$ 2.73	$ 1.73	$ 1.36
Cumulative effect of accounting change					0.02
	$ 2.69	$ 4.78	$ 2.73	$ 1.73	$ 1.38
Earnings per common share assuming dilution:					
Income before cumulative effect of accounting change	$ 2.62	$ 4.35	$ 2.51	$ 1.53	$ 1.20
Cumulative effect of accounting change					0.01
	$ 2.62	$ 4.35	$ 2.51	$ 1.53	$ 1.21
Cash dividends declared per common share	$ 0.2625	$ 0.23	$ 0.195	$ 0.17	$ 0.135

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	Years Ended December 31, 2007	2006	2005	2004	2003
	($ in millions, except per share data)				
Cash Flow Data:					
Cash provided by operating activities	$ 4,932	$ 4,843	$ 2,407	$ 1,432	$ 939
Cash used in investing activities	7,922	8,942	6,921	3,381	2,077
Cash provided by financing activities	2,988	4,042	4,567	1,915	931
Balance Sheet Data (at end of period):					
Total assets	$ 30,734	$ 24,417	$ 16,118	$ 8,245	$ 4,572
Long-term debt, net of current maturities	10,950	7,376	5,490	3,075	2,058
Stockholders equity	12,130	11,251	6,174	3,163	1,733

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

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

	Years Ended December 31, 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 (a) ($ in millions):			
Oil and natural gas marketing	$ 71	$ 55	$ 35
Service operations	$ 42	$ 62	$
Other Operating Income (a) ($ 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 (b)	$	0.51	$	0.52	$	0.47
Interest Expense ($ in millions):						
Interest expense	$	365	$	301	$	227
Interest rate derivatives realized (gains) losses		1		2		(5)
Interest rate derivatives unrealized (gains) losses		40		(2)		(2)
Total interest expense	$	406	$	301	$	220
Net Wells Drilled		1,919		1,449		816
Net Producing Wells as of the End of Period		21,404		19,079		16,985

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(a) Includes revenue and operating costs and excludes depreciation and amortization of other assets.
(b) Includes the effects of realized gains (losses) from interest rate derivatives, but excludes the effects of unrealized gains (losses) and is net of amounts capitalized.

We manage our business as three separate operational segments: exploration and production; marketing; and service operations, which is comprised of our wholly owned drilling and trucking operations. We refer you to Note 8 of the notes to our consolidated financial statements appearing in Item 8 of this report, which summarizes by segment our net income and capital expenditures for 2007, 2006 and 2005 and our assets as of December 31, 2007, 2006 and 2005.

Executive Summary

We are the third largest 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 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 in various conventional plays in 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 Basins Woodford Shale in Oklahoma, the Delaware Basin Barnett and Woodford Shales in West Texas, and the Alabama Conasauga and Chattanooga Shales.

Oil and natural gas production for 2007 was 714.3 bcfe, an increase of 135.9 bcfe, or 23% over the 578.4 bcfe produced in 2006. We have increased our production for 18 consecutive years and 26 consecutive quarters. During these 26 quarters, Chesapeake s U.S. production has increased 467% for an average compound quarterly growth rate of 7% and an average compound annual growth rate of 30%.

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.

Chesapeake began 2007 with estimated proved reserves of 8.956 tcfe and ended the year with 10.879 tcfe, an increase of 1.923 tcfe, or 21%. During 2007, we replaced 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 and 94% of the total increase (including 1.248 tcfe of positive performance revisions and 97 bcfe of positive revisions resulting from oil and natural gas price increases between December 31, 2006 and December 31, 2007). Reserve replacement through the acquisition of proved reserves was 377 bcfe, or 53% of production and 14% of the total increase. During 2007, we divested 208 bcfe of proved

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reserves. Our annual decline rate on producing properties is projected to be 28% from 2008 to 2009, 18% from 2009 to 2010, 14% from 2010 to 2011, 12% from 2011 to 2012 and 10% from 2012 to 2013. Our percentage of proved undeveloped reserve additions to total proved reserve additions was approximately 29% in 2007, 38% in 2006 and 36% in 2005. Based on our current drilling schedule and budget, we expect that virtually all of the proved undeveloped reserves added in 2007 will begin producing within the next three to five years. Generally, proved developed reserves are producing at the time they are added or will begin producing within one year.

Since 2000, Chesapeake has invested $9.4 billion in new leasehold and 3-D seismic acquisitions and now owns what we believe are the largest combined inventories of onshore leasehold (13 million net acres) and 3-D seismic (19 million acres) in the U.S. On this leasehold, the company has approximately 36,300 net drillsites representing more than a 10-year inventory of drilling projects.

As of December 31, 2007, the company s debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders equity) was 47% compared to 40% as of December 31, 2006. The average maturity of our long-term debt is almost nine years with an average interest rate of approximately 5.8%.

Liquidity and Capital Resources

2008 2009 Financial Plan

In early September 2007, we announced an enhanced financial plan designed to monetize unrecognized balance sheet value and to fully fund our planned capital expenditures through 2009 without accessing public capital markets. Since then, we have successfully implemented multiple aspects of the plan and anticipate further progress during 2008 and 2009. We believe our planned transactions described below will allow us to monetize approximately $3 billion of assets by the end of 2009.

Sale/Leasebacks. During 2007, we entered into sale/leaseback transactions involving 54 drilling rigs for net proceeds of approximately $369 million. We now operate a total of 78 rigs under sale/leaseback arrangements and anticipate similar transactions on our remaining 3 rigs during 2008, thereby completing the sale/leaseback of our entire fleet of 81 drilling rigs. Also during 2007, we completed a sale/leaseback facility for our natural gas compression assets. We received approximately $188 million for the sale/leaseback of our existing natural gas compression assets, and we will finance up to $175 million of future natural gas compression assets under the same facility.

Producing Property Sales. In December 2007, we monetized a portion of our proved reserves and production in certain Chesapeake-operated producing assets in Kentucky and West Virginia. In this transaction, we sold a volumetric production payment (VPP) to affiliates of UBS AG and DB Energy Trading LLC (a subsidiary of Deutsche Bank AG) for proceeds of approximately $1.1 billion. The VPP entitles the purchaser to receive scheduled quantities of natural gas from Chesapeake s interests in over 4,000 producing wells, free of all production costs and production taxes, over a 15-year period. The transaction included approximately 208 bcfe of proved reserves and 55 mmcfe per day of net production, or approximately 2% of our proved reserves and net production as of December 31, 2007. We have retained drilling rights on the properties below currently producing intervals and outside of existing producing wellbores. In addition, we plan to pursue monetizations of similarly mature properties in 2008 and 2009 for estimated proceeds of approximately $2.0 billion.

In the first quarter of 2008, we sold non-core oil and natural gas assets in the Rocky Mountains and in the Arkoma Basin Woodford Shale play for proceeds of approximately $250 million.

Midstream Partnership. 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 treating assets. We anticipate raising $1 billion in the first half of 2008 by selling a minority interest in the partnership.

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Sources and Uses of Funds

Cash flow from operations is our primary source of liquidity to meet operating expenses and fund capital expenditures (other than for acquisitions outside our budgeted leasehold and property acquisitions). Cash provided by operating activities was $4.932 billion in 2007, compared to $4.843 billion in 2006 and $2.407 billion in 2005. The $89 million increase from 2006 to 2007 was primarily due to higher volumes of oil and natural gas production. The $2.436 billion increase from 2005 to 2006 was primarily due to higher realized prices and higher volumes of oil and natural gas production. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding non-cash items, such as depreciation, depletion and amortization, deferred income taxes and unrealized gains and (losses) on derivatives. Net income decreased to $1.451 billion in 2007 from $2.003 billion in 2006 compared to $948 million in 2005 and is discussed below under *Results of Operations*.

Changes in market prices for oil and natural gas directly impact the level of our cash flow from operations. While a decline in oil or natural gas prices would affect the amount of cash flow that would be generated from operations, we currently (as of February 21, 2008) have oil hedges in place covering 94% of our expected oil production in 2008 and 87% of our expected natural gas production in 2008, thereby providing price certainty for a substantial portion of our future cash flow. Our oil and natural gas hedges as of December 31, 2007 are detailed in Item 7A of Part II of this report. We have arrangements with our hedging counterparties that allow us to minimize the potential liquidity impact of significant mark-to-market fluctuations in the value of our oil and natural gas hedges by making collateral allocations from our bank credit facility or directly pledging oil and natural gas properties, rather than posting cash or letters of credit with the counterparties. Depending on changes in oil and natural gas futures markets and management s view of underlying oil and natural gas supply and demand trends, we may increase or decrease our current hedging positions.

Our bank credit facility is another source of liquidity. On November 2, 2007, we amended and restated our syndicated revolving bank credit facility to increase the borrowing base to $3.5 billion (with commitments of $3.0 billion) and extended the maturity to November 2012. We subsequently increased the commitments under the credit facility to $3.5 billion. The amendment reflects the increased scale and scope of our operations and will help accommodate timing differences between cash flow from operations, asset monetizations and planned capital expenditures. At February 26, 2008, there was $596 million of borrowing capacity available under the revolving bank credit facility. We use the facility to fund daily operating activities and acquisitions as needed. We borrowed $7.9 billion and repaid $6.2 billion in 2007, we borrowed $8.4 billion and repaid $8.3 billion in 2006, and we borrowed $5.7 billion and repaid $5.7 billion in 2005 under the bank credit facility.

In 2007, we completed two public offerings of our 2.5% Contingent Convertible Senior Notes due 2037. In the first offering, in May 2007, we issued $1.150 billion of notes and in the second offering, in August 2007, we issued $500 million of notes. Net proceeds of approximately $1.124 billion and $483 million, respectively, were used to repay outstanding borrowings under our revolving bank credit facility. The following table reflects the proceeds from sales of securities we issued in 2007, 2006 and 2005, ($ in millions):

	2007		2006		2005	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
Unsecured senior notes	$	$	$ 1,799	$ 1,755	$ 2,300	$ 2,252
Contingent convertible unsecured senior notes	1,650	1,607			690	673
Convertible preferred stock			575	558	1,380	1,341
Common stock			1,800	1,759	1,025	986
Total	$ 1,650	$ 1,607	$ 4,174	$ 4,072	$ 5,395	$ 5,252

In December 2007, we sold a portion of our proved reserves and production in certain Chesapeake-operated producing assets in Kentucky and West Virginia. In this transaction, we sold a volumetric production payment (VPP) for proceeds of $1.1 billion, net of transaction costs.

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We believe our cash flow from operations, in combination with the proceeds expected from our planned producing property monetizations and other asset sales and the $1 billion increase in capacity under our bank credit facility will provide us with sufficient liquidity to execute our business strategy without accessing the public capital markets for the foreseeable future. We intend to use any cash in excess of our operating and capital expenditure needs to pay down indebtedness under our revolving bank credit facility.

Our primary use of funds is on capital expenditures for exploration, development and acquisition of oil and natural gas properties. We refer you to the table under *Investing Transactions* below, which sets forth the components of our oil and natural gas investing activities for 2007, 2006 and 2005. Our drilling, land and seismic capital expenditures are currently budgeted at $5.9 billion to $6.5 billion in 2008. We believe this level of exploration and development will enable us to increase our proved oil and natural gas reserves by more than 14% in 2008 and increase our total production by 19% to 21% in 2008 (inclusive of acquisitions completed or scheduled to close in 2008 through the filing date of this report but without regard to any additional acquisitions that may be completed in 2008).

We retain a significant degree of control over the timing of our capital expenditures which permits us to defer or accelerate certain capital expenditures if necessary to address any potential liquidity issues. In addition, higher drilling and field operating costs, drilling results that alter planned development schedules, acquisitions or other factors could cause us to revise our drilling program, which is largely discretionary.

We paid dividends on our common stock of $115 million, $87 million and $60 million in 2007, 2006 and 2005, respectively. The Board of Directors increased the quarterly dividend on common stock from $0.06 to $0.0675 per share beginning with the dividend paid in July 2007. We paid dividends on our preferred stock of $95 million, $88 million and $31 million in 2007, 2006 and 2005, respectively.

In 2007, holders of our 5.0% (Series 2005) cumulative convertible preferred stock and 6.25% mandatory convertible preferred stock exchanged 4,535,880 shares and 2,156,184 shares for 19,038,891 and 17,367,823 shares of common stock, respectively, in public exchange offers. The exchange resulted in a loss on conversion of $128 million.

We received $15 million, $73 million and $21 million from the exercise of employee and director stock options in 2007, 2006 and 2005, respectively. We paid $86 million and $4 million to purchase treasury stock in 2006 and 2005, respectively. Of these amounts, $11 million and $4 million were used to fund our matching contribution to our 401(k) plans in 2006 and 2005, respectively. The remaining $75 million in 2006 was used to purchase shares of common stock to be used upon the exercise of stock options under certain stock option plans. There were no treasury stock purchases made in 2007.

In 2007, 2006 and 2005, we paid $91 million, $87 million and $12 million, respectively, to settle a portion of the derivative liabilities assumed in our 2005 acquisition of Columbia Natural Resources, LLC.

On January 1, 2006, we adopted SFAS 123(R), which requires tax benefits resulting from stock-based compensation deductions in excess of amounts reported for financial reporting purposes to be reported as cash flows from financing activities. In 2007 and 2006, we reported a tax benefit from stock-based compensation of $20 million and $88 million, respectively.

Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists decreased by $98 million, increased by $70 million and increased by $61 million in 2007, 2006 and 2005, respectively. All disbursements are funded on the day they are presented to our bank using available cash on hand or draws on our revolving bank credit facility.

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Historically, we have used significant funds to redeem or purchase and retire outstanding senior notes issued by Chesapeake, although we had no such transactions in 2007 and 2006. The following table shows our redemption, purchases and exchanges of senior notes for 2005 ($ in millions):

	Senior Notes Activity				
For the Year Ended December 31, 2005:	**Retired**	**Premium**	**Other (a)**	**Issued**	**Cash Paid**
8.375% Senior Notes due 2008	$ 19	$ 1	$	$	$ 20
8.125% Senior Notes due 2011	245	17	1		263
9.0% Senior Notes due 2012	300	42	1		343
	$ 564	$ 60	$ 2	$	$ 626

(a) Includes adjustments to accrued interest and discount associated with notes retired and new notes issued, cash in lieu of fractional notes, transaction costs and fair value hedging adjustments.

Our accounts receivable are primarily from purchasers of oil and natural gas ($798 million at December 31, 2007) and exploration and production companies which own interests in properties we operate ($175 million at December 31, 2007). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from parties which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

Investing Transactions

Cash used in investing activities decreased to $7.922 billion in 2007, compared to $8.942 billion in 2006 and $6.921 billion in 2005. Over the past year, we have accelerated our drilling program and shifted our acquisition strategy from significant stock and asset acquisitions to targeted leasehold and property acquisitions needed for planned oil and natural gas development. Our investing activities during 2007 reflected our increasing focus on converting our resource inventory into production as well as elements of our new financial plan. The following table shows our cash used in (provided by) investing activities during 2007, 2006 and 2005 ($ in millions):

Oil and Natural Gas Investing Activities:	**2007**	**2006**	**2005**
Acquisitions of oil and natural gas companies and proved properties, net of cash acquired	$ 520	$ 1,104	$ 2,759
Acquisition of leasehold and unproved properties	2,187	3,301	1,591
Exploration and development of oil and natural gas properties	4,962	3,009	1,793
Geological and geophysical costs	343	154	71
Interest on leasehold and unproved properties	254	172	76
Proceeds from sale of volumetric production payment	(1,089)		
Deposits for acquisitions	15	21	35
Other oil and natural gas activities			(2)
Total oil and natural gas investing activities	7,192	7,761	6,323
Other Investing Activities:			
Additions to other property and equipment	1,310	594	417
Additions to drilling rig equipment	129	393	67
Proceeds from sale of drilling rigs and equipment	(369)	(244)	
Proceeds from sale of compressors	(188)		

Additions to investments	8	554	135
Proceeds from sale of investments	(124)	(159)	
Acquisition of trucking company, net of cash acquired		45	
Sale of non-oil and natural gas assets	(36)	(2)	(21)
Other			
Total other investing activities	730	1,181	598
Total cash used in investing activities	$ 7,922	$ 8,942	$ 6,921

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Bank Credit and Hedging Facilities

On November 2, 2007, we amended and restated our syndicated revolving bank credit facility to increase the borrowing base to $3.5 billion (with commitments of $3.0 billion) and extended the maturity to November 2012. We subsequently increased the commitments under the credit facility to $3.5 billion. As of December 31, 2007, we had $1.950 billion in outstanding borrowings under this facility and had utilized approximately $5 million of the facility for various letters of credit. Borrowings under the facility are secured by certain producing oil and natural gas properties and bear interest at our option of either (i) the greater of the reference rate of Union Bank of California, N.A., or the federal funds effective rate plus 0.50% or (ii) London Interbank Offered Rate (LIBOR), plus a margin that varies from 0.75% to 1.50% per annum according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are redetermined periodically. The unused portion of the facility is subject to a commitment fee that also varies according to our senior unsecured long-term debt ratings, from 0.125% to 0.30% per annum. Currently the commitment fee is 0.20% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals. Our subsidiaries, Chesapeake Exploration, L.L.C. and Chesapeake Appalachia, L.L.C., are the borrowers under our revolving bank credit facility and Chesapeake and all its other wholly-owned subsidiaries except minor subsidiaries are guarantors.

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.70 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.75 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.48 to 1 and our indebtedness to EBITDA ratio was 2.16 to 1 at December 31, 2007. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $75 million.

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

	Secured Hedging Facilities (a)					
	#1	#2	#3	#4	#5	#6
	($ in millions)					
Maximum permitted value of transactions under facility	$ 750	$ 500	$ 500	$ 250	$ 500	$ 500
Per annum exposure fee	1%	1%	1%	0.8%	0.8%	0.8%
Scheduled maturity date	2010	2010	2011	2012	2012	2012
Fair value of outstanding transactions, as of December 31, 2007	$ 1	$ (144)	$ (97)	$ (19)	$ (37)	$ (53)

(a) Chesapeake Exploration, L.L.C. is the named party to the facilities numbered 1-3 and Chesapeake Energy Corporation is the named party to the facilities numbered 4-6.

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Our revolving bank credit facility and secured hedging facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates and commitment fees in our bank credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, the bank facility and the secured hedging facilities do not contain provisions which would trigger an acceleration of amounts due under the facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

Senior Note Obligations

In addition to outstanding revolving bank credit facility borrowings discussed above, as of December 31, 2007, senior notes represented approximately $9.0 billion of our long-term debt and consisted of the following ($ in millions):

7.5% Senior Notes due 2013	$ 364
7.625% Senior Notes due 2013	500
7.0% Senior Notes due 2014	300
7.5% Senior Notes due 2014	300
7.75% Senior Notes due 2015	300
6.375% Senior Notes due 2015	600
6.625% Senior Notes due 2016	600
6.875% Senior Notes due 2016	670
6.5% Senior Notes due 2017	1,100
6.25% Euro-denominated Senior Notes due 2017 (a)	876
6.25% Senior Notes due 2018	600
6.875% Senior Notes due 2020	500
2.75% Contingent Convertible Senior Notes due 2035	690
2.5% Contingent Convertible Senior Notes due 2037	1,650
Discount on senior notes	(105)
Premium for interest rate derivatives	55
	$ 9,000

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.4603 to 1.00 as of December 31, 2007. See Note 10 of our accompanying consolidated financial statements for information on our related cross currency swap.

No scheduled principal payments are required under our senior notes until 2013, when $864 million is due. The holders of the 2.75% Contingent Convertible Senior Notes due 2035 may require us to repurchase, in cash, all or a portion of these notes on November 15, 2015, 2020, 2025 and 2030 at 100% of the principal amount of the notes. The holders of the 2.5% Contingent Convertible Senior Notes due 2037 may require us to repurchase, in cash, all or a portion of these notes on May 15, 2017, 2022, 2027 and 2032 at 100% of the principal amount of the notes.

As of December 31, 2007 and currently, debt ratings for the senior notes are Ba3 by Moody s Investor Service (negative outlook), BB by Standard & Poor s Ratings Services (positive outlook) and BB by Fitch Ratings (negative outlook).

Our senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. All of our wholly-owned subsidiaries, except minor subsidiaries, fully and unconditionally guarantee the notes jointly and severally on an unsecured basis. Senior notes issued before July 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital

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stock or subordinated indebtedness; make investments and other restricted payments; incur liens; enter into sale/leaseback transactions; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. Senior notes issued after June 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur certain secured indebtedness; enter into sale-leaseback transactions; and consolidate, merge or transfer assets. The debt incurrence covenants do not presently restrict our ability to borrow under or expand our secured credit facility. As of December 31, 2007, we estimate that secured commercial bank indebtedness of approximately $4.9 billion could have been incurred under the most restrictive indenture covenant.

Contractual Obligations

The table below summarizes our contractual obligations as of December 31, 2007 ($ in millions):

		Payments Due By Period			
	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 years
Long term debt:					
Principal	$ 11,000	$	$	$ 1,950	$ 9,050
Interest	5,581	520	1,040	1,040	2,981
Capital lease obligations	8	4	4		
Operating lease obligations	857	121	227	222	287
Asset retirement obligations (a)	236	8	16	4	208
Purchase obligations (b)	929	385	208	112	224
Unrecognized tax benefits (c)	133		69	64	
Standby letters of credit	6	6			
Total contractual cash obligations	$ 18,750	$ 1,044	$ 1,564	$ 3,392	$ 12,750

(a) Asset retirement obligations represent estimated discounted costs for future dismantlement and abandonment costs. These obligations are recorded as liabilities on our December 31, 2007 balance sheet.

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

(c) See Note 5 of the notes to our consolidated financial statements for a description of unrecognized tax benefits.

Chesapeake has commitments to purchase the production associated with the December 31, 2007 sale of a volumetric production payment that extends over a 15 year term at market prices at the time of production and the purchased gas will be resold. The obligations are as follows:

	Mmcfe
2008	19,858
2009	18,601
2010	18,043
2011	16,251
2012	15,322
After 2012	119,949
Total	208,024

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Hedging Activities

Oil and Natural Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. Executive management is involved in all risk management activities and the Board of Directors reviews the company s hedging program at its quarterly Board meetings. We believe we have sufficient internal controls to prevent unauthorized hedging. As of December 31, 2007, our oil and natural gas derivative instruments were comprised of swaps, basis protection swaps, knockout swaps, cap-swaps, call options and collars. Item 7A Quantitative and Qualitative Disclosures About Market Risk contains a description of each of these instruments. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

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

Mark-to-market positions under oil and natural gas hedging contracts fluctuate with commodity prices. As described above under *Bank Credit and Hedging Facilities*, we may be required to deliver cash collateral or other assurances of performance if our payment obligations to our hedging counterparties exceed levels stated in our contracts. Our realized and unrealized gains and losses on oil and natural gas derivatives during 2007, 2006 and 2005 were as follows:

	Years Ended December 31,		
	2007	2006	2005
		($ in millions)	
Oil and natural gas sales	$ 4,795	$ 3,870	$ 3,633
Realized gains on oil and natural gas derivatives	1,203	1,254	(401)
Unrealized gains (losses) on non-qualifying oil and natural gas derivatives	(252)	184	117
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(122)	311	(76)
Total oil and natural gas sales	$ 5,624	$ 5,619	$ 3,273

Changes in the fair value of oil and natural gas derivative instruments designated as cash flow hedges, to the extent effective in offsetting cash flows attributable to the hedged commodities, and locked-in gains and losses of derivative contracts are recorded in accumulated other comprehensive income and are transferred to earnings in the month of related production. These unrealized gains (losses), net of related tax effects, totaled $53 million, $546 million and ($271) million as of December 31, 2007, 2006 and 2005, respectively. Based upon the market prices at December 31, 2007, we expect to transfer to earnings approximately $127 million of the net gain included in the balance of accumulated other comprehensive income during the next 12 months. A detailed explanation of accounting for oil and natural gas derivatives under SFAS 133 appears under Application of Critical Accounting Policies Hedging elsewhere in this Item 7.

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The estimated fair values of our oil and natural gas derivative instruments as of December 31, 2007 and 2006 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	December 31, 2007	December 31, 2006
	($ in millions)	
Derivative assets (liabilities):		
Fixed-price natural gas swaps	$ (54)	$ 1
Natural gas basis protection swaps	151	187
Fixed-price natural gas knockout swaps	108	122
Fixed-price natural gas counter-swaps		(5)
Natural gas call options (a)	(230)	(5)
Fixed-price natural gas collars (b)	4	(7)
Fixed-price oil swaps	(110)	28
Fixed-price oil cap-swaps	(17)	24
Fixed-price oil knockout swaps	(125)	
Oil call options (c)	(96)	
Estimated fair value	$ (369)	$ 345

(a) After adjusting for $255 million and $15 million of unrealized premiums, the cumulative unrealized gain related to these call options as of December 31, 2007 and 2006 was $25 million and $10 million, respectively.

(b) After adjusting for $8 million of unrealized discount, the cumulative unrealized loss related to these collars as of December 31, 2007 was $4 million.

(c) After adjusting for $29 million of unrealized premiums, the cumulative unrealized loss related to these call options as of December 31, 2007 was $67 million.

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

	December 31, 2007	December 31, 2006	December 31, 2005
		($ in millions)	
Fair value of contracts outstanding, as of January 1	$ 345	$ (946)	$ 38
Change in fair value of contracts	972	3,423	(771)
Fair value of contracts when entered into	(295)	(32)	(614)
Contracts realized or otherwise settled	(1,203)	(1,254)	401
Fair value of contracts when closed	(188)	(846)	
Fair value of contracts outstanding, as of December 31	$ (369)	$ 345	$ (946)

Interest Rate Derivatives

We use interest rate derivatives to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value are recorded on the consolidated balance sheets as assets (liabilities), and the debt s carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

Gains or losses from derivative transactions are reflected as adjustments to interest expense on the consolidated statements of operations. Realized gains (losses) included in interest expense were ($1) million, ($2) million and $5 million in 2007, 2006 and 2005, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as fair value hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within interest expense. Unrealized gains (losses) included in interest expense were ($40) million, $2 million and $2 million in 2007, 2006 and 2005, respectively. A detailed explanation of accounting for interest rate derivatives under SFAS 133 appears under Application of Critical Accounting Policies Hedging elsewhere in this Item 7.

Foreign Currency Derivatives

On December 6, 2006, we issued 600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the Euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. A detailed explanation of accounting for foreign currency derivatives under SFAS 133 appears under Application of Critical Accounting Policies Hedging elsewhere in this Item 7.

Results of Operations

General. For the year ended December 31, 2007, Chesapeake had net income of $1.451 billion, or $2.62 per diluted common share, on total revenues of $7.800 billion. This compares to net income of $2.003 billion, or $4.35 per diluted common share, on total revenues of $7.326 billion during the year ended December 31, 2006, and net income of $948 million, or $2.51 per diluted common share, on total revenues of $4.665 billion during the year ended December 31, 2005.

Oil and Natural Gas Sales. During 2007, oil and natural gas sales were $5.624 billion compared to $5.619 billion in 2006 and $3.273 billion in 2005. In 2007, Chesapeake produced and sold 714.3 bcfe of oil and natural gas at a weighted average price of $8.40 per mcfe, compared to 578.4 bcfe in 2006 at a weighted average price of $8.86 per mcfe, and 468.6 bcfe in 2005 at a weighted average price of $6.90 per mcfe (weighted average prices for all years discussed exclude the effect of unrealized gains or (losses) on derivatives of ($374) million, $495 million and $41 million in 2007, 2006 and 2005, respectively). The decrease in prices in 2007 resulted in a decrease in revenue of $329 million and increased production resulted in a $1.203 billion increase, for a total increase in revenues of $874 million (excluding unrealized gains or losses on oil and natural gas derivatives). The increase in production from period to period was primarily generated from the drillbit.

For 2007, we realized an average price per barrel of oil of $67.50, compared to $59.14 in 2006 and $47.77 in 2005 (weighted average prices for all years discussed exclude the effect of unrealized gains or losses on derivatives). Natural gas prices realized per mcf (excluding unrealized gains or losses on derivatives) were $8.14, $8.76 and $6.78 in 2007, 2006 and 2005, respectively. Realized gains or losses from our oil and natural gas derivatives resulted in a net increase in oil and natural gas revenues of $1.203 billion or $1.68 per mcfe in 2007, a net increase of $1.254 billion or $2.17 per mcfe in 2006 and a net decrease of $401 million or $0.86 per mcfe in 2005.

A change in oil and natural gas prices has a significant impact on our oil and natural gas revenues and cash flows. Assuming 2007 production levels, a change of $0.10 per mcf of natural gas sold would result in an increase or decrease in revenues and cash flow of approximately $65 million and $63 million, respectively, and a change of $1.00 per barrel of oil sold would result in an increase or decrease in revenues and cash flow of approximately $10 million and $9 million, respectively, without considering the effect of hedging activities.

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The following table shows our production by region for 2007, 2006 and 2005:

	Years Ended December 31,					
	2007		2006		2005	
	Mmcfe	Percent	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	373,941	52%	315,173	55%	297,773	64%
Barnett Shale	93,463	13	44,482	7	17,409	4
Appalachian Basin	47,922	7	45,031	8	5,878	1
Permian and Delaware Basins	64,897	9	48,510	8	42,958	9
Ark-La-Tex	55,811	8	46,009	8	40,707	9
South Texas and Texas Gulf Coast	78,228	11	79,178	14	63,852	13
Total Production	714,262	100%	578,383	100%	468,577	100%

Natural gas production represented approximately 92% of our total production volume on an equivalent basis in 2007, compared to 91% in 2006 and 90% in 2005.

Oil and Natural Gas Marketing Sales and Operating Expenses. Oil and natural gas marketing activities are substantially for third parties who are owners in Chesapeake-operated wells. Chesapeake realized $2.040 billion in oil and natural gas marketing sales to third parties in 2007, with corresponding oil and natural gas marketing expenses of $1.969 billion, for a net margin before depreciation of $71 million. This compares to sales of $1.577 billion and $1.392 billion, expenses of $1.522 billion and $1.358 billion, and margins before depreciation of $55 million and $35 million in 2006 and 2005, respectively. The net margin increase in 2007 and 2006 is primarily due to an increase in volumes and prices related to oil and natural gas marketing sales.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our leased or owned drilling and oilfield trucking operations. These operations have grown as a result of assets and businesses we acquired in 2006 and 2007. Chesapeake recognized $136 million in service operations revenue in 2007 with corresponding service operations expenses of $94 million, for a net margin before depreciation of $42 million. This compares to revenue of $130 million, expenses of $68 million and a net margin before depreciation of $62 million in 2006. During 2005, service operations revenues and expenses for third parties were insignificant.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $640 million in 2007, compared to $490 million and $317 million in 2006 and 2005, respectively. On a unit-of-production basis, production expenses were $0.90 per mcfe in 2007 compared to $0.85 and $0.68 per mcfe in 2006 and 2005, respectively. The increase in 2007 was primarily due to higher third-party field service costs, fuel costs and personnel costs. We expect that production expenses per mcfe produced for 2008 will range from $0.90 to $1.00.

Production Taxes. Production taxes were $216 million in 2007 compared to $176 million in 2006 and $208 million in 2005. On a unit-of-production basis, production taxes were $0.30 per mcfe in 2007 compared to $0.31 per mcfe in 2006 and $0.44 per mcfe in 2005. In 2006, $2 million was accrued for certain severance tax claims and was then offset by a subsequent reversal of the cumulative $12 million accrual for such severance tax claims as a result of their dismissal. After adjusting for these items, there was an increase of $30 million in production taxes from 2006 to 2007. The $30 million increase is mostly due to an increase in production of 136 bcfe.

In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil and natural gas prices are higher. We expect production taxes for 2008 to range from $0.32 to $0.37 per mcfe produced based on a NYMEX price of $76.49 per barrel of oil and natural gas wellhead prices ranging from $7.40 to $8.40 per mcf.

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General and Administrative Expense. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our oil and natural gas properties (see Note 11 of notes to consolidated financial statements), were $243 million in 2007, $139 million in 2006 and $64 million in 2005. General and administrative expenses were $0.34, $0.24 and $0.14 per mcfe for 2007, 2006 and 2005, respectively. The increase in 2007, 2006 and 2005 was the result of the company s overall growth as well as cost and wage inflation. Included in general and administrative expenses is stock-based compensation of $58 million in 2007, $27 million in 2006 and $15 million in 2005. The increase was mainly due to a higher number of unvested restricted shares outstanding during 2007 compared to 2006 and 2005. We anticipate that general and administrative expenses for 2008 will be between $0.33 and $0.37 per mcfe produced, including stock-based compensation ranging from $0.10 to $0.12 per mcfe produced.

Our stock-based compensation for employees and non-employee directors is in the form of restricted stock. Prior to 2004, stock-based compensation awards were only in the form of stock options. Employee stock-based compensation awards generally vest over a period of four or five years. Our non-employee director awards vest over a period of three years.

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

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

Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $262 million, $161 million and $102 million of internal costs in 2007, 2006 and 2005, respectively, directly related to our oil and natural gas property acquisition, exploration and development efforts.

Oil and Natural Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and natural gas properties was $1.835 billion, $1.359 billion and $894 million during 2007, 2006 and 2005, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs, and the related underlying reserves in the periods presented, was $2.57, $2.35 and $1.91 in 2007, 2006 and 2005, respectively. The increase in the average rate from $2.35 in 2006 to $2.57 in 2007 is primarily the result of higher drilling costs, higher costs associated with acquisitions and the recognition of the tax effect of acquisition costs in excess of tax basis acquired in certain corporate acquisitions. We expect the 2008 DD&A rate to be between $2.50 and $2.70 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $154 million in 2007, compared to $104 million in 2006 and $51 million in 2005. The average D&A rate per mcfe was $0.22, $0.18 and $0.11 in 2007, 2006 and 2005, respectively. The increases in 2007 and 2006 were primarily the result of higher depreciation costs resulting from the acquisition of various gathering facilities, the construction of new buildings at our corporate headquarters complex and at various field office locations and additional information technology equipment and software. In 2006, increases were also attributed to the acquisition of compression equipment and drilling rigs. The overall increase in 2007 was partially mitigated by various sale/leaseback transactions throughout 2007 related to certain of our compressors and drilling rigs. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 15 to 39 years, gathering facilities are depreciated over 20 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to seven years. To the extent company-owned drilling rigs were used to drill our wells in 2005 and 2006, a substantial portion of the rig depreciation was capitalized in oil and natural gas properties as exploration or development costs. As a result of the sale/leaseback of our company-owned rigs, we did not recognize rig depreciation in 2007. We expect 2008 depreciation and amortization of other assets to be between $0.20 and $0.24 per mcfe produced.

Employee Retirement Expense. Our President and Chief Operating Officer, Tom L. Ward, resigned as a director, officer and employee of the company effective February 10, 2006. Mr. Ward s Resignation Agreement provided for the immediate vesting of all of his unvested equity awards, which consisted of options to purchase 724,615 shares of Chesapeake s common stock at an average exercise price of $8.01 per share and 1,291,875 shares of restricted common stock. As a result of this vesting, we incurred an expense of $55 million in 2006.

Interest and Other Income. Interest and other income was $15 million, $26 million and $10 million in 2007, 2006 and 2005, respectively. The 2007 income consisted of $8 million of interest income and $7 million of miscellaneous income. Income related to equity investments was not significant in 2007. The 2006 income consisted of $5 million of interest income, $10 million of income related to equity investments, a $5 million gain on sale of assets and $6 million of miscellaneous income. The 2005 income consisted of $3 million of interest income, $2 million of income related to equity investment, and $5 million of miscellaneous income.

Interest Expense. Interest expense increased to $406 million in 2007 compared to $301 million in 2006 and $220 million in 2005 as follows:

	Years Ended December 31,		
	2007	2006	2005
	($ in millions)		
Interest expense on senior notes and revolving bank credit facility	$ 616	$ 472	$ 300
Capitalized interest	(269)	(179)	(79)
Amortization of loan discount and other	17	7	6
Unrealized (gain) loss on interest rate derivatives	41	(1)	(2)
Realized (gain) loss on interest rate derivatives	1	2	(5)
Total interest expense	$ 406	$ 301	$ 220
Average long-term borrowings	$ 8,224	$ 6,278	$ 3,948

Interest expense, excluding unrealized (gains) losses on derivatives and net of amounts capitalized, was $0.51 per mcfe in 2007 compared to $0.52 per mcfe in 2006 and $0.47 per mcfe in 2005. We expect interest expense for 2008 to be between $0.50 and $0.55 per mcfe produced (before considering the effect of interest rate derivatives).

Gain on Sale of Investments. 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. In 2006, Chesapeake sold its investment in publicly-traded Pioneer Drilling Company common stock, realizing proceeds of $159 million and a gain of $117 million. We owned 17% of the common stock of Pioneer, which we began acquiring in 2003.

Loss on Repurchases or Exchanges of Chesapeake Senior Notes. In 2005, we repurchased or exchanged $564 million of Chesapeake debt in order to re-finance a portion of our long-term debt at a lower rate of interest and recognized a loss of $70 million. No such purchases or exchanges were completed in 2007 or 2006.

Income Tax Expense. 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. Most of the 2007 income tax expense was deferred and we expect most of our 2008 income tax expense to be deferred.

Loss on Conversion/Exchange of Preferred Stock. Loss on conversion/exchange of preferred stock was $128 million in 2007 compared to $10 million in 2006 and $26 million in 2005. The loss on the exchanges represented the excess of the fair value of the common stock issued over the fair value of the securities issuable pursuant to the original conversion terms. See Note 9 of notes to the consolidated financial statements in Item 8 for further detail regarding these transactions.

Application of Critical Accounting Policies

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

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

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

Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the consolidated balance sheet as assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Any change in the fair value resulting from ineffectiveness, as defined by SFAS 133, is recognized immediately

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in oil and natural gas sales. For derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value, as well as the offsetting changes in the estimated fair value of the hedged item attributable to the hedged risk, are recognized currently in earnings. Differences between the changes in the fair values of the hedged item and the derivative instrument, if any, represent gains or losses on ineffectiveness and are reflected currently in interest expense. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Changes in fair value of contracts that do not qualify as hedges or are not designated as hedges are also recognized currently in earnings. See Hedging Activities above and Item 7A Quantitative and Qualitative Disclosures About Market Risk for additional information regarding our hedging activities.

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

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

Due to the volatility of oil and natural gas prices and, to a lesser extent, interest rates and foreign exchange rates, the company s financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2007, 2006 and 2005, the net market value of our derivatives was a liability of $375 million, an asset of $293 million and a liability of $968 million, respectively. The derivatives that we acquired in our CNR acquisition represented $184 million, $254 million and $661 million of liability at December 31, 2007, 2006 and 2005.

Oil and Natural Gas Properties. The accounting for our business is subject to special accounting rules that are unique to the oil and natural gas industry. There are two allowable methods of accounting for oil and natural gas business activities: the successful efforts method and the full-cost method. Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities.

Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion, amortization and impairment of oil and natural gas properties are generally calculated on a well by well or lease or field basis versus the aggregated full cost pool basis. Additionally, gain or loss is generally recognized on all sales of oil and natural gas properties under the successful efforts method. As a result, our financial statements will differ from companies that apply the successful efforts method since we will generally reflect a higher level of capitalized costs as well as a higher oil and natural gas depreciation, depletion and amortization rate, and we will not have exploration expenses that successful efforts companies frequently have.

Under the full-cost method, capitalized costs are amortized on a composite unit-of-production method based on proved oil and natural gas reserves. If we maintain the same level of production year over year, the

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depreciation, depletion and amortization expense may be significantly different if our estimate of remaining reserves changes significantly. Proceeds from the sale of properties are accounted for as reductions of capitalized costs unless such sales involve a significant change in the relationship between costs and the value of proved reserves or the underlying value of unproved properties, in which case a gain or loss is recognized. The costs of unproved properties are excluded from amortization until the properties are evaluated. We review all of our unevaluated properties quarterly to determine whether or not and to what extent proved reserves have been assigned to the properties, and otherwise if impairment has occurred. Unevaluated properties are grouped by major producing area where individual property costs are not significant and are assessed individually when individual costs are significant.

We review the carrying value of our oil and natural gas properties under the full-cost accounting rules of the Securities and Exchange Commission on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In calculating future net revenues, current prices and costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. Two primary factors impacting this test are reserve levels and current prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of natural gas and oil reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense. Under SEC regulations, the excess above the ceiling is not expensed (or is reduced) if, subsequent to the end of the period, but prior to the release of the financial statements, oil and natural gas prices increase sufficiently such that an excess above the ceiling would have been eliminated (or reduced) if the increased prices were used in the calculations.

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

As of December 31, 2007, approximately 79% of our proved reserves were evaluated by independent petroleum engineers, with the balance evaluated by our internal reservoir engineers. In addition, our internal engineers review and update our reserves on a quarterly basis. All reserve estimates are prepared based upon a review of production histories and other geologic, economic, ownership and engineering data we developed. Additional information about our 2007 year-end reserve evaluation is included under Oil and Natural Gas Reserves in Item 1 Business.

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

Income Taxes. As part of the process of preparing the consolidated financial statements, we are required to estimate the federal and state income taxes in each of the jurisdictions in which Chesapeake operates. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as derivative instruments, depreciation, depletion and

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amortization, and certain accrued liabilities for tax and accounting purposes. These differences and our net operating loss carryforwards result in deferred tax assets and liabilities, which are included in our consolidated balance sheet. We must then assess, using all available positive and negative evidence, the likelihood that the deferred tax assets will be recovered from future taxable income. If we believe that recovery is not likely, we must establish a valuation allowance. Generally, to the extent Chesapeake establishes a valuation allowance or increases or decreases this allowance in a period, we must include an expense or reduction of expense within the tax provisions in the consolidated statement of operations.

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

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

If (a) natural gas and oil prices were to decrease significantly below present levels (and if such decreases were considered other than temporary), (b) exploration, drilling and operating costs were to increase significantly beyond current levels, or (c) we were confronted with any other significantly negative evidence pertaining to our ability to realize our NOL carryforwards prior to their expiration, we may be required to provide a valuation allowance against our deferred tax assets. As of December 31, 2007, we had deferred tax assets of $409 million.

FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109,* provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 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. Based on this guidance, we regularly analyze tax positions taken or expected to be taken in a tax return based on the threshold condition prescribed under FIN 48. Tax positions that do not meet or exceed this threshold condition are considered uncertain tax positions. We accrue interest related to these uncertain tax positions which is recognized in interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses. Additional information about uncertain tax positions appears in Income Taxes Item 1-Business.

Accounting for Business Combinations. Our business has grown substantially through acquisitions and our business strategy is to continue to pursue acquisitions as opportunities arise. We have accounted for all of our business combinations using the purchase method, which is the only method permitted under SFAS 141, *Accounting for Business Combinations*. The accounting for business combinations is complicated and involves the use of significant judgment.

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

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The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if any, is allocated as a pro rata reduction of the amounts that otherwise would have been assigned to certain acquired assets.

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

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

Disclosures About Effects of Transactions with Related Parties

As of December 31, 2007, we had accrued accounts receivable from our CEO, Aubrey K. McClendon, of $18 million representing joint interest billings from December 2007 which were invoiced and timely paid in January 2008. Since Chesapeake was founded in 1989, Mr. McClendon has acquired working interests in virtually all of our oil and natural gas properties by participating in our drilling activities under the terms of the Founder Well Participation Program (FWPP) described below. Joint interest billings to him are settled in cash immediately upon delivery of a monthly joint interest billing.

Under the FWPP, approved by our shareholders in June 2005, Mr. McClendon (and our co-founder and former COO, Tom L. Ward, prior to August 10, 2006) may elect to participate in all or none of the wells drilled by or on behalf of Chesapeake during a calendar year, but he is not allowed to participate only in selected wells. A participation election is required to be received by the Compensation Committee of Chesapeake s Board of Directors not less than 30 days prior to the start of each calendar year. His participation is permitted only under the terms outlined in the Founder Well Participation Program, which, among other things, limits his individual participation to a maximum working interest of 2.5% in a well and prohibits participation in situations where Chesapeake s working interest would be reduced below 12.5% as a result of his participation. In addition, the company is reimbursed for costs associated with leasehold acquired by Mr. McClendon as a result of his well participation. Mr. Ward s participation in the Founder Well Participation Program terminated on August 10, 2006.

As disclosed in Note 8, in 2007, Chesapeake had revenues of $1.1 billion from oil and natural gas sales to Eagle Energy Partners I, L.P., a former affiliated entity. We sold our 33% limited partnership interest in Eagle Energy in June 2007.

Recently Issued Accounting Standards

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

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments an amendment of FASB Statements No. 133 and 140*. SFAS 155 permits an entity to measure at fair value any financial instrument that contains an embedded derivative that otherwise would require bifurcation. This statement is effective for all financial instruments we acquire or issue after December 31, 2006. Adoption of SFAS 155 did not have a material effect on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. However, on February 12, 2008, the FASB issued FSP No. FAS 157-2, *Effective Date of FASB Statement No. 157* which delays the effective date of SFAS 157 for all nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). This FSP partially defers the effective date of SFAS 157 to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years for items within the scope of the FSP. We are currently assessing the impact, if any, the adoption of this statement will have on our financial position, results of operations or cash flows.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. This statement permits entities to choose to measure many financial instruments and certain other items at fair value. This statement expands the use of fair value measurement and applies to entities that elect the fair value option. The fair value option established by this statement permits all entities to choose to measure eligible items at fair value at specified election dates. This statement is effective as of the beginning of the first fiscal year that begins after November 15, 2007. We are currently assessing the impact, if any, the adoption of this statement will have on our financial position, results of operations or cash flows.

In November 2007, the FASB issued its preliminary views on financial instruments with characteristics of equity as a step preceding the development of a proposed Statement of Financial Accounting Standards. Such a standard would affect accounting for convertible debt instruments that may be settled in cash upon conversion, including partial cash settlements. This accounting could increase the amount of interest expense required to be recognized with respect to such instruments and, thus, lower reported net income and net income per share of issuers of such instruments. Issuers would have to account for the liability and equity components of the instrument separately and in a manner that reflects interest expense at the interest rate of similar nonconvertible debt. We have two debt series that would be affected by such a standard, our 2.75% Contingent Convertible Senior Notes due 2035 and our 2.5% Contingent Convertible Senior Notes due 2037. If the FASB adopts the statement, it is expected to be effective for fiscal years starting after December 15, 2007. Companies would have to apply the statement retrospectively to both existing and new instruments that fall within the scope of the guidance.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51*. This statement requires an entity to separately disclose non-controlling interests as a separate component of equity in the balance sheet and clearly identify on the face of the income statement net income related to non-controlling interests. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2008. We are currently assessing the impact, if any, the adoption of this statement will have on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations*. This statement requires assets acquired and liabilities assumed to be measured at fair value as of the acquisition date, acquisition-related costs incurred prior to the acquisition to be expensed and contractual contingencies to be recognized at fair value as of the acquisition date. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2008. We are currently assessing the impact, if any, the adoption of this statement will have on our financial position, results of operations or cash flows.

Forward-Looking Statements

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements give our current expectations or forecasts of future events. They include statements regarding oil and natural gas reserve

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estimates, planned capital expenditures, the drilling of oil and natural gas wells and future acquisitions, expected oil and natural gas production, cash flow and anticipated liquidity, business strategy and other plans and objectives for future operations and expected future expenses. Statements concerning the fair values of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility.

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

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

drilling and operating risks,

adverse effects of governmental and environmental regulation, and

losses possible from pending or future litigation.

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

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

Oil and Natural Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of December 31, 2007, our oil and natural gas derivative instruments were comprised of swaps, basis protection swaps, knockout swaps, cap-swaps, call options and collars. These instruments allow us to predict with greater certainty the effective oil and natural gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe

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our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

For swap instruments, Chesapeake receives a fixed price for the hedged commodity and pays a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

Basis protection swaps are arrangements that guarantee a price differential for oil or natural gas from a specified delivery point. For Mid-Continent basis protection swaps, which have negative differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. For Appalachian Basin basis protection swaps, which have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.

For knockout swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty s exposure to zero, in any given month, if the floating market price is lower than certain pre-determined knockout prices.

For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a cap limiting the counterparty s exposure. In other words, there is no limit to Chesapeake s exposure but there is a limit to the downside exposure of the counterparty.

For call options, Chesapeake receives a premium from the counterparty in exchange for the sale of a call option. If the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess. If the market price settles below the fixed price of the call option, no payment is due from Chesapeake.

Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.

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

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

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

Gains or losses from certain derivative transactions are reflected as adjustments to oil and natural gas sales on the consolidated statements of operations. Realized gains (losses) are included in oil and natural gas sales in the month of related production. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within oil and natural gas sales. Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and natural gas sales as unrealized gains (losses). The components of oil and natural gas sales for the years ended December 31, 2007, 2006 and 2005 are presented below.

	Years Ended December 31,		
	2007	2006	2005
		($ in millions)	
Oil and natural gas sales	$ 4,795	$ 3,870	$ 3,633
Realized gains on oil and natural gas derivatives	1,203	1,254	(401)
Unrealized gains (losses) on non-qualifying oil and natural gas derivatives	(252)	184	117
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(122)	311	(76)
Total oil and natural gas sales	$ 5,624	$ 5,619	$ 3,273

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As of December 31, 2007, we had the following open oil and natural gas derivative instruments (excluding derivatives assumed through our acquisition of CNR in November 2005) designed to hedge a portion of our oil and natural gas production for periods after December 2007:

	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums ($ in millions)	Fair Value at December 31, 2007 ($ in millions)
Natural Gas (bbtu):								
Swaps:								
1Q 2008	110,665	$ 8.56	$	$	$	Yes	$	$ 118
2Q 2008	57,425	7.93				Yes		18
3Q 2008	56,133	8.06				Yes		11
4Q 2008	53,770	8.62				Yes		14
2009	57,062	8.22				Yes		(17)
2010	10,199	7.86				Yes		(7)
2011 2022	148	7.65				Yes		
Basis Protection Swaps (Mid-Continent):								
1Q 2008	33,215				(0.30)	No		21
2Q 2008	26,845				(0.25)	No		24
3Q 2008	27,140				(0.25)	No		20
4Q 2008	31,410				(0.28)	No		30
2009	86,600				(0.29)	No		58
2012	10,700				(0.34)	No		2
Basis Protection Swaps (Appalachian Basin):								
1Q 2008	5,622				0.32	No		(1)
2Q 2008	5,783				0.33	No		
3Q 2008	5,763				0.33	No		
4Q 2008	5,840				0.33	No		
2009	16,912				0.28	No		(1)
2010	10,199				0.26	No		(1)
2011	12,086				0.25	No		(1)
2012 2022	134				0.11	No		
Other Swaps:								
1Q 2008	6,370	$ 7.89	$	$	$	No	$	$ 3
2Q 2008	6,050	8.47				No		5
3Q 2008	4,600	8.73				No		4
4Q 2008	4,600	8.73				No		2
2009 (a)	22,750	8.73				No		(14)
2010 (a)	18,250	8.73				No		(16)
Knockout Swaps:								
1Q 2008	8,190	10.83	5.94			No		27
2Q 2008	60,380	9.15	6.21			No		52
3Q 2008	62,560	9.32	6.21			No		28
4Q 2008	55,240	9.91	6.20			No		19
2009	152,350	9.33	6.13			No		(18)
Call Options:								
1Q 2008	9,600			10.27		No	16	
2Q 2008	31,850			10.25		No	20	(4)
3Q 2008	32,200			10.25		No	21	(10)
4Q 2008	30,980			10.26		No	20	(21)
2009	119,500			11.12		No	73	(66)
2010	83,950			10.00		No	56	(69)

2011	65,700		10.11	No	46	(55)
2012	7,320		11.00	No	3	(5)
Collars:						
1Q 2008	7,590	7.32	9.17	Yes		2
2Q 2008	2,730	7.50	9.68	Yes		1
3Q 2008	2,760	7.50	9.68	Yes		1
4Q 2008	2,760	7.50	9.68	Yes		
Other Collars:						
1Q 2008	10,920	7.40/5.46	9.35	No		4
2009	27,375	7.97/5.83	11.18	No	(8)	5
Total Natural Gas					247	163

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	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums ($ in millions)	Fair Value at December 31, 2007 ($ in millions)
Oil (mbbls):								
Swaps:								
1Q 2008	1,152	70.32				Yes		(29)
2Q 2008	1,183	70.25				Yes		(28)
3Q 2008	1,196	69.94				Yes		(26)
4Q 2008	828	69.47				Yes		(17)
2009	548	67.77				Yes		(10)
Knockout Swaps:								
1Q 2008	546	74.97	53.58			No		(11)
2Q 2008	546	75.16	53.58			No		(10)
3Q 2008	552	75.29	53.58			No		(10)
4Q 2008	736	76.69	55.19			No		(11)
2009	7,483	82.62	58.12			No		(63)
2010	3,650	86.25	60.00			No		(20)
Cap-Swaps:								
1Q 2008	273	77.60	55.00			No		(5)
2Q 2008	273	77.60	55.00			No		(4)
3Q 2008	276	77.60	55.00			No		(4)
4Q 2008	276	77.60	55.00			No		(4)
Call Options:								
1Q 2008	455				81.00	No	1	(7)
2Q 2008	637				83.57	No	2	(8)
3Q 2008	644				83.57	No	2	(8)
4Q 2008	828				81.67	No	3	(11)
2009	2,190				75.00	No	12	(35)
2010	1,825				75.00	No	9	(27)
Total Oil							29	(348)
Total Natural Gas and Oil							$ 276	$ (185)

(a) These include options to extend an existing swap for an additional 12 months at 50,000 mmbtu/day at $8.73/mmbtu. The options are callable by the counterparty in March 2009 and March 2010.

In 2006 and 2007, Chesapeake lifted or assigned a portion of its 2008 through 2022 hedges and has approximately $215 million of deferred hedging gains as of December 31, 2007. These gains have been recorded in accumulated other comprehensive income or as an unrealized gain in oil and natural gas sales. For amounts originally recorded in other comprehensive income, the gain will be recognized in oil and natural gas sales in the month of the hedged production.

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

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Pursuant to Statement of Financial Accounting Standards No. 149, *Amendment of SFAS 133 on Derivative Instruments and Hedging Activities*, the derivative instruments assumed in connection with the CNR acquisition are deemed to contain a significant financing element and all cash flows associated with these positions are reported as financing activity in the statement of cash flows for the periods in which settlement occurs.

The following details the assumed CNR derivatives remaining as of December 31, 2007:

	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	SFAS 133 Hedge	Fair Value at December 31, 2007 ($ in millions)
Natural Gas (bbtu):						
Swaps:						
1Q 2008	9,555	$ 4.68	$	$	Yes	$ (25)
2Q 2008	9,555	4.68			Yes	(28)
3Q 2008	9,660	4.68			Yes	(30)
4Q 2008	9,660	4.66			Yes	(35)
2009	18,250	5.18			Yes	(57)
Collars:						
2009	3,650		4.50	6.00	Yes	(9)
Total Natural Gas						$ (184)

We have established the fair value of all derivative instruments using estimates of fair value reported by our counterparties and subsequently evaluated internally using established index prices and other sources. The actual contribution to our future results of operations will be based on the market prices at the time of settlement and may be more or less than the fair value estimates used at December 31, 2007.

Based upon the market prices at December 31, 2007, we expect to transfer approximately $127 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to earnings during the next 12 months in the related month of production. All transactions hedged as of December 31, 2007 are expected to mature by December 31, 2022.

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

	2007	December 31, 2006 ($ in millions)	2005
Fair value of contracts outstanding, as of January 1	$ 345	$ (946)	$ 38
Change in fair value of contracts	972	3,423	(771)
Fair value of contracts when entered into	(295)	(32)	(614)
Contracts realized or otherwise settled	(1,203)	(1,254)	401
Fair value of contracts when closed	(188)	(846)	
Fair value of contracts outstanding, as of December 31	$ (369)	$ 345	$ (946)

The change in the fair value of our derivative instruments since January 1, 2007 resulted from new contracts entered into, the settlement of derivatives for a realized gain, as well as an increase in natural gas prices. Derivative instruments reflected as current in the consolidated balance sheet represent the estimated fair value of derivative instrument settlements scheduled to occur over the subsequent twelve-month period based on market prices for oil and natural gas as of the consolidated balance sheet date. The derivative settlement amounts are not due and payable until the month in which the related underlying hedged transaction occurs.

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Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates. As of December 31, 2007, the fair value of the fixed-rate long-term debt has been estimated based on quoted market prices.

	2008	2009	2010	2011	2012	Thereafter	Total	Fair Value
					Years of Maturity ($ in billions)			
Liabilities:								
Long-term debt fixed-rate (a)	$	$	$	$	$	$ 9.050	$ 9.050	$ 9.179
Average interest rate						5.8%	5.8%	5.8%
Long-term debt variable rate	$	$	$	$	$ 1.950	$	$ 1.950	$ 1.950
Average interest rate					5.8%		5.8%	5.8%

(a) This amount does not include the discount included in long-term debt of ($105) million and the impact of interest rate derivatives of $55 million.

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

Interest Rate Derivatives

We use interest rate derivatives to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value are recorded on the consolidated balance sheets as assets (liabilities), and the debt s carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

Gains or losses from derivative transactions are reflected as adjustments to interest expense in the consolidated statements of operations. Realized gains (losses) included in interest expense were ($1) million, ($2) million and $5 million in 2007, 2006 and 2005, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as fair value hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within interest expense. Unrealized gains (losses) included in interest expense were ($40) million, $2 million and $2 million in 2007, 2006 and 2005, respectively.

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As of December 31, 2007, the following derivatives were outstanding:

	Notional Amount ($ in millions)	Weighted Average Fixed Rate	Weighted Average Floating Rate	Weighted Average Cap/Floor Rate	Fair Value Hedge	Net Premiums ($ in millions)	Fair Value ($ in millions)
Fixed to Floating Swaps:							
July 2005 January 2018	$ 1,500	6.750%	6 month LIBOR plus 164 basis points		Yes	$	$ 28
September 2004 July 2013	$ 325	7.942%	6 month LIBOR plus 297 basis points		No		9
Floating to Fixed Swaps:							
August 2007 July 2010	$ 750	4.803%	3 month LIBOR		No		(14)
Call Options:							
August 2007 February 2008	$ 750	6.875%			No	6	(32)
Collars:							
August 2007 August 2010	$ 1,075			5.37% 4.32%	No		(20)
						$ 6	$ (29)

In 2007, we sold call options on six of our interest rate swaps and received $11 million in premiums. Two of the options expired unexercised in 2007.

In 2007, we closed ten interest rate swaps for a gain totaling $18 million. These interest rate swaps were designated as fair value hedges, and the settlement amounts received will be amortized as a reduction to realized interest expense over the remaining term of the related senior notes.

Foreign Currency Derivatives

On December 6, 2006, we issued 600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the Euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties will pay Chesapeake 19 million and Chesapeake will pay the counterparties $30 million, which will yield an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake 600 million and Chesapeake will pay the counterparties $800 million. The terms of the cross currency swap were based on the dollar/euro exchange rate on the issuance date of $1.3325 to 1.00. Through the cross currency swap, we have eliminated any potential variability in Chesapeake s expected cash flows related to changes in foreign exchange rates and therefore the swap qualifies as a cash flow hedge under SFAS 133. The euro-denominated debt is recorded in notes payable ($876 million at December 31, 2007) using an exchange rate of $1.4603 to 1.00. The fair value of the cross currency swap is recorded on the consolidated balance sheet as an asset of $23 million at December 31, 2007. The translation adjustment to notes payable is completely offset by the fair value of the cross currency swap and therefore there is no impact to the consolidated statement of operations. The remaining value of the cross currency swap related to future interest payments is reported in other comprehensive income.

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

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CHESAPEAKE ENERGY CORPORATION

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

Management has performed an assessment of the effectiveness of the Company s internal control over financial reporting and has determined the Company s internal control over financial reporting was effective as of December 31, 2007.

The effectiveness of the Company s internal control over financial reporting as of December 31, 2007, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Aubrey K. McClendon

Chairman and Chief Executive Officer

Marcus C. Rowland

Executive Vice President and Chief Financial Officer

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the accompanying consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Chesapeake Energy Corporation and its subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control Over Financial Reporting appearing in Item 8. Our responsibility is to express opinions on these financial statements and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

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

PricewaterhouseCoopers LLP

Tulsa, Oklahoma

February 29, 2008

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
	($ in millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 1	$ 3
Accounts receivable	1,074	845
Short-term derivative instruments	203	225
Deferred income taxes	1	
Inventory	87	58
Other	30	23
Total Current Assets	1,396	1,154
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, at cost based on full-cost accounting:		
Evaluated oil and natural gas properties	27,656	21,949
Unevaluated properties	5,641	3,797
Less: accumulated depreciation, depletion and amortization of oil and natural gas properties	(7,112)	(5,292)
Total oil and natural gas properties, at cost based on full-cost accounting	26,185	20,454
Other property and equipment:		
Natural gas gathering systems and treating plants	1,135	552
Buildings and land	816	429
Drilling rigs and equipment	106	301
Natural gas compressors	63	127
Other	327	241
Less: accumulated depreciation and amortization of other property and equipment	(295)	(200)
Total Other Property and Equipment	2,152	1,450
Total Property and Equipment	28,337	21,904
OTHER ASSETS:		
Investments	612	699
Long-term derivative instruments	4	339
Other assets	385	321
Total Other Assets	1,001	1,359
TOTAL ASSETS	$ 30,734	$ 24,417

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (Continued)

LIABILITIES AND STOCKHOLDERS EQUITY	December 31, 2007	2006
	($ in millions)	
CURRENT LIABILITIES:		
Accounts payable	$ 1,262	$ 860
Short-term derivative instruments	174	112
Accrued liabilities	717	419
Deferred income taxes		39
Revenues and royalties due others	433	318
Accrued interest	175	142
Total Current Liabilities	2,761	1,890
LONG-TERM LIABILITIES:		
Long-term debt, net	10,950	7,376
Deferred income tax liabilities	3,966	3,317
Asset retirement obligations	236	193
Long-term derivative instruments	408	160
Revenues and royalties due others	42	30
Other liabilities	241	200
Total Long-Term Liabilities	15,843	11,276
CONTINGENCIES AND COMMITMENTS (Note 4)		
STOCKHOLDERS EQUITY:		
Preferred Stock, $.01 par value, 20,000,000 shares authorized:		
4.125% cumulative convertible preferred stock, 3,062 and 3,065 shares issued and outstanding as of December 31, 2007 and 2006, respectively, entitled in liquidation to $3 million	3	3
5.00% cumulative convertible preferred stock (Series 2005), 5,000 shares and 4,600,000 shares issued and outstanding as of December 31, 2007 and 2006, entitled in liquidation to $1 million and $460 million	1	460
4.50% cumulative convertible preferred stock, 3,450,000 shares issued and outstanding as of December 31, 2007 and 2006, entitled in liquidation to $345 million	345	345
5.00% cumulative convertible preferred stock (Series 2005B) 5,750,000 shares issued and outstanding as of December 31, 2007 and 2006, entitled in liquidation to $575 million	575	575
6.25% mandatory convertible preferred stock, 143,768 and 2,300,000 shares issued and outstanding as of December 31, 2007 and 2006, respectively, entitled in liquidation to $36 million and $575 million	36	575
Common Stock, $.01 par value, 750,000,000 shares authorized, 511,648,217 and 458,600,789 shares issued December 31, 2007 and 2006, respectively	5	5
Paid-in capital	7,032	5,873
Retained earnings	4,150	2,913
Accumulated other comprehensive income (loss), net of tax of $6 million and ($319) million, respectively	(11)	528
Less: treasury stock, at cost; 500,821 and 1,167,007 common shares as of December 31, 2007 and 2006, respectively	(6)	(26)
Total Stockholders Equity	12,130	11,251
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 30,734	$ 24,417

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2007	2006	2005
	($ in millions, except per share data)		
REVENUES:			
Oil and natural gas sales	$ 5,624	$ 5,619	$ 3,273
Oil and natural gas marketing sales	2,040	1,577	1,392
Service operations revenue	136	130	
Total Revenues	7,800	7,326	4,665
OPERATING COSTS:			
Production expenses	640	490	317
Production taxes	216	176	208
General and administrative expenses	243	139	64
Oil and natural gas marketing expenses	1,969	1,522	1,358
Service operations expense	94	68	
Oil and natural gas depreciation, depletion and amortization	1,835	1,359	894
Depreciation and amortization of other assets	154	104	51
Employee retirement expense		55	
Total Operating Costs	5,151	3,913	2,892
INCOME FROM OPERATIONS	2,649	3,413	1,773
OTHER INCOME (EXPENSE):			
Interest and other income	15	26	10
Interest expense	(406)	(301)	(220)
Gain on sale of investment	83	117	
Loss on repurchases or exchanges of Chesapeake senior notes			(70)
Total Other Income (Expense)	(308)	(158)	(280)
INCOME BEFORE INCOME TAXES	2,341	3,255	1,493
INCOME TAX EXPENSE:			
Current	29	5	
Deferred	861	1,247	545
Total Income Tax Expense	890	1,252	545
NET INCOME	1,451	2,003	948
PREFERRED STOCK DIVIDENDS	(94)	(89)	(42)
LOSS ON CONVERSION/EXCHANGE OF PREFERRED STOCK	(128)	(10)	(26)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 1,229	$ 1,904	$ 880
EARNINGS PER COMMON SHARE:			
Basic	$ 2.69	$ 4.78	$ 2.73

Assuming dilution	$ 2.62	$ 4.35	$ 2.51
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.2625	$ 0.23	$ 0.195
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):			
Basic	456	398	322
Assuming dilution	487	459	367

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2007	2006	2005
	($ in millions)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME	$ 1,451	$ 2,003	$ 948
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion, and amortization	1,971	1,449	936
Deferred income taxes	835	1,252	545
Unrealized (gains) losses on derivatives	415	(497)	(43)
Amortization of loan costs and bond discount	26	21	15
Realized (gains) losses on financing derivatives	(92)	(136)	
Stock-based compensation	84	84	15
Gain on sale of investments	(83)	(117)	
Income from equity investments `		(10)	
Loss on repurchases or exchanges of Chesapeake senior notes			70
Premiums paid for repurchasing of senior notes			(60)
Other		(4)	
(Increase) decrease in accounts receivable	(192)	(22)	(205)
(Increase) decrease in inventory and other assets	(65)	(126)	(67)
Increase (decrease) in accounts payable, accrued liabilities and other	456	1,020	92
Increase (decrease) in current and non-current revenues and royalties due others	126	(74)	161
Cash provided by operating activities	4,932	4,843	2,407
CASH FLOWS FROM INVESTING ACTIVITIES:			
Acquisitions of oil and natural gas companies, proved and unproved properties, net of cash acquired	(2,961)	(3,960)	(4,135)
Exploration and development of oil and natural gas properties	(5,305)	(3,779)	(2,162)
Additions to other property and equipment	(1,310)	(594)	(417)
Additions to drilling rig equipment	(129)	(393)	(67)
Additions to investments	(8)	(554)	(135)
Acquisition of trucking company, net of cash acquired		(45)	
Proceeds from sale of volumetric production payment	1,089		
Proceeds from sale of investments	124	159	
Proceeds from sale of drilling rigs and equipment	369	244	
Proceeds from sale of compressors	188		
Deposits for acquisitions	(15)	(22)	(35)
Divestitures of oil and natural gas properties			10
Sale of non-oil and natural gas assets	36	2	20
Cash used in investing activities	(7,922)	(8,942)	(6,921)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term borrowings	7,932	8,370	5,682
Payments on long-term borrowings	(6,160)	(8,264)	(5,765)
Proceeds from issuance of senior notes, net of offering costs	1,607	1,755	2,925
Proceeds from issuance of common stock, net of offering costs		1,759	986
Proceeds from issuance of preferred stock, net of offering costs		558	1,341
Cash paid to purchase or exchange Chesapeake senior notes			(566)
Cash paid for common stock dividends	(115)	(87)	(60)
Cash paid for preferred stock dividends	(95)	(88)	(31)
Cash paid for financing cost of credit facilities	(3)	(5)	(5)
Cash paid for treasury stock		(86)	(4)
Derivative settlements	(91)	(87)	(12)

Net increase (decrease) in outstanding payments in excess of cash balance	(98)	70	61
Cash received from exercise of stock options	15	73	21
Excess tax benefit from stock-based compensation	20	88	
Other financing costs	(24)	(14)	(6)
Cash provided by financing activities	2,988	4,042	4,567
Net increase (decrease) in cash and cash equivalents	(2)	(57)	53
Cash and cash equivalents, beginning of period	3	60	7
Cash and cash equivalents, end of period	$ 1	$ 3	$ 60

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

	Years Ended December 31,		
	2007	2006	2005
	($ in millions)		
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:			
Interest, net of capitalized interest	$ 315	$ 273	$ 175
Income taxes, net of refunds received	$ 55	$	$

SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:

As of December 31, 2007, 2006 and 2005, dividends payable on our common and preferred stock were $53 million, $53 million and $38 million, respectively.

In 2007, 2006 and 2005, oil and natural gas properties were adjusted by $131 million, $180 million and $252 million, respectively, for net income tax liabilities related to acquisitions.

During 2007, 2006 and 2005, accrued exploration and development costs of $97 million, $85 million and $27 million, respectively, were recorded as additions to oil and natural gas properties.

We recorded non-cash asset additions to net oil and natural gas properties of $29 million, $23 million and $77 million in 2007, 2006 and 2005, respectively, for asset retirement obligations.

In 2007, holders of our 5.0% (Series 2005) cumulative convertible preferred stock and 6.25% mandatory convertible preferred stock exchanged 4,535,880 shares and 2,156,184 shares for 19,038,891 and 17,367,823 shares of common stock, respectively, in public exchange offers.

In 2007, a holder of our 5.0% (Series 2005) cumulative convertible preferred stock exchanged 59,120 shares into 244,420 shares of common stock in a privately negotiated exchange.

In 2007, holders of our 4.125% cumulative convertible preferred stock and 6.25% mandatory convertible preferred stock converted 3 shares and 48 shares into 180 shares and 344 shares of common stock at a conversion price of $16.643 per share and $34.855 per share, respectively.

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

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

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

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

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

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

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

In 2005, Chesapeake acquired Columbia Energy Resources, LLC and its subsidiaries, including Columbia Natural Resources, LLC (CNR), for a total consideration of $3.02 billion, consisting of $2.2 billion of cash and derivative liabilities, prepaid sales agreements and other liabilities of $0.8 billion.

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	Years Ended December 31, 2007	2006	2005
	($ in millions)		
PREFERRED STOCK:			
Balance, beginning of period	$ 1,958	$ 1,577	$ 491
Issuance of 6.25% mandatory convertible preferred stock		575	
Issuance of 5.00% cumulative convertible preferred stock (Series 2005)			460
Issuance of 4.50% cumulative convertible preferred stock			345
Issuance of 5.00% cumulative convertible preferred stock (Series 2005B)			575
Exchange of common stock for 4,595,000, 0 and 0 shares of 5.00% preferred stock (Series 2005)	(459)		
Exchange of common stock for 2,156,232, 0 and 0 shares of 6.25% preferred stock	(539)		
Exchange of common stock for 3, 85,995 and 224,190 shares of 4.125% preferred stock		(86)	(224)
Exchange of common stock for 0, 1,025,946 and 699,054 shares of 5.00% preferred stock (Series 2003)		(103)	(70)
Exchange of common stock for 0, 99,310 and 3,800 shares of 6.00% preferred stock		(5)	
Balance, end of period	960	1,958	1,577
COMMON STOCK:			
Balance, beginning of period	5	4	3
Issuance of 0, 58,750,000 and 32,200,000 shares of common stock		1	1
Issuance of 0, 1,375,989 and 0 shares of common stock for the purchase of Chaparral Energy, Inc. common stock			
Exchange of 36,651,658, 12,251,870 and 18,703,069 shares of common stock for preferred stock			
Exercise of stock options			
Restricted stock grants			
Balance, end of period	5	5	4
PAID-IN CAPITAL:			
Balance, beginning of period	5,873	3,803	2,440
Issuance of common stock		1,799	1,024
Issuance of common stock for the purchase of Chaparral Energy, Inc. common stock		40	
Exchange of 36,651,658, 12,251,870 and 18,703,069 shares of common stock for preferred stock	998	193	294
Equity-based compensation	129	100	82
Adoption of SFAS 123(R)		(89)	
Offering expenses		(58)	(77)
Exercise of stock options	15	73	22
Release of 0, 6,500,000 and 0 shares from treasury stock upon exercise of stock options		(75)	
Tax benefit from exercise of stock options and restricted stock	20	88	18
Preferred stock conversion/exchange expenses	(3)	(1)	
Balance, end of period	7,032	5,873	3,803
RETAINED EARNINGS (DEFICIT):			
Balance, beginning of period	2,913	1,101	263
Net income	1,451	2,003	948
Dividends on common stock	(121)	(96)	(65)
Dividends on preferred stock	(89)	(95)	(46)
Adoption of FIN48	(4)		

Balance, end of period	4,150	2,913	1,100
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance, beginning of period	528	(195)	20
Hedging activity	(520)	809	(266)
Marketable securities activity	(19)	(86)	51
Balance, end of period	(11)	528	(195)
UNEARNED COMPENSATION:			
Balance, beginning of period		(89)	(32)
Restricted stock granted			(80)
Amortization of unearned compensation			23
Adoption of SFAS 123(R)		89	
Balance, end of period			(89)
TREASURY STOCK COMMON:			
Balance, beginning of period	(26)	(26)	(22)
Purchase of 0, 2,707,471 and 257,220 shares of treasury stock		(86)	(4)
Release of 0, 6,500,000 and 0 shares upon exercise of stock options		75	
Release of 666,186, 361,280 and 8,525 shares for company benefit plans	20	11	
Balance, end of period	(6)	(26)	(26)
TOTAL STOCKHOLDERS EQUITY	$ 12,130	$ 11,251	$ 6,174

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2007	**2006**	**2005**
		($ in millions)	
Net Income	$ 1,451	$ 2,003	$ 948
Other comprehensive income (loss), net of income tax:			
Change in fair value of derivative instruments, net of income taxes of ($56) million, $1.033 billion and ($318) million, respectively	(92)	1,711	(553)
Reclassification of (gain) loss on settled contracts, net of income taxes of ($308) million, ($426) million and $137 million, respectively	(504)	(706)	238
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of $46 million, ($116) million and $28 million, respectively	76	(195)	49
Unrealized gain on marketable securities, net of income taxes of ($11) million, ($8) million and $29 million, respectively	(19)	(13)	51
Reclassification of gain on sales of investments, net of income taxes of $0, ($46) million and $0, respectively		(73)	
Comprehensive income	$ 912	$ 2,727	$ 733

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Summary of Significant Accounting Policies

Description of Company

Chesapeake Energy Corporation (Chesapeake or the company) is an oil and natural gas exploration and production company engaged in the exploration, development and acquisition of properties for the production of crude oil and natural gas from underground reservoirs, and we provide marketing and midstream services for natural gas and oil for other working interest owners in properties we operate. Our properties are located in Oklahoma, Texas, Alabama, Arkansas, Louisiana, Kansas, Montana, Colorado, North Dakota, Nebraska, New Mexico, West Virginia, Kentucky, Ohio, New York, Maryland, Michigan, Mississippi, Pennsylvania, Tennessee, Utah, Virginia and Wyoming.

Principles of Consolidation

The accompanying consolidated financial statements of Chesapeake include the accounts of our direct and indirect wholly owned subsidiaries. All significant intercompany accounts and transactions have been eliminated.

Accounting Estimates

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

Cash Equivalents

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

Accounts Receivable

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

Accounts receivable consists of the following components:

	December 31,	
	2007	2006
	($ in millions)	
Oil and natural gas sales	$ 798	$ 618
Joint interest	175	135
Service operations	10	17
Related parties	18	12
Other	81	68
Allowance for doubtful accounts	(8)	(5)
Total accounts receivable	$ 1,074	$ 845

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Inventory

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

Oil and Natural Gas Properties

Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities (see Note 11). Capitalized costs are amortized on a composite unit-of-production method based on proved oil and natural gas reserves. As of December 31, 2007, approximately 79% of our proved reserves were evaluated by independent petroleum engineers, with the balance evaluated by our internal reservoir engineers. In addition, our internal engineers review and update our reserves on a quarterly basis. The average composite rates used for depreciation, depletion and amortization were $2.57 per mcfe in 2007, $2.35 per mcfe in 2006 and $1.91 per mcfe in 2005.

Proceeds from the sale of properties are accounted for as reductions of capitalized costs unless such sales involve a significant change in the relationship between costs and the value of proved reserves or the underlying value of unproved properties, in which case a gain or loss is recognized.

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

We review the carrying value of our oil and natural gas properties under the full-cost accounting rules of the Securities and Exchange Commission on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In calculating future net revenues, current prices and costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. Our qualifying cash flow hedges as of December 31, 2007, which consisted of swaps and collars, covered 358 bcfe, 82 bcfe and 10 bcfe in 2008, 2009 and 2010, respectively. Our oil and natural gas hedging activities are discussed in Note 10 of these consolidated financial statements.

Two primary factors impacting the ceiling test are reserve levels and current prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of natural gas and oil reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense. Under SEC regulations, the excess above the ceiling is not expensed (or is reduced) if, subsequent to the end of the period, but prior to the release of the financial statements, oil and natural gas prices increase sufficiently such that an excess above the ceiling would have been eliminated (or reduced) if the increased prices were used in the calculations.

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We account for seismic costs in accordance with Rule 4-10 of Regulation S-X. Specifically, Rule 4-10 requires that all companies that use the full-cost method capitalize exploration costs as part of their oil and natural gas properties (i.e., full-cost pool). Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Further, exploration costs include, among other things, geological and geophysical studies and salaries and other expenses of geologists, geophysical crews and others conducting those studies. Such costs are capitalized as incurred. Seismic costs directly associated with the acquisition and evaluation of unproved properties are excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the properties. The company reviews its unproved properties and associated seismic costs quarterly in order to ascertain whether impairment has incurred. To the extent that seismic costs cannot be directly associated with specific unevaluated properties, they are included in the amortization base as incurred.

Other Property and Equipment

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

	December 31		
	2007	2006	Useful Life
	($ in millions)		(in years)
Natural gas gathering systems and treating plants	$ 1,135	$ 552	20
Buildings and improvements	421	305	15 39
Drilling rigs and equipment	106	301	15
Other fixtures and equipment	327	241	2 7
Natural gas compressors	63	127	15
Land	395	124	
Total	$ 2,447	$ 1,650	

Investments

Investments in securities are accounted for under the equity method in circumstances where we are deemed to exercise significant influence over the operating and investing policies of the investee but do not have control. Under the equity method, we recognize our share of the investee s earnings in our consolidated statements of operations. Investments in securities not accounted for under the equity method are accounted for under the cost method. Investments in marketable equity securities accounted for under the cost method have been designated as available for sale and, as such, are recorded at fair value.

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At December 31, 2007, investments accounted for under the equity method totaled $563 million and investments accounted for under the cost method totaled $49 million. Following is a summary of our investments:

			December 31,	
			2007	2006
	Approximate % Owned	Accounting Method	Carrying Value	Carrying Value
			($ in millions)	
Chaparral Energy, Inc.	32%	Equity	$ 271	$ 280
Frac Tech Services, Ltd	20%	Equity	237	254
Gastar Exploration Ltd (a)	17%	Cost	42	69
Eagle Energy Partners I, L.P.	33%	Equity		36
DHS Drilling Company	48%	Equity	28	26
Mountain Drilling Company	49%	Equity	19	24
Other			15	10
			$ 612	$ 699

(a) Our investment in Gastar had an associated cost basis of $89 million and $86 million as of December 31, 2007 and 2006, respectively.
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.

In August 2006, we invested $254 million to acquire a 19.9% interest in Frac Tech Services, Ltd., a privately-held provider of well stimulation and high pressure pumping services, with operations focused in Texas (principally in the Barnett Shale) and the Rocky Mountains. The carrying value of our investment in Frac Tech is in excess of our underlying equity in net assets by approximately $181 million as of December 31, 2007. This excess amount is attributed to certain intangibles associated with the specialty services provided by Frac Tech and is being amortized over the estimated life of the intangibles.

In September 2006, we acquired 32% of the outstanding common stock of Chaparral Energy, Inc. for $240 million in cash and 1,375,989 newly issued shares of our common stock valued at $40 million. Chaparral is a privately-held independent oil and natural gas company headquartered in Oklahoma City, Oklahoma. The carrying value of our investment in Chaparral is in excess of our underlying equity in net assets by approximately $216 million as of December 31, 2007. This excess amount is attributed to the oil and natural gas reserves held by Chaparral and is amortized over the estimated life of these reserves based on a unit of production rate.

In 2006, we sold our investment in publicly-traded Pioneer Drilling Company common stock, realizing proceeds of $159 million and a gain of $117 million. We owned 17% of the common stock of Pioneer, which we began acquiring in 2003.

Capitalized Interest

During 2007, 2006 and 2005, interest of approximately $269 million, $179 million and $79 million, respectively, was capitalized on significant investments in unproved properties that were not being currently depreciated, depleted or amortized and on which exploration activities were in progress. Interest is capitalized using a weighted average interest rate based on our outstanding borrowings.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Accounts Payable and Accrued Liabilities

Included in accounts payable at December 31, 2007 and 2006, respectively, are liabilities of approximately $150 million and $248 million representing the amount by which checks issued, but not yet presented to our banks for collection, exceeded balances in applicable bank accounts. Other accrued liabilities include $262 million and $177 million of accrued drilling costs as of December 31, 2007 and 2006, respectively.

Debt Issue Costs

Included in other assets are costs associated with the issuance of our senior notes and costs associated with our revolving bank credit facility and hedging facilities. The remaining unamortized debt issue costs at December 31, 2007 and 2006 totaled $138 million and $116 million, respectively, and are being amortized over the life of the senior notes, revolving credit facility or hedging facilities.

Asset Retirement Obligations

Chesapeake follows Statement of Financial Accounting Standards (SFAS) No. 143, *Accounting for Asset Retirement Obligations.* This statement applies to obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets.

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

Revenue Recognition

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

Natural Gas Imbalances. We follow the sales method of accounting for our natural gas revenue whereby we recognize sales revenue on all natural gas sold to our purchasers, regardless of whether the sales are proportionate to our ownership in the property. An asset or a liability is recognized to the extent that we have an imbalance in excess of the remaining natural gas reserves on the underlying properties. The natural gas imbalance net position at December 31, 2007 and 2006 was a liability of $4 million and $5 million, respectively.

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

Hedging

From time to time, Chesapeake uses commodity price and financial risk management instruments to mitigate our exposure to price fluctuations in oil and natural gas and interest rates. Recognized gains and losses on derivative contracts are reported as a component of the related transaction. Results of oil and natural gas derivative transactions are reflected in oil and natural gas sales and results of interest rate hedging transactions

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

are reflected in interest expense. The changes in fair value of derivative instruments not qualifying for designation as either cash flow or fair value hedges that occur prior to maturity are reported currently in the consolidated statement of operations as unrealized gains (losses) within oil and natural gas sales or interest expense.

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

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

Stock-Based Compensation

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

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Prior to the adoption of SFAS 123(R), we followed the intrinsic value method in accordance with APB 25 to account for employee stock-based compensation. Prior period financial statements have not been restated. Upon adoption of SFAS 123(R), we eliminated $89 million of unearned compensation cost and reduced additional paid-in capital by the same amount on our consolidated balance sheet.

For the years ended December 31, 2007, 2006 and 2005, we recorded the following stock-based compensation ($ in millions):

	2007	2006	2005
Production expenses	$ 19	$ 7	$
General and administrative expenses	57	27	15
Service operations expense	3		
Oil and natural gas marketing expenses	5		
Oil and natural gas properties	68	23	12
Employee retirement expense		51	
Total	$ 152	$ 108	$ 27

SFAS 123(R) generally did not change the accounting for awards of restricted stock. The impact to income before income taxes of adopting SFAS 123(R) for 2006 was a reduction of $3 million associated with stock option awards. SFAS 123(R) also requires cash inflows resulting from tax deductions in excess of compensation expense recognized for stock options and restricted stock (excess tax benefits) to be classified as financing cash inflows in our statements of cash flows. Accordingly, for the years ended December 31, 2007 and 2006, we reported $20 million and $88 million, respectively, of excess tax benefits from stock-based compensation as cash provided by financing activities on our statements of cash flows.

Pro forma Disclosures

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

	Year Ended December 31, 2005
Net Income:	
As reported	$ 948
Add: Stock-based compensation expense included in reported net income, net of income tax	10
Deduct: Total stock-based compensation expense determined under fair value based method for all awards, net of income tax	(18)
Pro forma net income	$ 940
Basic earnings per common share:	
As reported	$ 2.73
Pro forma	$ 2.71

Diluted earnings per common share:		
As reported	$	2.51
Pro forma	$	2.48

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for 2006 and 2005 to conform to the presentation used for the 2007 consolidated financial statements.

2. Net Income Per Share

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

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

For the year ended December 31, 2007, diluted shares do not include the common stock equivalent of our 5.00% (Series 2005) convertible preferred stock outstanding prior to conversion (convertible into 16,158,815 shares) and the preferred stock adjustments to net income do not include $76 million of dividends and loss on conversion/exchange related to these preferred shares, as the effect on diluted earnings per share would have been antidilutive.

For the year ended December 31, 2007, diluted shares do not include the common stock equivalent of our 6.25% mandatory convertible preferred stock outstanding prior to conversion (convertible into 13,982,602 shares) and the preferred stock adjustments to net income do not include $99 million of dividends and loss on conversion/exchange related to these preferred shares, as the effect on diluted earnings per share would have been antidilutive.

For the years ended December 31, 2006 and 2005, diluted shares do not include the common stock equivalent of our 4.125% convertible preferred stock outstanding prior to conversion (convertible into 2,090,292 and 8,610,708 shares, respectively) and the preferred stock adjustments to net income do not include $9 million and $29 million, respectively, of dividends and loss on conversion/exchange related to these preferred shares, as the effect on diluted earnings per share would have been antidilutive.

For the year ended December 31, 2005, outstanding options to purchase 0.1 million shares of common stock at a weighted-average exercise price of $29.85 per share, were antidilutive because the exercise price of the options was greater than the average market price of the common stock.

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A reconciliation for the years ended December 31, 2007, 2006 and 2005 is as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
For the Year Ended December 31, 2007:			
Basic EPS:			
Income available to common shareholders	$ 1,229	456	$ 2.69
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.50% convertible preferred stock		8	
Common shares assumed issued for 5.00% (Series 2005B) convertible preferred stock		15	
Common shares assumed issued for 6.25% mandatory convertible preferred stock		1	
Employee stock options		4	
Restricted stock		3	
Preferred stock dividends	47		
Diluted EPS income available to common shareholders and assumed conversions	$ 1,276	487	$ 2.62
For the Year Ended December 31, 2006:			
Basic EPS:			
Income available to common shareholders	$ 1,904	398	$ 4.78
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.50% convertible preferred stock		8	
Common shares assumed issued for 5.00% (Series 2005) convertible preferred stock		18	
Common shares assumed issued for 5.00% (Series 2005B) convertible preferred stock		15	
Common shares assumed issued for 6.25% mandatory convertible preferred stock		9	
Assumed conversion as of the beginning of the period of preferred shares outstanding prior to conversion:			
Common stock equivalent of preferred stock outstanding prior to conversion, 5.00% (Series 2003) convertible preferred stock		2	
Employee stock options		6	
Restricted stock		3	
Loss on redemption of preferred stock	3		
Preferred stock dividends	87		
Diluted EPS income available to common shareholders and assumed conversions	$ 1,994	459	$ 4.35
For the Year Ended December 31, 2005:			
Basic EPS:			
Income available to common shareholders	$ 880	322	$ 2.73

Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.125% convertible preferred stock		5	
Common shares assumed issued for 4.50% convertible preferred stock		2	
Common shares assumed issued for 5.00% (Series 2003) convertible preferred stock		6	
Common shares assumed issued for 5.00% (Series 2005) convertible preferred stock		13	
Common shares assumed issued for 5.00% (Series 2005B) convertible preferred stock		2	
Common shares assumed issued for 6.00% convertible preferred stock		1	
Assumed conversion as of the beginning of the period of preferred shares outstanding prior to conversion:			
Common stock equivalent of preferred stock outstanding prior to conversion, 5.00% (Series 2003) convertible preferred stock		3	
Employee stock options		11	
Restricted stock		2	
Loss on redemption of preferred stock	3		
Preferred stock dividends	36		
Diluted EPS income available to common shareholders and assumed conversions	$ 919	367	$ 2.51

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. Senior Notes and Revolving Bank Credit Facility

Our long-term debt consisted of the following at December 31, 2007 and 2006:

	December 31, 2007	December 31, 2006
	($ in millions)	
7.5% Senior Notes due 2013	$ 364	$ 364
7.625% Senior Notes due 2013	500	500
7.0% Senior Notes due 2014	300	300
7.5% Senior Notes due 2014	300	300
7.75% Senior Notes due 2015	300	300
6.375% Senior Notes due 2015	600	600
6.625% Senior Notes due 2016	600	600
6.875% Senior Notes due 2016	670	670
6.5% Senior Notes due 2017	1,100	1,100
6.25% Euro-denominated Senior Notes due 2017 (a)	876	792
6.25% Senior Notes due 2018	600	600
6.875% Senior Notes due 2020	500	500
2.75% Contingent Convertible Senior Notes due 2035 (b)	690	690
2.5% Contingent Convertible Senior Notes due 2037 (b)	1,650	
Revolving bank credit facility	1,950	178
Discount on senior notes	(105)	(101)
Impact of interest rate derivatives (c)	55	(17)
Total notes payable and long-term debt	$ 10,950	$ 7,376

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.4603 to 1.00 and $1.3197 to 1.00 as of December 31, 2007 and 2006, respectively. See Note 10 for information on our related cross currency swap.

(b) The holders of our Contingent Convertible Senior Notes may require us to repurchase all or a portion of their notes 5, 10, 15 or 20 years prior to the maturity date, or upon a fundamental change, at 100% of the principal amount of the notes, payable in cash. The notes are convertible, at the holder s option, prior to maturity under certain circumstances, into cash and, if applicable, shares of our common stock using a net share settlement process. In general, upon conversion of a convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note s conversion value in excess of such principal amount. In addition, we will pay contingent interest on the convertible senior notes, beginning with the six-month interest period ending May 14, 2016 with respect to the 2.75% Contingent Convertible Senior Notes due 2035 and November 14, 2017 with respect to the 2.5% Contingent Convertible Senior Notes due 2037, under certain conditions. We may redeem the convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash.

(c) See Note 10 for further discussion related to these instruments.

No scheduled principal payments are required under our senior notes until 2013 when $864 million is due.

In 2005, we repurchased or exchanged $564 million of Chesapeake debt in order to re-finance a portion of our long-term debt at a lower rate of interest and recognized a loss of $70 million. No such purchases or exchanges were completed in 2007 or 2006.

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Our outstanding senior notes are unsecured senior obligations of Chesapeake that rank equally in right of payment with all of our existing and future senior indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. We may redeem the senior notes, other than the 2.75% Contingent Convertible Senior Notes due 2035 and the 2.5% Contingent Convertible Senior Notes due 2037, at any time at specified make-whole or redemption prices. Senior notes issued before July 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; incur liens; enter into sale/leaseback transactions; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. Senior notes issued after June 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur certain secured indebtedness; enter into sale/leaseback transactions; and consolidate, merge or transfer assets.

Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under our outstanding senior notes have been fully and unconditionally guaranteed, jointly and severally, by all of our wholly-owned subsidiaries, other than minor subsidiaries, on a senior unsecured basis.

On November 2, 2007, we amended and restated our syndicated revolving bank credit facility to increase the borrowing base to $3.5 billion (with commitments of $3.0 billion) and extended the maturity to November 2012. We subsequently increased the commitments under the credit facility to $3.5 billion. As of December 31, 2007, we had $1.950 billion in outstanding borrowings under our facility and utilized approximately $5 million of the facility for various letters of credit. Borrowings under our facility are secured by certain producing oil and natural gas properties and bear interest at our option of either (i) the greater of the reference rate of Union Bank of California, N.A. or the federal funds effective rate plus 0.50% or (ii) the London Interbank Offered Rate (LIBOR), plus a margin that varies from 0.75% to 1.50% per annum according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are determined periodically. The unused portion of the facility is subject to a commitment fee that also varies according to our senior unsecured long-term debt ratings, from 0.125% to 0.30% per annum. Currently, the commitment fee rate is 0.20% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.70 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.75 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.48 to 1 and our indebtedness to EBITDA ratio was 2.16 to 1 at December 31, 2007. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $75 million.

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Contingencies and Commitments

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

On January 27, 2007, the Circuit Court jury returned a verdict against the defendants of $404 million, consisting of $134 million in compensatory damages and $270 million in punitive damages. Most of the damages awarded by the jury relate to issues not yet addressed by the West Virginia Supreme Court of Appeals, although in June 2006 that Court ruled against the defendants on two certified questions regarding the deductibility of post-production expenses. The jury found 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 effect on the company.

Employment Agreements with Officers. Chesapeake has employment agreements with its chief executive officer, chief operating officer, chief financial officer and other executive officers, which provide for annual base salaries, various benefits and eligibility for bonus compensation. The agreement with the chief executive officer has a term of five years commencing January 1, 2008. The term of the agreement is automatically extended for one additional year on each December 31 unless the company provides 30 days notice of non-extension. In the event of termination of employment without cause, the chief executive officer s base compensation (defined as base salary plus bonus compensation received during the preceding 12 months) and benefits would continue during the remaining term of the agreement. The chief executive officer is entitled to receive a payment in the amount of three times his base compensation upon the happening of certain events following a change of control. The agreement further provides that any stock-based awards held by the chief executive officer and deferred compensation will immediately become 100% vested upon termination of employment without cause, incapacity, death or retirement at or after age 55, and any unexercised stock options will not terminate as the result of

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

termination of employment. The agreements with the chief operating officer, chief financial officer and other executive officers expire on September 30, 2009. These agreements provide for the continuation of salary for one year in the event of termination of employment without cause or death and, in the event of a change of control, a payment in the amount of two times the executive officer s base compensation. These executive officers are entitled to continue to receive compensation and benefits for 180 days following termination of employment as a result of incapacity. Any stock-based awards held by such executive officers will immediately become 100% vested upon termination of employment without cause, a change of control, death or retirement at or after age 55.

Environmental Risk. Due to the nature of the oil and natural gas business, Chesapeake and its subsidiaries are exposed to possible environmental risks. Chesapeake has implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. Chesapeake conducts periodic reviews, on a company-wide basis, to identify changes in our environmental risk profile. These reviews evaluate whether there is a contingent liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. Depending on the extent of an identified environmental problem, Chesapeake may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property. Chesapeake has historically not experienced any significant environmental liability, and is not aware of any potential material environmental issues or claims at December 31, 2007.

Rig Leases. In a series of transactions in 2006 and 2007, our drilling subsidiaries sold 78 drilling rigs and related equipment for $613 million and entered into a master lease agreement under which we agreed to lease the rigs from the buyer for initial terms of seven to ten years for rental payments of approximately $87 million annually. The lease obligations are guaranteed by Chesapeake and its other material subsidiaries. These transactions were recorded as sales and operating leasebacks and any related gain or loss is being amortized to service operations expense over the lease term. Under the rig leases, we have the option to purchase the rigs starting in 2013 or on the expiration of the lease term for a purchase price equal to the then fair market value of the rigs. Additionally, we have the option to renew the rig lease for a negotiated renewal term at a periodic rental equal to the fair market rental value of the rigs as determined at the time of renewal.

Compressor Leases. In a series of transactions in 2007, our wholly-owned subsidiary, MidCon Compression, L.L.C., sold a significant portion of its compressor fleet, consisting of 1,199 compressors, for $188 million and entered into a master lease agreement. The term of the agreement varies by buyer ranging from seven to ten years for aggregate rental payments of approximately $23 million annually. MidCon s lease obligations are guaranteed by Chesapeake and its other material subsidiaries. These transactions were recorded as sales and operating leasebacks and any related gain or loss is being amortized to oil and natural gas marketing expense over the lease term. Under the leases, we can exercise an early purchase option after six to nine years or we can purchase the compressors at expiration of the lease for the fair market value at the time. In addition, we have the option to renew the lease for negotiated new terms at the expiration of the lease. 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Commitments related to rig, compressor and other operating lease payments are not recorded in the accompanying consolidated balance sheets. As of December 31, 2007, minimum future lease payments were as follows ($ in millions):

	Rigs	Compressors	Other	Total
2008	$ 87	$ 27	$ 8	$ 122
2009	87	22	6	115
2010	87	21	3	111
2011	87	21	2	110
2012	88	23	2	113
After 2012	192	94	1	287
Total	$ 628	$ 208	$ 22	$ 858

Rent expense, including short-term rentals, for the years ended December 31, 2007, 2006 and 2005 was $81 million, $47 million and $30 million, respectively.

Transportation Contracts. Chesapeake has various firm pipeline transportation service agreements with expiration dates ranging from one to 93 years. These commitments are not recorded in the accompanying consolidated balance sheets. Under the terms of these contracts, we are obligated to pay demand charges as set forth in the transporter s Federal Energy Regulatory Commission (FERC) gas tariff. In exchange, the company receives rights to flow natural gas production through pipelines located in highly competitive markets. Excluded from this summary are demand charges for pipeline projects that are currently seeking regulatory approval. The aggregate amounts of such required demand payments as of December 31, 2007 are as follows ($ in millions):

2008	$ 69
2009	67
2010	63
2011	59
2012	53
After 2012	224
Total	$ 535

Drilling Contracts. We have contracts with various drilling contractors to use 32 drilling rigs in 2008 with terms of one to three years. These commitments are not recorded in the accompanying consolidated balance sheets. Minimum future commitments as of December 31, 2007 are as follows ($ in millions):

2008	$ 144
2009	57
2010	11
After 2010	

Total	$ 212

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Gas Purchase Obligations. Our marketing segment regularly purchases gas from other owners in our oil and gas properties and, accordingly, has commitments to purchase gas which typically are short term in nature. We have also committed to purchase gas associated with the December 31, 2007 sale of a volumetric production payment. The purchase commitment extends over a 15 year term at market prices at the time of production, and the purchased gas will be resold. The obligations are as follows:

	Mmcfe
2008	19,858
2009	18,601
2010	18,043
2011	16,251
2012	15,322
After 2012	119,949
Total	208,024

Other. Chesapeake and a leading investment bank have an agreement to lend Mountain Drilling Company, of which Chesapeake is a 49% equity owner, up to $32 million each through December 31, 2009. At December 31, 2007, Mountain Drilling owed Chesapeake $21 million under this agreement.

Chesapeake has an agreement to lend Ventura Refining and Transmission LLC, of which Chesapeake is a 25% equity owner, up to $31 million through January 31, 2017. At December 31, 2007, there was $26 million outstanding under this agreement. Additionally, we have agreed to guarantee various commitments for Ventura, up to $70 million, to support their operating activities. As of December 31, 2007, we had guaranteed $61 million of commitments.

5. Income Taxes

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

	Years Ended December 31,		
	2007	2006	2005
	($ in millions)		
Current	$ 29	$ 5	$
Deferred	861	1,247	545
Total	$ 890	$ 1,252	$ 545

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

	Years Ended December 31,

	2007	2006	2005
		($ in millions)	
Computed expected federal income tax provision	$ 819	$ 1,139	$ 523
State income taxes	56	90	23
Other	15	23	(1)
	$ 890	$ 1,252	$ 545

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Years Ended December 31, 2007	2006
	($ in millions)	
Deferred tax liabilities:		
Oil and natural gas properties	$ (3,760)	$ (3,259)
Other property and equipment	(152)	(106)
Derivative instruments	(20)	(398)
Volumetric production payment	(442)	
Deferred tax liabilities	(4,374)	(3,763)
Deferred tax assets:		
Net operating loss carryforwards	$ 170	$ 290
Asset retirement obligation	91	74
Investments	33	7
Accrued liabilities	6	4
Percentage depletion carryforwards	11	6
Alternative minimum tax credits	61	6
Other	37	20
Deferred tax assets	409	407
Total deferred tax asset (liability)	$ (3,965)(a)	$ (3,356)
Reflected in accompanying balance sheets as:		
Current deferred income tax asset	$ 1	$
Current deferred income tax liability		(39)
Non-current deferred income tax liability	(3,966)	(3,317)
	$ (3,965)	$ (3,356)

(a) In addition to the income tax expense of $890 million, activity during 2007 includes a net liability of $131 million related to acquisitions and deferred tax assets for $314 million related to derivative instruments, $11 million related to investments, $20 million related to stock-based compensation, $56 million related to AMT payments and $3 million related to the implementation of FIN 48. In addition, the activity includes a reduction to deferred tax liabilities of $8 million related to state income tax payments and other miscellaneous items. These items were not recorded as part of the provision for income taxes.

As of December 31, 2007, we classified $1 million of deferred tax assets as current that were attributable to the current portion of derivative liabilities and other current temporary differences. As of December 31, 2006, we classified $39 million of deferred tax liabilities as current that were attributable to the current portion of derivative assets and other current temporary differences.

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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. Additionally, we had $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 these carryforwards depends on the ability of Chesapeake to generate taxable income. In addition, for AMT purposes, only 90% of AMT income in any given year may be offset by AMT NOLs. A summary of our NOLs follows:

	NOL	AMT NOL
	($ in millions)	
Expiration Date:		
December 31, 2019	$ 17	$
December 31, 2020	1	
December 31, 2021	17	
December 31, 2022	36	
December 31, 2023	126	2
December 31, 2024	5	1
December 31, 2025	22	
December 31, 2026	14	2
Total	$ 238	$ 5

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

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

The following table summarizes our net operating losses as of December 31, 2007 and any related limitations:

	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.

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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 was 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.

A reconciliation of the beginning and ending balances of unrecognized tax benefits is as follows:

	($ in millions)
Balance at January 1, 2007	$ 142
Additions based on tax positions related to the current year	64
Reductions for tax positions of prior years	(52)
Settlements	(21)
Balance at December 31, 2007	$ 133

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 2003 and 2004 U.S. income tax returns in September 2007. This examination resulted in an additional AMT liability of $9 million. This AMT liability can be utilized as a credit 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.

6. Related Party Transactions

As of December 31, 2007, we had accrued accounts receivable from our CEO, Aubrey K. McClendon, of $18 million representing joint interest billings from December 2007 which were invoiced and timely paid in January 2008. Since Chesapeake was founded in 1989, Mr. McClendon has acquired working interests in virtually all of our oil and natural gas properties by participating in our drilling activities under the terms of the Founder Well Participation Program (FWPP) described below. Joint interest billings to him are settled in cash immediately upon delivery of a monthly joint interest billing.

Under the FWPP, approved by our shareholders in June 2005, Mr. McClendon (and our co-founder and former COO, Tom L. Ward, prior to August 10, 2006) may elect to participate in all or none of the wells drilled by or on behalf of Chesapeake during a calendar year, but he is not allowed to participate only in selected wells.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A participation election is required to be received by the Compensation Committee of Chesapeake s Board of Directors not less than 30 days prior to the start of each calendar year. His participation is permitted only under the terms outlined in the Founder Well Participation Program, which, among other things, limits his individual participation to a maximum working interest of 2.5% in a well and prohibits participation in situations where Chesapeake s working interest would be reduced below 12.5% as a result of his participation. In addition, the company is reimbursed for costs associated with leasehold acquired by Mr. McClendon as a result of his well participation. Mr. Ward s participation in the Founder Well Participation Program terminated on August 10, 2006.

As disclosed in Note 8, in 2007, 2006 and 2005 Chesapeake had revenues of $1.1 billion, $867 million and $851 million, respectively, from oil and natural gas sales to Eagle Energy Partners I, L.P., a former affiliated entity. We sold our 33% limited partnership interest in Eagle Energy in June 2007.

7. Employee Benefit Plans

Our qualified 401(k) profit sharing plan is the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan, which is open to employees of Chesapeake and all our subsidiaries except certain employees of Chesapeake Appalachia, L.L.C. On January 1, 2007, a plan we maintained for the employees of our subsidiary Nomac Drilling Corporation was merged into the Chesapeake plan. Eligible employees may elect to defer compensation through voluntary contributions to their 401(k) plan accounts, subject to plan limits and those set by the Internal Revenue Service. Chesapeake matches employee contributions dollar for dollar (subject to a maximum contribution of 15% of the employees annual compensation) with Chesapeake common stock purchased in the open market. For the Nomac plan, the matching percentage was 8% for 2005 through June 2006, and 15% as of July 1, 2006. The company contributed $28 million, $18 million and $10 million to the Chesapeake plan in 2007, 2006 and 2005, respectively, and $2 million and a nominal amount to the Nomac plan in 2006 and 2005, respectively.

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

Prior to 2008, we maintained two nonqualified deferred compensation plans, the 401(k) make-up plan and the deferred compensation plan. Effective on January 1, 2008, the deferred compensation plans were merged into the Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan. To be eligible to participate in the amended and restated deferred compensation plan an employee must receive annual compensation (base salary and bonus combined) of at least $100,000, have a minimum of one year of service as a company employee and have made the maximum contribution allowable under the 401(k) plan. For employees with at least five years of service as a company employee, the company matches employee contributions to the plan in Chesapeake common stock. Chesapeake matches 100% of employee contributions up to 15% of base salary and bonus in the aggregate for the 401(k) plan and the amended and restated deferred compensation plan. We contributed $4 million, $2 million and $2 million to the 401(k) make-up plan during 2007, 2006 and 2005, respectively. The company s non-employee directors are able to defer up to 100% of director fees into the amended and restated deferred compensation plan.

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Employees with at least one year of service receiving an annual base salary of at least $100,000 ($95,000 in 2005) during the 12 months prior to the enrollment date were eligible to participate in our deferred compensation plan. In addition, non-employee directors were able to defer up to 100% of director fees into the plan. The maximum compensation that can be deferred by employees under all company deferred compensation plans, including the Chesapeake 401(k) plan, was a total of 75% of base salary and 100% of performance bonus. Chesapeake made no matching or other contributions to the deferred compensation plan.

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

Chesapeake maintains no post-employment benefit plans except those sponsored by Chesapeake Appalachia, L.L.C. As of December 31, 2006, a total of 188 employees were eligible for these plans. As of January 1, 2007, participation in these plans was limited to union members (135 employees) and continuing eligibility is the subject of ongoing labor negotiations. The Chesapeake Appalachia, L.L.C. benefit plans provide health care and life insurance benefits to eligible employees upon retirement. We account for these benefits on an accrual basis. As of December 31, 2007, the company had accrued $2 million in accumulated post-employment benefit liability.

8. Major Customers and Segment Information

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

Year Ended December 31,	Customer	Amount ($ in millions)	Percent of Total Revenues
2007	Eagle Energy Partners I, L.P.	$ 1,072	15%
2006	Eagle Energy Partners I, L.P.	$ 867	16%
2005	Eagle Energy Partners I, L.P.	$ 851	18%

In September 2003, Chesapeake invested approximately $6 million in Eagle Energy Partners I, L.P. and received a 25% limited partnership interest. Through additional investments totaling $27 million, Chesapeake increased its limited partner ownership interest to $33 million or approximately 33% as of December 31, 2006. In 2007, we sold our 33% limited partnership interest for proceeds of $124 million and a gain of $83 million.

In accordance with Statement of Financial Accounting Standards No. 131, *Disclosures about Segments of an Enterprise and Related Information*, we have two reportable operating segments. Our exploration and production operational segment and oil and natural gas marketing segment are managed separately because of the nature of their products and services. The exploration and production segment is responsible for finding and producing oil and natural gas. The marketing segment is responsible for gathering, processing, compressing, transporting and selling oil and natural gas primarily from Chesapeake-operated wells. We also have drilling rig and trucking operations which are responsible for providing drilling rigs primarily used on Chesapeake-operated wells and trucking services utilized in the transportation of drilling rigs on both Chesapeake-operated wells and wells operated by third parties.

Management evaluates the performance of our segments based upon income before income taxes. Revenues from the marketing segment s sale of oil and natural gas related to Chesapeake s ownership interests are reflected as exploration and production revenues. Such amounts totaled $3.5 billion, $2.6 billion and $2.4 billion for 2007,

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2006 and 2005, respectively. The following tables present selected financial information for Chesapeake s operating segments. Our drilling and trucking service operations are presented in Other Operations for all periods presented.

For the Year Ended December 31, 2007:	**Exploration and Production**	**Marketing**	**Other Operations** ($ in millions)	**Intercompany Eliminations**	**Consolidated Total**
Revenues	$ 5,624	$ 5,508	$ 493	$ (3,825)	$ 7,800
Intersegment revenues		(3,468)	(357)	3,825	
Total Revenues	5,624	2,040	136		7,800
Depreciation, depletion and amortization	1,954	25	26	(16)	1,989
Interest and other income	14	1			15
Interest expense	406				406
Other income/expense	83				83
INCOME BEFORE INCOME TAXES	$ 2,287	$ 41	$ 135	$ (122)	$ 2,341
TOTAL ASSETS	$ 29,317	$ 1,759	$ 487	$ (829)	$ 30,734
CAPITAL EXPENDITURES	$ 7,977	$ 534	$ (163)	$	$ 8,348
For the Year Ended December 31, 2006:					
Revenues	$ 5,619	$ 4,135	$ 325	$ (2,753)	$ 7,326
Intersegment revenues		(2,558)	(195)	2,753	
Total Revenues	5,619	1,577	130		7,326
Depreciation, depletion and amortization	1441	10	28	(16)	1,463
Interest and other income	22	4			26
Interest expense	300		1		301
Other income/expense	117				117
INCOME BEFORE INCOME TAXES	$ 3,192	$ 41	$ 106	$ (84)	$ 3,255
TOTAL ASSETS	$ 23,333	$ 864	$ 786	$ (566)	$ 24,417
CAPITAL EXPENDITURES	$ 8,423	$ 255	$ 231	$	$ 8,909
For the Year Ended December 31, 2005:					
Revenues	$ 3,273	$ 3,788	$ 61	$ (2,457)	$ 4,665
Intersegment revenues		(2,396)	(61)	2,457	
Total Revenues	3,273	1,392			4,665
Depreciation, depletion and amortization	940	5	6	(6)	945
Interest and other income	9	1			10
Interest expense	220				220
Other income/expense	70				70
INCOME BEFORE INCOME TAXES	$ 1,467	$ 26	$ 10	$ (10)	$ 1,493
TOTAL ASSETS	$ 15,124	$ 688	$ 306	$	$ 16,118
CAPITAL EXPENDITURES	$ 7,696	$ 133	$ 70	$	$ 7,899

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9. Stockholders Equity, Restricted Stock and Stock Options

The following is a summary of the changes in our common shares outstanding for 2007, 2006 and 2005:

	2007	2006	2005
		(in thousands)	
Shares issued at January 1	458,601	375,511	316,941
Stock option and warrant exercises	2,127	6,969	3,996
Restricted stock issuances (net of forfeitures)	14,268	3,743	3,671
Preferred stock conversions/exchanges	36,652	12,252	18,703
Common stock issuances for cash		58,750	32,200
Common stock issued for the purchase of Chaparral Energy, Inc. common stock		1,376	
Shares issued at December 31	511,648	458,601	375,511

The following is a summary of the changes in our preferred shares outstanding for 2007, 2006 and 2005:

	6.00%	5.00% (2003)	4.125%	5.00% (2005)	4.50%	5.00% (2005B)	6.25%
				(in thousands)			
Shares outstanding at January 1, 2007			3	4,600	3,450	5,750	2,300
Preferred stock issuances							
Conversion/exchange of preferred for common stock				(4,595)			(2,156)
Shares outstanding at December 31, 2007			3	5	3,450	5,750	144
Shares outstanding at January 1, 2006	99	1,026	89	4,600	3,450	5,750	
Preferred stock issuances							2,300
Conversion/exchange of preferred for common stock	(99)	(1,026)	(86)				
Shares outstanding at December 31, 2006			3	4,600	3,450	5,750	2,300
Shares outstanding at January 1, 2005	103	1,725	313				
Preferred stock issuances				4,600	3,450	5,750	
Conversion/exchange of preferred for common stock	(4)	(699)	(224)				
Shares outstanding at December 31, 2005	99	1,026	89	4,600	3,450	5,750	

In 2007, shares of our preferred stock were exchanged for or converted into common stock as follows:

3 shares of 4.125% cumulative convertible preferred stock were converted 180 shares of common stock pursuant to conversion rights;

59,120 shares of 5.0% (Series 2005) cumulative convertible preferred stock were exchanged for 244,420 shares of common stock in a privately negotiated exchange transaction;

4,535,880 shares of 5.0% (Series 2005) cumulative convertible preferred stock were exchanged for 19,038,891 shares of common stock pursuant to our tender offer for the shares;

48 shares of 6.25% mandatory convertible preferred stock were converted into 344 shares of common stock pursuant to the holder s conversion rights; and

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

- 2,156,184 shares of 6.25% mandatory convertible preferred stock were exchanged for 17,367,823 shares of common stock pursuant to our tender offer for the shares.

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

- 221,898 shares of 5.0% (Series 2003) cumulative convertible preferred stock were exchanged for or converted into 1,375,670 shares of common stock in privately negotiated exchange transactions or pursuant to conversion rights;
- 804,048 shares of 5.0% (Series 2003) cumulative convertible preferred stock were exchanged for 4,972,786 shares of common stock pursuant to our tender offer for the shares;
- 2,750 shares of 4.125% cumulative convertible preferred stock were exchanged for 172,594 shares of common stock in privately negotiated exchange transactions;
- 83,245 shares of 4.125% cumulative convertible preferred stock were exchanged for 5,248,126 shares of common stock pursuant to our tender offer for the shares; and
- the remaining 99,310 shares of 6.0% cumulative convertible preferred stock were exchanged for or converted into 482,694 shares of common stock in privately negotiated exchange transactions or pursuant to conversion rights.

In 2005, shares of our preferred stock were exchanged for or converted into common stock as follows:

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

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Dividends on our outstanding preferred stock are payable quarterly in cash or, with respect to our 6.25% mandatory convertible preferred stock and our 4.50% cumulative convertible preferred stock, we may pay dividends in cash, common stock or a combination thereof. Following is a summary of our preferred stock, including the primary conversion terms as of December 31, 2007:

Preferred Stock Series	Issue Date	Liquidation Preference per Share	Holder s Conversion Right	Conversion Rate	Conversion Price	Company s Conversion Right From	Company s Market Conversion Trigger
6.25% Mandatory Convertible (a)	June/July 2006	$ 250	Any time	7.1725	$ 34.8551	Any time	$ 52.2827(b)
5.00% (Series 2005) Cumulative Convertible	April 2005	$ 100	Any time	3.8864	$ 25.7308	April 15, 2010	$ 33.4503(c)
4.50% Cumulative Convertible	September 2005	$ 100	Any time	2.2640	$ 44.1690	September 15, 2010	$ 57.4197(c)
5.00% (Series 2005B) Cumulative Convertible	November 2005	$ 100	Any time	2.5599	$ 39.0645	November 15, 2010	$ 50.7839(c)
4.125% Cumulative Convertible	March/April 2004	$ 1,000	Market price >$ 21.62	60.1374	$ 16.6286	March 15, 2009	$ 21.6200(c)

(a) Each share converts automatically on June 15, 2009 into 7.1725 to 8.6071 shares of common stock, depending on the common stock market price at the time.

(b) Convertible at initial conversion rate plus cash equal to present value of future dividends to June 15, 2009.

(c) Convertible at the company s option if the company s common stock equals or exceeds the trigger price for a specified time period.

Stock-Based Compensation Plans

Under Chesapeake s Long Term Incentive Plan, restricted stock, stock options, stock appreciation rights, performance shares and other stock awards may be awarded to employees, directors and consultants of Chesapeake. Subject to any adjustments as provided by the plan, the aggregate number of shares of common stock available for awards under the plan may not exceed 17,000,000 shares. The maximum period for exercise of an option or stock appreciation right may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the option or stock appreciation right on the date of grant. Awards granted under the plan become vested at dates or upon the satisfaction of certain performance or other criteria determined by a committee of the Board of Directors. No awards may be granted under this plan after September 30, 2014. This plan has been approved by our shareholders. Stock options to purchase 150,000 shares of our common stock were issued to our directors from this plan in 2005. In addition, 87,500, 75,000 and 62,500 shares of restricted stock were issued to our directors from this plan in 2007, 2006 and 2005, respectively. There were 14.7 million and 2,610 restricted shares issued, net of forfeitures to employees and consultants during 2007 and 2006, respectively from this plan. As of December 31, 2007, there were 2,010,000 shares remaining available for issuance under the plan.

Under Chesapeake s 2003 Stock Incentive Plan, restricted stock and incentive and nonqualified stock options to purchase our common stock may be awarded to employees and consultants of Chesapeake. Subject to any adjustments as provided by the plan, the aggregate number of shares available for awards under the plan may not exceed 10,000,000 shares. The maximum period for exercise of an option may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the option on the date of grant. Restricted stock and options granted become vested at dates determined by a committee of the Board of Directors. No awards may be granted under this plan after April 14, 2013. This plan

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has been approved by our shareholders. There were 0.2 million, 4.0 million and 3.9 million restricted shares, net of forfeitures, issued during 2007, 2006 and 2005, respectively, from this plan. As of December 31, 2007, there were 450,562 shares remaining available for issuance under the plan.

Under Chesapeake s 2003 Stock Award Plan for Non-Employee Directors, 10,000 shares of Chesapeake s common stock are awarded to each newly appointed non-employee director on his or her first day of service. Subject to any adjustments as provided by the plan, the aggregate number of shares which may be issued may not exceed 100,000 shares. This plan has been approved by our shareholders. In each of 2007, 2006 and 2005, 10,000 shares of common stock were awarded to new directors from this plan. As of December 31, 2007, there were 60,000 shares remaining available for issuance under this plan.

Under Chesapeake s 2002 Non-Employee Director Stock Option Plan and 1992 Nonstatutory Stock Option Plan, we granted nonqualified options to purchase our common stock to members of our Board of Directors who are not Chesapeake employees. Subject to any adjustments provided for in the plans, the 2002 plan and the 1992 plan covered a maximum of 500,000 shares and 3,132,000 shares, respectively. The 1992 plan terminated in December 2002 and the 2002 plan terminated in June 2005. Pursuant to a formula award provision in the plans, each non-employee director received a quarterly grant of a ten-year immediately exercisable option to purchase shares of common stock at an exercise price equal to the fair market value of the shares on the date of grant. Both plans were approved by our shareholders.

In addition to the plans described above, we have stock options outstanding to employees under a number of employee stock option plans which are described below. All outstanding options under these plans were at-the-money when granted, with an exercise price equal to the closing price of our common stock on the date of grant and have a ten-year exercise period. These plans were terminated in June 2005 (with the exception of the 1994 plan which expired in October 2004) and therefore no shares remain available for stock option grants under the plans.

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

Restricted Stock

Chesapeake began issuing shares of restricted common stock to employees in January 2004 and to non-employee directors in July 2005. The fair value of the awards issued is determined based on the fair market value of the shares on the date of grant. This value is amortized over the vesting period, which is generally four years from the date of grant for employees and three years for non-employee directors. To the extent amortization of compensation cost relates to employees directly involved in acquisition, exploration and development activities, such amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized in general and administrative expense or production expense. Note 1

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details the accounting for our stock-based compensation expense in 2007, 2006 and 2005. As of December 31, 2005, the unamortized balance of unearned compensation recorded as a reduction of stockholders equity was $89 million. Upon adoption of SFAS 123(R) in January 2006, we eliminated the unamortized balance of unearned compensation in stockholders equity ($89 million) and reduced additional paid-in capital by the same amount on our consolidated balance sheet.

A summary of the status of the unvested shares of restricted stock and changes during 2007, 2006 and 2005 is presented below:

	Number of Unvested Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2007	7,074,761	$ 25.85
Granted	15,560,570	34.25
Vested	(2,255,384)	24.34
Forfeited	(691,188)	33.29
Unvested shares as of December 31, 2007	19,688,759	$ 32.42
Unvested shares as of January 1, 2006	5,805,210	$ 18.38
Granted	4,392,270	31.77
Vested	(2,818,249)	19.78
Forfeited	(304,470)	25.04
Unvested shares as of December 31, 2006	7,074,761	$ 25.85
Unvested shares as of January 1, 2005	2,684,850	$ 14.35
Granted	3,940,405	20.41
Vested	(739,255)	14.71
Forfeited	(80,790)	17.09
Unvested shares as of December 31, 2005	5,805,210	$ 18.38

The aggregate intrinsic value of restricted stock vested during 2007 was approximately $73 million.

As of December 31, 2007, there was $565 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of 3.11 years.

The vesting of certain restricted stock grants results in state and federal income tax benefits related to the difference between the market price of the common stock at the date of vesting and the date of grant. During the years ended December 31, 2007, 2006 and 2005, we recognized excess tax benefits related to restricted stock of $5 million, $4 million and $2 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

Our President and Chief Operating Officer, Tom L. Ward, resigned as a director, officer and employee of the company effective February 10, 2006. Mr. Ward s Resignation Agreement provided for the immediate vesting of all of his unvested equity awards, which consisted of options to purchase 724,615 shares of Chesapeake s common stock at an average exercise price of $8.01 per share and 1,291,875 shares of restricted common stock. As a result of this vesting, we incurred an expense of $55 million in 2006.

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Stock Options

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

The following table provides information related to stock option activity for 2007, 2006 and 2005:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value (a) ($ in millions)
Outstanding at January 1, 2007	6,605,703	$ 7.43		
Exercised	(2,146,640)	7.16		$ 61
Forfeited/ Canceled	(13,608)	9.90		
Outstanding at December 31, 2007	4,445,455	$ 7.55	4.37	$ 141
Exercisable at December 31, 2007	4,422,519	$ 7.51	4.36	$ 140
Shares authorized for future grants	2,460,562			
Fair value of options granted during period	$			
Outstanding at January 1, 2006	20,256,013	$ 6.14		
Exercised	(13,494,835)	5.34		$ 352
Forfeited/ Canceled	(155,475)	20.22		
Outstanding at December 31, 2006	6,605,703	$ 7.43	5.36	$ 143
Exercisable at December 31, 2006	5,337,153	$ 7.02	5.14	$ 118
Shares authorized for future grants	6,719,642			
Fair value of options granted during period	$			
Outstanding at January 1, 2005	24,228,464	$ 6.00		
Granted	177,500	18.67		
Exercised	(4,032,180)	5.78		
Forfeited/ Canceled	(117,771)	8.51		
Outstanding at December 31, 2005	20,256,013	$ 6.14		
Exercisable at December 31, 2005	15,960,440	$ 5.57		

Shares authorized for future grants		6,452,444
Fair value of options granted during period	$	6.21

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

As of December 31, 2007, unrecognized compensation cost related to unvested stock options was not significant.

During the years ended December 31, 2007, 2006 and 2005, we recognized excess tax benefits related to stock options of $15 million, $84 million and $16 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

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The following table summarizes information about stock options outstanding at December 31, 2007:

Range of Exercise Prices		Outstanding Options Number Outstanding	Weighted-Avg. Remaining Contractual Life	Weighted-Avg. Exercise Price	Options Exercisable Number Exercisable	Weighted-Avg. Exercise Price
$ 0.94	$ 4.00	458,063	1.75	$ 2.65	458,063	$ 2.65
5.20	5.20	502,623	4.56	5.20	502,623	5.20
5.35	5.89	313,277	2.98	5.57	313,277	5.57
6.11	6.11	942,023	3.76	6.11	942,023	6.11
6.40	7.74	172,377	3.75	6.92	172,377	6.92
7.80	7.80	663,684	5.01	7.80	663,684	7.80
7.86	10.01	184,331	4.75	8.51	184,331	8.51
10.08	10.08	738,818	5.47	10.08	738,818	10.08
10.10	16.08	414,009	6.22	13.48	391,073	13.44
22.49	22.49	56,250	7.25	22.49	56,250	22.49
$ 0.94	$22.49	4,445,455	4.37	$ 7.55	4,422,519	$ 7.51

Shareholder Rights Plan

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

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

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

10. Financial Instruments and Hedging Activities

Oil and Natural Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of December 31, 2007, our oil and natural gas derivative instruments were comprised of swaps, basis protection swaps, knockout swaps, cap-swaps, call options and collars. These instruments allow us to predict with greater certainty the effective oil and natural gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

For swap instruments, Chesapeake receives a fixed price for the hedged commodity and pays a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

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Basis protection swaps are arrangements that guarantee a price differential for oil or natural gas from a specified delivery point. For Mid-Continent basis protection swaps, which have negative differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. For Appalachian Basin basis protection swaps, which have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.

For knockout swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty s exposure to zero, in any given month, if the floating market price is lower than certain pre-determined knockout prices.

For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a cap limiting the counterparty s exposure. In other words, there is no limit to Chesapeake s exposure but there is a limit to the downside exposure of the counterparty.

For call options, Chesapeake receives a premium from the counterparty in exchange for the sale of a call option. If the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess. If the market price settles below the fixed price of the call option, no payment is due from Chesapeake.

Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.

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

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

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

Gains or losses from certain derivative transactions are reflected as adjustments to oil and natural gas sales on the consolidated statements of operations. Realized gains (losses) are included in oil and natural gas sales in the month of related production. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within oil and natural gas sales. Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and natural gas sales as unrealized gains (losses). The components of oil and natural gas sales for the years ended December 31, 2007, 2006 and 2005 are presented below.

	Years Ended December 31,		
	2007	2006	2005
	($ in millions)		
Oil and natural gas sales	$ 4,795	$ 3,870	$ 3,633
Realized gains on oil and natural gas derivatives	1,203	1,254	(401)
Unrealized gains (losses) on non-qualifying oil and natural gas derivatives	(252)	184	117
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(122)	311	(76)
Total oil and natural gas sales	$ 5,624	$ 5,619	$ 3,273

The estimated fair values of our oil and natural gas derivative instruments as of December 31, 2007 and 2006 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	December 31, 2007	December 31, 2006
	($ in millions)	
Derivative assets (liabilities):		
Fixed-price natural gas swaps	$ (54)	$ 1
Natural gas basis protection swaps	151	187
Fixed-price natural gas knockout swaps	108	122
Fixed-price natural gas counter-swaps		(5)
Natural gas call options (a)	(230)	(5)
Fixed-price natural gas collars (b)	4	(7)
Fixed-price oil swaps	(110)	28
Fixed-price oil cap-swaps	(17)	24
Fixed-price oil knockout swaps	(125)	
Oil call options (c)	(96)	
Estimated fair value	$ (369)	$ 345

(a) After adjusting for $255 million and $15 million of unrealized premiums, the cumulative unrealized gain (loss) related to these call options as of December 31, 2007 and 2006 was $25 million and $10 million, respectively.

(b) After adjusting for $8 million of unrealized discount, the cumulative unrealized loss related to these collars as of December 31, 2007 was $4 million.

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(c) After adjusting for $29 million of unrealized premiums, the cumulative unrealized loss related to these call options as of December 31, 2007 was ($67) million.

In 2006 and 2007, Chesapeake lifted or assigned a portion of its 2008 through 2022 hedges and as a result has approximately $215 million of deferred hedging gains as of December 31, 2007. These gains have been recorded in accumulated other comprehensive income or as an unrealized gain in oil and natural gas sales. For amounts originally recorded in other comprehensive income, the gain will be recognized in oil and natural gas sales in the month of the hedged production.

Based upon the market prices at December 31, 2007, we expect to transfer approximately $127 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to earnings during the next 12 months in the related month of production. All transactions hedged as of December 31, 2007 are expected to mature by December 31, 2022.

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

	Secured Hedging Facilities (a)					
	#1	#2	#3	#4	#5	#6
	($ in millions)					
Maximum permitted value of transactions under facility	$ 750	$ 500	$ 500	$ 250	$ 500	$ 500
Per annum exposure fee	1%	1%	1%	0.8%	0.8%	0.8%
Scheduled maturity date	2010	2010	2011	2012	2012	2012
Fair value of outstanding transactions, as of December 31, 2007	$ 1	$ (144)	$ (97)	$ (19)	$ (37)	$ (53)

(a) Chesapeake Exploration, L.L.C. is the named party to the facilities numbered 1-3 and Chesapeake Energy Corporation is the named party to the facilities numbered 4-6.

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

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the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes at market prices on the date of our acquisition of CNR.

Pursuant to Statement of Financial Accounting Standards No. 149, *Amendment of SFAS 133 on Derivative Instruments and Hedging Activities*, the derivative instruments assumed in connection with the CNR acquisition are deemed to contain a significant financing element, and all cash flows associated with these positions are reported as financing activity in the statement of cash flows for the periods in which settlement occurs. The aggregate fair value of the remaining CNR derivatives as of December 31, 2007 was a liability of $184 million.

Interest Rate Derivatives

We use interest rate derivatives to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value are recorded on the consolidated balance sheets as assets (liabilities), and the debt s carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

Gains or losses from derivative transactions are reflected as adjustments to interest expense on the consolidated statements of operations. Realized gains (losses) included in interest expense were ($1) million, ($2) million and $5 million in 2007, 2006 and 2005, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as fair value hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within interest expense. Unrealized gains (losses) included in interest expense were ($40) million, $2 million and $2 million in 2007, 2006 and 2005, respectively.

As of December 31, 2007, the following interest rate derivatives were outstanding:

	Notional Amount ($ in millions)	Weighted Average Fixed Rate	Weighted Average Floating Rate	Weighted Average Cap/ Floor Rate	Fair Value Hedge	Net Premiums ($ in millions)	Fair Value ($ in millions)
Fixed to Floating Swaps:							
July 2005 January 2018	$ 1,500	6.750%	6 month LIBOR plus 164 basis points		Yes	$	$ 28
September 2004 July 2013	$ 325	7.942%	6 month LIBOR plus 297 basis points		No		9
Floating to Fixed Swaps:							
August 2007 July 2010	$ 750	4.803%	3 month LIBOR		No		(14)
Call Options:							
August 2007 February 2008	$ 750	6.875%			No	6	(32)
Collars:							
August 2007 August 2010	$ 1,075			5.37% 4.32%	No		(20)
						$ 6	$ (29)

In 2007, we sold call options on six of our interest rate swaps and received $11 million in premiums. Two of the options expired unexercised in 2007.

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In 2007, we closed ten interest rate swaps for gains totaling $18 million. These interest rate swaps were designated as fair value hedges, and the settlement amounts received will be amortized as a reduction to realized interest expense over the remaining term of the related senior notes.

Foreign Currency Derivatives

On December 6, 2006, we issued 600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties will pay Chesapeake 19 million and Chesapeake will pay the counterparties $30 million, which will yield an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake 600 million and Chesapeake will pay the counterparties $800 million. The terms of the cross currency swap were based on the dollar/euro exchange rate on the issuance date of $1.3325 to 1.00. Through the cross currency swap, we have eliminated any potential variability in Chesapeake s expected cash flows related to changes in foreign exchange rates and therefore the swap qualifies as a cash flow hedge under SFAS 133. The euro-denominated debt is recorded in notes payable ($876 million at December 31, 2007) using an exchange rate of $1.4603 to 1.00. The fair value of the cross currency swap is recorded on the consolidated balance sheet as an asset of $23 million at December 31, 2007. The translation adjustment to notes payable is completely offset by the fair value of the cross currency swap and therefore there is no impact to the consolidated statement of operations. The remaining value of the cross currency swap related to future interest payments is reported in other comprehensive income.

Fair Value of Financial Instruments

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

The carrying values of financial instruments comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term fixed-rate debt and our convertible preferred stock using primarily quoted market prices. Our carrying amounts for such debt, excluding the impact of interest rate derivatives, at December 31, 2007 and 2006 were $8.9 billion and $7.2 billion, respectively, compared to approximate fair values of $9.2 billion and $7.3 billion, respectively. The carrying amounts for our convertible preferred stock as of December 31, 2007 and 2006 were $960 million and $2.0 billion, respectively, compared to approximate fair values of $1.0 billion and $1.9 billion, respectively.

Concentration of Credit Risk

A significant portion of our liquidity is concentrated in derivative instruments that enable us to hedge a portion of our exposure to price volatility from producing oil and natural gas. These arrangements expose us to credit risk from our counterparties. Other financial instruments which potentially subject us to concentrations of credit risk consist principally of investments in equity instruments and accounts receivable. Our accounts receivable are primarily from purchasers of oil and natural gas products and exploration and production companies which own interests in properties we operate. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected

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by changes in economic, industry or other conditions. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

11. Supplemental Disclosures About Oil And Natural Gas Producing Activities

Net Capitalized Costs

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

	December 31, 2007	December 31, 2006
	($ in millions)	
Oil and natural gas properties:		
Proved	$ 27,656	$ 21,949
Unproved	5,641	3,797
Total	33,297	25,746
Less accumulated depreciation, depletion and amortization	(7,112)	(5,292)
Net capitalized costs	$ 26,185	$ 20,454

Unproved properties not subject to amortization at December 31, 2007, 2006 and 2005 consisted mainly of leasehold acquired through corporate and significant oil and natural gas property acquisitions and through direct purchases of leasehold. We capitalized approximately $269 million, $179 million and $79 million of interest during 2007, 2006 and 2005, respectively, on significant investments in unproved properties that were not yet included in the amortization base of the full-cost pool. We will continue to evaluate our unevaluated properties; however, the timing of the ultimate evaluation and disposition of the properties has not been determined.

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

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

	December 31,		
	2007	2006	2005
		($ in millions)	
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
Total	$ 8,694	$ 8,126	$ 7,416

(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.

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

Chesapeake s results of operations from oil and natural gas producing activities are presented below for 2007, 2006 and 2005. The following table includes revenues and expenses associated directly with our oil and natural gas producing activities. It does not include any interest costs or general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our oil and natural gas operations.

	Years Ended December 31,		
	2007	2006	2005
		($ in millions)	
Oil and natural gas sales (a)	$ 5,624	$ 5,619	$ 3,273
Production expenses	(640)	(490)	(317)
Production taxesf	(216)	(176)	(208)
Depletion and depreciation	(1,835)	(1,359)	(894)

Imputed income tax provision (b)	(1,115)	(1,383)	(677)
Results of operations from oil and natural gas producing activities	$ 1,818	$ 2,211	$ 1,177

(a) Includes ($374) million, $495 million and $41 million of unrealized gains (losses) on oil and natural gas derivatives for the years ended December 31, 2007, 2006 and 2005, respectively.

(b) The imputed income tax provision is hypothetical (at the effective income tax rate) and determined without regard to our deduction for general and administrative expenses, interest costs and other income tax credits and deductions, nor whether the hypothetical tax provision will be payable.

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Oil and Natural Gas Reserve Quantities (unaudited)

Independent petroleum engineers and Chesapeake s petroleum engineers have evaluated our proved reserves. The portion of the proved reserves (by volume) evaluated by each for 2007, 2006 and 2005 is presented below.

	Years Ended December 31,		
	2007	2006	2005
Netherland, Sewell & Associates, Inc.	34%	32%	25%
Data and Consulting Services, Division of Schlumberger Technology Corporation	12	16	16
Lee Keeling and Associates, Inc.	11	14	15
Ryder Scott Company L.P.	11	10	12
LaRoche Petroleum Consultants, Ltd.	11	8	8
H.J. Gruy and Associates, Inc.			2
Internal petroleum engineers	21	20	22
	100%	100%	100%

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

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

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

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Presented below is a summary of changes in estimated reserves of Chesapeake for 2007, 2006 and 2005:

	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)
December 31, 2007			
Proved reserves, beginning of period	106,030	8,319,434	8,955,614
Extensions, discoveries and other additions	11,644	1,053,123	1,122,986
Revisions of previous estimates	7,732	1,298,802	1,345,195
Production	(9,882)	(654,969)	(714,261)
Sale of reserves-in-place		(208,141)	(208,141)
Purchase of reserves-in-place	8,030	329,050	377,230
Proved reserves, end of period	123,554	10,137,299	10,878,623
Proved developed reserves:			
Beginning of period	76,705	5,113,211	5,573,441
End of period	88,834	6,408,622	6,941,626
December 31, 2006			
Proved reserves, beginning of period	103,323	6,900,754	7,520,690
Extensions, discoveries and other additions	8,456	777,858	828,594
Revisions of previous estimates	(3,822)	539,606	516,676
Production	(8,654)	(526,459)	(578,383)
Sale of reserves-in-place	(3)	(123)	(141)
Purchase of reserves-in-place	6,730	627,798	668,178
Proved reserves, end of period	106,030	8,319,434	8,955,614
Proved developed reserves:			
Beginning of period	76,238	4,442,270	4,899,694
End of period	76,705	5,113,211	5,573,441
December 31, 2005			
Proved reserves, beginning of period	87,960	4,373,989	4,901,751
Extensions, discoveries and other additions	12,460	930,800	1,005,563
Revisions of previous estimates	(2,123)	53,950	41,204
Production	(7,698)	(422,389)	(468,577)
Sale of reserves-in-place	(26)	(332)	(486)
Purchase of reserves-in-place	12,750	1,964,736	2,041,235
Proved reserves, end of period	103,323	6,900,754	7,520,690

Proved developed reserves:			
Beginning of period	62,713	2,842,141	3,218,418
End of period	76,238	4,442,270	4,899,694

During 2007, Chesapeake acquired approximately 377 bcfe of proved reserves through purchases of oil and natural gas properties for consideration of $671 million (primarily in 10 separate transactions of greater than $10 million each). In December 2007, we sold 208 bcfe of our proved reserves and production in certain Chesapeake-operated producing assets in Kentucky and West Virginia for approximately $1.1 billion. During 2007, we recorded positive revisions of 1.345 tcfe to the December 31, 2006 estimates of our reserves. Included in the

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revisions were 97 bcfe of positive adjustments caused by higher natural gas prices at December 31, 2007, and 1.248 tcfe of positive performance related revisions of which 1.207 tcfe relate to infill drilling and increased density locations. Higher prices extend the economic lives of the underlying oil and natural gas properties and thereby increase the estimated future reserves. The weighted average oil and natural gas wellhead prices used in computing our reserves were $90.58 per bbl and $6.19 per mcf at December 31, 2007.

During 2006, Chesapeake acquired approximately 668 bcfe of proved reserves through purchases of oil and natural gas properties for consideration of $1.176 billion (primarily in 15 separate transactions of greater than $10 million each). During 2006, we recorded upward revisions of 517 bcfe to the December 31, 2005 estimates of our reserves. Included in the revisions were 212 bcfe of downward adjustments caused by lower natural gas prices at December 31, 2006, offset by 729 bcfe of positive performance related revisions of which 710 bcfe relate to infill drilling and increased density locations. Lower prices reduce the economic lives of the underlying oil and natural gas properties and thereby decrease the estimated future reserves. The weighted average oil and natural gas wellhead prices used in computing our reserves were $56.25 per bbl and $5.41 per mcf at December 31, 2006.

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

Standardized Measure of Discounted Future Net Cash Flows (unaudited)

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

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

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

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

	Years Ended December 31,		
	2007	2006	2005
	($ in millions)		
Future cash inflows	$ 73,955(a)	$ 50,984(b)	$ 66,287(c)
Future production costs	(19,319)	(13,790)	(14,795)
Future development costs	(8,315)	(6,804)	(4,676)
Future income tax provisions	(14,056)	(8,877)	(14,856)
Future net cash flows	32,265	21,513	31,960
Less effect of a 10% discount factor	(17,303)	(11,506)	(15,992)
Standardized measure of discounted future net cash flows	$ 14,962	$ 10,007	$ 15,968

(a) Calculated using weighted average prices of $90.58 per barrel of oil and $6.19 per mcf of natural gas.
(b) Calculated using weighted average prices of $56.25 per barrel of oil and $5.41 per mcf of natural gas.
(c) Calculated using weighted average prices of $56.41 per barrel of oil and $8.76 per mcf of natural gas

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

	Years Ended December 31,		
	2007	2006	2005
	($ in millions)		
Standardized measure, beginning of period (a)	$ 10,007	$ 15,968	$ 7,646
Sales of oil and natural gas produced, net of production costs (b)	(3,939)	(3,204)	(3,108)
Net changes in prices and production costs	3,277	(10,954)	3,249
Extensions and discoveries, net of production and development costs	2,424	1,184	3,145
Changes in future development costs	(639)	(743)	(151)
Development costs incurred during the period that reduced future development costs	1,410	954	491
Revisions of previous quantity estimates	2,960	948	123
Purchase of reserves-in-place	1,166	1,135	6,252
Sales of reserves-in-place	(708)		(1)
Accretion of discount	1,365	2,293	1,050
Net change in income taxes	(1,970)	3,325	(4,107)
Changes in production rates and other	(391)	(899)	1,379
Standardized measure, end of period (a)	$ 14,962	$ 10,007	$ 15,968

(a) The discounted amounts related to cash flow hedges that would affect future net cash flows have not been included in any of the periods presented.
(b) Excluding gains (losses) on derivatives.

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12. Asset Retirement Obligations

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

	Years Ended December 31, 2007	2006
	($ in millions)	
Asset retirement obligations, beginning of period	$ 193	$ 157
Additions	19	22
Revisions (a)	10	3
Settlements and disposals	(1)	(1)
Accretion expense	15	12
Asset retirement obligations, end of period	$ 236	$ 193