CHESAPEAKE ENERGY CORP
Form 10-K
March 14, 2006
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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, 2005

¨ 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
7.0% 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
6.25% Senior Notes due 2018	New York Stock Exchange
6.0% Cumulative Convertible Preferred Stock	New York Stock Exchange
5.0% Cumulative Convertible Preferred Stock (Series 2003)	New York Stock Exchange
4.5% Cumulative 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 ¨

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

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2005 was $6,327,096,262. At March 10, 2006, there were 373,622,333 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2006 Annual Meeting of Shareholders are incorporated by reference in Part III.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

2005 ANNUAL REPORT ON FORM 10-K

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PART I

ITEM 1. *Business*

General

We are the second largest independent producer of natural gas in the United States, owning interests in approximately 30,600 producing oil and gas wells that are currently producing approximately 1.5 bcfe per day, 92% of which is natural gas. Our strategy is focused on discovering, developing and acquiring onshore natural gas reserves primarily in the southwestern U.S. and secondarily in the Appalachian Basin of the eastern U.S. Our most important operating area has historically been the Mid-Continent region of the U.S., which includes Oklahoma, Arkansas, Kansas and the Texas Panhandle, and is where 51% of our proved oil and natural gas reserves are located. During the past four years, we have also built significant positions in the South Texas and Texas Gulf Coast regions, the Permian Basin of West Texas and eastern New Mexico, the Barnett Shale area of north-central Texas, the Ark-La-Tex area of East Texas and northern Louisiana and most recently, the emerging Fayetteville Shale play located in Arkansas. As a result of our recent acquisition of the holding company of Columbia Natural Resources, LLC and certain affiliated entities (CNR), we now have a significant presence in the Appalachian Basin, principally in West Virginia, eastern Kentucky, eastern Ohio and southern New York.

As of December 31, 2005, we had 7.5 tcfe of proved reserves, of which 92% are natural gas and all of which are onshore. During 2005, we replaced our 469 bcfe of production with an internally estimated 3.088 tcfe of new proved reserves, for a reserve replacement rate of 659%. Reserve replacement through the drillbit was 1.047 tcfe, or 223% of production (including a positive 17 bcfe from performance revisions and a positive 24 bcfe from oil and natural gas price increases), and reserve replacement through acquisitions was 2.041 tcfe, or 436% of production. Our proved reserves grew by 53% during 2005, from 4.9 tcfe to 7.5 tcfe.

During 2005, we led the nation in drilling activity with an average utilization of 73 operated rigs and 66 non-operated rigs. Through this drilling activity, we drilled 902 (686 net) operated wells and participated in another 1,066 (130 net) wells operated by other companies. We added approximately 1.047 tcfe of proved oil and natural gas reserves through our drilling efforts. Our success rate was 98% for operated wells and 95% for non-operated wells. As of December 31, 2005, our proved developed reserves were 65% of our total proved reserves. In 2005, we added approximately 1,200 new employees and invested $362 million in leasehold (exclusive of leases acquired through acquisitions) and 3-D seismic data, all of which we consider the building blocks of future value creation.

From January 1, 1998 through December 31, 2005, we have been one of the most active consolidators of onshore U.S. natural gas assets, having purchased approximately 5.9 tcfe of proved reserves, at a total cost of approximately $10.3 billion (including $2.2 billion for unproved leasehold, but excluding $809 million of deferred taxes established in connection with certain corporate acquisitions) for a per proved mcfe acquisition cost of $1.37.

During 2005, we were especially active in the acquisitions market. Acquisition expenditures totaled $4.9 billion through December 31, 2005 (including $1.4 billion for unproved leasehold, but excluding $252 million of deferred taxes established in connection with certain corporate acquisitions). Through these acquisitions, we have acquired an internally estimated 2.0 tcfe of proved oil and natural gas reserves at a per proved mcfe acquisition cost of $1.74.

On November 14, 2005, we acquired CNR and its significant natural gas reserves, acreage and mid-stream assets for approximately $3.02 billion, of which $2.2 billion was in cash and $0.82 billion was in assumed liabilities related to CNR s prepaid sales agreement, hedging positions and other liabilities. The CNR assets consist of 125 mmcfe per day of natural gas production, 1.3 tcfe of proved reserves and approximately 3.2 million net acres of U.S. oil and gas leasehold, which we estimate have over 9,000 additional undrilled locations with reserve potential. CNR also owns extensive mid-stream natural gas assets, including over 6,500 miles of natural gas gathering lines.

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

Recent Developments

In the first quarter of 2006, we have continued to execute our acquisition and financing strategy through the following transactions, in which we:

- acquired oil and natural gas assets from private companies located in the Barnett Shale, South Texas, Permian Basin, Mid-Continent and Ark-La-Tex regions for an aggregate purchase price of approximately $640 million in cash and expect to close another acquisition for a cash purchase price of approximately $60 million by March 31, 2006;
- acquired a privately-held Oklahoma-based trucking company for $48 million;
- issued an additional $500 million of our 6.5% Senior Notes due 2017 in a private placement and used the proceeds of approximately $487 million to repay outstanding borrowings under our revolving bank credit facility incurred primarily to finance our recent acquisitions;
- amended and restated our revolving bank credit facility, increasing the commitments to $2.0 billion and extending the maturity date to February 2011;
- sold our investment in Pioneer Drilling Company (AMEX:PDC) common stock for cash proceeds of $159 million and a pre-tax gain of $116 million; and
- acquired 13 drilling rigs and related assets through our wholly-owned subsidiary, Nomac Drilling Corporation, from Martex Drilling Company, L.L.P., a privately-held drilling contractor with operations in East Texas and North Louisiana, for $150 million.

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 has agreed to act as a consultant to Chesapeake for a period of six months from the effective date of his resignation, pursuant to a resignation agreement, to assist in the transition of his responsibilities. During the term of his consulting agreement, Mr. Ward will receive no cash compensation but will be provided support staff for personal administrative and accounting services together with access to the company s fractional shares in aircraft in accordance with historical practices. The resignation agreement provides for the immediate vesting of all of Mr. Ward s unvested stock options and restricted stock on February 10, 2006. As a result of such vesting, 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 became immediately vested. As a result, the company expects to incur a non-cash after-tax charge of approximately $31.8 million in the first quarter 2006. Mr. Ward will have until May 10, 2006 to exercise the stock options granted to him by the company.

Business Strategy

Since our inception in 1989, our goal has been to create value for investors by building one of the largest onshore natural gas resource bases in the United States. For much of the past eight years, our strategy to accomplish this goal has been to build the dominant operating position in the Mid-Continent region, the third largest gas supply region in the U.S. In building our industry-leading position in the Mid-Continent, we have integrated an aggressive and technologically advanced drilling program with an active property consolidation program focused on small to medium-sized corporate and property acquisitions. In 2002, we began expanding our focus from the Mid-Continent to other regions where we believed we could extend our successful strategy. To date, those areas have included the South Texas and Texas Gulf Coast regions, the Permian Basin of West

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Texas and eastern New Mexico, the Barnett Shale area of north-central Texas, the Ark-La-Tex area of East Texas and northern Louisiana, and, through our recent CNR acquisition, the Appalachian Basin, principally in West Virginia, eastern Kentucky, eastern Ohio and southern New York. We believe significant elements of our successful Mid-Continent strategy of acquisition, exploitation, extension and exploration have been or will be successfully transferred to these areas.

Key elements of this business strategy are further explained below:

Make High-Quality Acquisitions. Our acquisition program is focused on acquisitions of natural gas properties that offer high-quality, long-lived production and significant development and higher potential deep drilling opportunities. From January 1, 1998 through December 31, 2005, we have acquired $10.3 billion of oil and gas properties at an estimated average cost of $1.37 per mcfe of proved reserves. Included in this amount is $2.2 billion for unproved leasehold, but excluded from this amount is $809 million, or $0.14 per mcfe of proved reserves, of deferred taxes established in connection with certain corporate acquisitions. The vast majority of these acquisitions either increased our ownership in existing wells or fields or added additional drilling locations in our focused operating areas. Because these operating areas contain many smaller companies seeking liquidity opportunities and larger companies seeking to divest non-core assets, we expect to continue to find additional attractive acquisition opportunities in the future.

Grow through the Drillbit. One of our most distinctive characteristics is our ability to increase reserves and production through the drillbit. We are currently utilizing 78 operated drilling rigs and 82 non-operated drilling rigs to conduct the most active drilling program in the United States. We focus both on finding significant new natural gas reserves and developing existing proved reserves, principally at deeper depths than the industry average. For the past seven years, we have been aggressively investing in leasehold, 3-D seismic information and human capital to be able to take advantage of the favorable drilling economics that exist today. While we believe U.S. natural gas production has been generally declining during the past five years, we are one of the few large-cap companies that have been able to increase production, which we have successfully achieved for the past 16 consecutive years and 18 consecutive quarters. We believe key elements of the success and scale of our drilling programs have been our early recognition that gas prices were likely to move higher in the U.S. in the post-1999 period accompanied by our willingness to aggressively hire new employees and to build the nation s largest onshore leasehold and 3-D seismic inventories, all of which are the building blocks of value creation in a successful large-scale drilling program.

Build Regional Scale. We believe one of the keys to success in the natural gas exploration industry is to build significant operating scale in a limited number of operating areas that share many similar geological and operational characteristics. Achieving such scale provides many benefits, the most important of which are higher per unit revenues, lower per unit operating costs, greater rates of drilling success, higher returns from more easily integrated acquisitions and higher returns on drilling investments. We first began pursuing this focused strategy in the Mid-Continent in late 1997 and we are now the largest natural gas producer, the most active driller and the most active acquirer of leasehold and producing properties in the Mid-Continent. We believe this region, which trails only the Gulf Coast and Rocky Mountain basins in current U.S. gas production, has many attractive characteristics. These characteristics include long-lived natural gas properties with predictable decline curves; multi-pay geological targets that decrease drilling risk and have resulted in a drilling success rate of 93% over the past sixteen 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 our other operating areas possess many of these same favorable characteristics and our goal is to become or remain a top five producer in each of our operating areas.

Focus on Low Costs. By minimizing lease operating costs and general and administrative expense through focused activities and increased scale, we have been able to deliver attractive financial returns through all phases of the commodity price cycle. We believe our low cost structure is the result of management s effective cost-control programs, a high-quality asset base and the extensive and competitive services, gas processing and transportation infrastructures that exist in our key operating areas. As of December 31, 2005, we operated approximately 18,200 wells, or approximately 80% of our daily production.

Improve our Balance Sheet. We have made significant progress in improving our balance sheet over the past seven years. From December 31, 1998 through December 31, 2005, we have increased our shareholders equity by $6.4 billion through a combination of earnings and common and preferred equity issuances. As of December 31, 2005, our debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders equity) was 47%, compared to 49% as of December 31, 2004 and 137% as of December 31, 1998. We plan to continue improving our balance sheet in the years ahead.

Based on our view that natural gas will be in a tight supply/demand relationship in the U.S. during at least the next few years because of the significant structural challenges to growing gas supply and the growing demand for this clean-burning, domestically-produced fuel, we believe our focused natural gas acquisition, exploitation and exploration strategy should provide substantial value-creating growth opportunities in the years ahead. Our goal is to increase our overall production by 10% to 20% per year, with growth at an annual rate of 5% to 10% generated organically through the drillbit and the remaining growth generated through acquisitions. We have reached or exceeded this overall production goal in 11 of our 13 years as a public company.

Company Strengths

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

High-Quality Asset Base. Our producing properties are characterized by long-lived reserves, established production profiles and an emphasis on onshore natural gas. Based upon current production and proved reserve estimates, our proved reserves-to-production ratio, or reserve life, is approximately 14 years. In addition, we believe we are the sixth largest producer of natural gas in the U.S. (second among independents) and among the largest owners of proved U.S. natural gas reserves. In each of our operating areas, our properties are concentrated in locations that enable us to establish substantial economies of scale in drilling and production operations and facilitate the application of more effective reservoir management practices. We intend to continue building our asset base in each of our operating areas through a balance of acquisitions, exploitation and exploration. As of December 31, 2005, we operated properties accounting for approximately 80% of our daily production volumes. This large percentage of operated properties provides us with a high degree of operating flexibility and cost control.

Low-Cost Producer. Our high-quality asset base, the work ethic of our employees, our hands-on management style and our headquarters location in Oklahoma City have enabled us to achieve a low operating and administrative cost structure. During 2005, our operating costs per unit of production were $1.26 per mcfe, which consisted of general and administrative expenses of $0.14 per mcfe (including non-cash stock-based compensation of $0.03 per mcfe), production expenses of $0.68 per mcfe and production taxes of $0.44 per mcfe. We believe this is one of the lowest cost structures among publicly-traded, large-cap independent oil and natural gas producers.

Successful Acquisition Program. Our experienced acquisition team focuses on enhancing and expanding our existing assets in each of our operating areas. These areas are characterized by long-lived natural gas reserves, low lifting costs, multiple geological targets, favorable basis differentials to benchmark commodity prices, well-developed oil and gas transportation infrastructures and considerable potential for further consolidation of assets. Since 1998, we have completed $10.3 billion in acquisitions at an estimated average cost of $1.37 per mcfe of proved reserves. Included in this amount is $2.2 billion for unproved leasehold, but excluded from this amount is $809 million, or $0.14

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per mcfe of proved reserves, of deferred taxes established in connection with certain corporate acquisitions. We are well-positioned to continue making attractive acquisitions as a result of our extensive track record of identifying, completing and integrating multiple successful acquisitions, our large operating scale and our knowledge and experience in the regions in which we operate.

Large Inventory of Drilling Projects. During the 16 years since our inception, we have been among the five most active drillers of new wells in the United States. Presently, we are the most active driller in the U.S. (with 78 operated and 82 non-operated rigs drilling). Through this high level of activity over the years, we have developed an industry-leading expertise in drilling deep vertical and horizontal wells in search of large natural gas accumulations in challenging reservoir conditions. In addition, we believe that our large 11.6 million acre 3-D seismic inventory, much of which is proprietary to us, provides significant informational advantages over our competitors. As a result of our aggressive leasehold acquisition and seismic acquisition strategies, we have been able to accumulate a U.S. onshore leasehold position of approximately 8.5 million net acres and have acquired rights to 11.6 million acres of onshore 3-D seismic data to help evaluate our expansive acreage inventory. On this very large acreage position, our technical teams have identified approximately 28,000 exploratory and developmental drill sites, representing a backlog of more than ten years of future drilling opportunities at current drilling rates.

Hedging Program. We have used and intend to continue using hedging programs to reduce the risks inherent in acquiring and producing oil and natural gas reserves, commodities that are frequently characterized by significant price volatility. We believe this price volatility is likely to continue in the years ahead and that we can use this volatility to our benefit by taking advantage of prices when they reach levels that management believes are either unsustainable for the long-term or provide unusually high rates of return on our invested capital. Excluding hedges assumed in the acquisition of CNR, we currently have gas hedges in place covering 71% of our anticipated gas production for 2006, 36% of our anticipated gas production for 2007 and 22% of our anticipated gas production for 2008 at average NYMEX prices of $9.43, $9.85 and $9.10 per mcf, respectively (excluding collars and options). In addition, we have 63% of our anticipated oil production hedged for 2006, 22% of our anticipated oil production hedged for 2007 and 14% of our anticipated oil production hedged for 2008 at average NYMEX prices of $61.02, $62.42 and $65.48 per barrel of oil, respectively.

Entrepreneurial Management. Chesapeake was formed in 1989 with an initial capitalization of $50,000 and fewer than ten employees. Since then, management has guided the company through various operational and industry challenges and extremes of oil and gas prices to create the second largest independent U.S. producer of natural gas with approximately 2,900 employees and an enterprise value of approximately $20 billion. Our CEO and co-founder, Aubrey K. McClendon, has been in the oil and gas industry for 23 years and beneficially owns, as of March 10, 2006, approximately 22.4 million shares of our common stock.

Properties

Chesapeake focuses its natural gas exploration, development and acquisition efforts in one primary operating area and in four secondary operating areas: (i) the Mid-Continent (consisting of Oklahoma, Arkansas, southwestern Kansas and the Texas Panhandle), representing 51% of our proved reserves, (ii) the South Texas and Texas Gulf Coast region, representing 8% of our proved reserves, (iii) the Barnett Shale area of north-central Texas and the Ark-La-Tex area of central and East Texas and northern Louisiana, representing 14% of our proved reserves, (iv) the Permian Basin of western Texas and eastern New Mexico, representing 9% of our proved reserves, and (v) the Appalachian basin, principally in West Virginia, eastern Kentucky, eastern Ohio and southern New York, representing 17% of our proved reserves.

Chesapeake s strategy for 2006 is to continue developing our natural gas assets through exploratory and developmental drilling and by selectively acquiring strategic properties in the Mid-Continent and in our secondary areas. We project that our 2006 production will be between 576 bcfe and 586 bcfe. We have budgeted

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$3.0 to $3.2 billion for drilling, acreage acquisition, seismic and related capitalized internal costs, all of which is expected to be funded with operating cash flow based on our current assumptions. Our budget is frequently adjusted based on changes in oil and gas prices, drilling results, drilling costs and other factors. We expect to fund future acquisitions through a combination of operating cash flow, our revolving bank credit facility and, if needed, new debt and equity issuances.

Operating Areas

Mid-Continent. Chesapeake s Mid-Continent proved reserves of 3.798 tcfe represented 51% of our total proved reserves as of December 31, 2005, and this area produced 298 bcfe, or 64%, of our 2005 production. During 2005, we invested approximately $1.102 billion to drill 1,442 (498 net) wells in the Mid-Continent. We anticipate spending approximately 35% of our total budget for exploration and development activities in the Mid-Continent region during 2006.

South Texas and Texas Gulf Coast. Chesapeake s South Texas and Texas Gulf Coast proved reserves represented 622 bcfe, or 8%, of our total proved reserves as of December 31, 2005. During 2005, the South Texas and Texas Gulf Coast assets produced 64 bcfe, or 14%, of our total production. During 2005, we invested approximately $239.1 million to drill 115 (80 net) wells in the South Texas and Texas Gulf Coast region. We anticipate spending approximately 10% of our total budget for exploration and development activities in the South Texas and Texas Gulf Coast region during 2006.

Ark-La-Tex and Barnett Shale. Chesapeake s Ark-La-Tex and Barnett Shale proved reserves represented 1.069 tcfe, or 14%, of our total proved reserves as of December 31, 2005. During 2005, the Ark-La-Tex and Barnett Shale assets produced 58 bcfe, or 12%, of our total production. During 2005, we invested approximately $326.9 million to drill 257 (171 net) wells in the Ark-La-Tex and Barnett Shale regions. For 2006, we anticipate spending approximately 33% of our total budget for exploration and development activities in the Ark-La-Tex and Barnett Shale regions.

Permian Basin. Chesapeake s Permian Basin proved reserves represented 693 bcfe, or 9%, of our total proved reserves as of December 31, 2005. During 2005, the Permian assets produced 40 bcfe, or 9%, of our total production. During 2005, we invested approximately $265.9 million to drill 139 (56 net) wells in the Permian Basin. For 2006, we anticipate spending approximately 15% of our total budget for exploration and development activities in the Permian Basin.

Appalachian Basin. Chesapeake s Appalachian Basin proved reserves represented 1.296 tcfe, or 17%, of our total proved reserves as of December 31, 2005. During 2005, the Appalachian assets produced 6 bcfe, or 1%, of our total production, which was not acquired until November 14, 2005. During 2005, we invested approximately $8 million to drill 15 (11 net) wells in the Appalachian Basin. For 2006, we anticipate spending approximately 7% of our total budget for exploration and development activities in the Appalachian Basin.

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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.

	2005				2004				2003			
	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent
Development:												
Productive	1,736	97%	735	97%	1,239	97%	463	98%	958	96%	401	97%
Non-productive	51	3	21	3	34	3	9	2	37	4	11	3
Total	1,787	100%	756	100%	1,273	100%	472	100%	995	100%	412	100%
Exploratory:												
Productive	177	98%	57	95%	164	92%	67	91%	76	86%	36	83%
Non-productive	4	2	3	5	14	8	7	9	12	14	8	17
Total	181	100%	60	100%	178	100%	74	100%	88	100%	44	100%

The following table shows the wells we drilled by area:

	2005		2004		2003	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Mid-Continent	1,442	498	1,195	417	984	403
South Texas and Texas Gulf Coast	115	80	67	38	55	25
Ark-La-Tex and Barnett Shale	257	171	82	36		
Permian	139	56	107	55	44	28
Appalachia	15	11				
Total	1,968	816	1,451	546	1083	456

At December 31, 2005, we had 154 (67 net) wells in process. As of December 31, 2005, we owned 18 drilling rigs dedicated to drilling wells operated by Chesapeake. An additional 26 drilling rigs are under construction or on order, and we purchased 13 drilling rigs in February 2006. Our drilling business is conducted through our wholly owned subsidiary, Nomac Drilling Corporation.

Well Data

At December 31, 2005, we had interests in approximately 30,600 (16,985 net) producing wells, including properties in which we held an overriding royalty interest, of which 3,100 (1,360 net) were classified as primarily oil producing wells and 27,500 (15,625 net) were classified as primarily gas producing wells. Chesapeake operated approximately 18,200 of its 30,600 producing wells. During 2005, we drilled 902 (686 net) wells and participated in another 1,066 (130 net) wells operated by other companies. We operate approximately 80% 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 gas sales, average sales prices received and expenses for the periods indicated:

	2005	2004	2003
Net Production:			
Oil (mbbl)	7,698	6,764	4,665
Gas (mmcf)	422,389	322,009	240,366
Gas equivalent (mmcfe)	468,577	362,593	268,356
Oil and Gas Sales ($ in thousands):			
Oil sales	$ 401,845	$ 260,915	$ 132,630
Oil derivatives realized gains (losses)	(34,132)	(69,267)	(12,058)
Oil derivatives unrealized gains (losses)	4,374	3,454	(9,440)
Total oil sales	$ 372,087	$ 195,102	$ 111,132
Gas sales	$ 3,231,286	$ 1,789,275	$ 1,171,050
Gas derivatives realized gains (losses)	(367,551)	(85,634)	(5,331)
Gas derivatives unrealized gains (losses)	36,763	37,433	19,971
Total gas sales	$ 2,900,498	$ 1,741,074	$ 1,185,690
Total oil and gas sales	$ 3,272,585	$ 1,936,176	$ 1,296,822
Average Sales Price (excluding gains (losses) on derivatives):			
Oil ($ per bbl)	$ 52.20	$ 38.57	$ 28.43
Gas ($ per mcf)	$ 7.65	$ 5.56	$ 4.87
Gas equivalent ($ per mcfe)	$ 7.75	$ 5.65	$ 4.86
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Oil ($ per bbl)	$ 47.77	$ 28.33	$ 25.85
Gas ($ per mcf)	$ 6.78	$ 5.29	$ 4.85
Gas equivalent ($ per mcfe)	$ 6.90	$ 5.23	$ 4.79
Expenses ($ per mcfe):			
Production expenses	$ 0.68	$ 0.56	$ 0.51
Production taxes	$ 0.44	$ 0.29	$ 0.29
General and administrative expenses	$ 0.14	$ 0.10	$ 0.09
Oil and gas depreciation, depletion and amortization	$ 1.91	$ 1.61	$ 1.38
Depreciation and amortization of other assets	$ 0.11	$ 0.08	$ 0.06
Interest expense (a)	$ 0.47	$ 0.45	$ 0.55

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

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Oil and Gas Reserves

The tables below set forth information as of December 31, 2005 with respect to our estimated proved reserves, the associated estimated future net revenue and present value (discounted at 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 gas reserves we own.

	December 31, 2005		
	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)
Proved developed	76,238	4,442,270	4,899,694
Proved undeveloped	27,085	2,458,484	2,620,996
Total proved	103,323	6,900,754	7,520,690

	Proved Developed	Proved Undeveloped	Total Proved
		($ in thousands)	
Estimated future net revenue (a)	$ 32,435,228	$ 14,376,458	$ 46,811,686
Present value of future net revenue (a)	$ 16,271,138	$ 6,662,456	$ 22,933,594
Standardized measure (a) (b)			$ 15,967,911

	Oil (mbbl)	Gas (mmcf)	Gas Equivalent (mmcfe)	Percent of Proved Reserves	Present Value ($ in thousands)
Mid-Continent	48,915	3,504,653	3,798,216	51%	$ 11,308,766
South Texas and Texas Gulf Coast	3,308	602,551	622,399	8	2,459,379
Ark-La-Tex and Barnett Shale	6,379	1,030,962	1,069,236	14	3,551,565
Permian	39,126	457,811	692,570	9	2,040,175
Appalachia	1,094	1,289,919	1,296,482	17	3,462,744
Other	4,501	14,858	41,787	1	110,965
Total	103,323	6,900,754	7,520,690	100%	$ 22,933,594(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, 2005. The prices used in the external and internal reports yield weighted average wellhead prices of $56.41 per barrel of oil and $8.76 per mcf of gas. These prices should not be interpreted as a prediction of future prices. 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 future income tax expenses ($6.97 billion as of December 31, 2005).

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, 2005, our reserve estimates included 2.621 tcfe of reserves classified as proved undeveloped (PUD). Of this amount, approximately 56% (by volume) were initially classified as PUDs in 2005, 29% were initially classified as PUDs in 2004, 5% were initially classified as PUDs in 2003, and the remaining 10% were initially classified as PUDs prior to 2003. Of our proved developed reserves, 555 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 $14.4 billion at December 31, 2005, and the $6.7 billion present value thereof, has been calculated assuming that we will expend approximately $4.3 billion to develop these reserves. The amount and timing of these expenditures will depend on a number of factors, including actual drilling results, product prices and the availability of capital, but we have projected to incur $1.8 billion in 2006, $1.1 billion in 2007, $0.7 billion in 2008 and $0.7 billion in 2009 and beyond. We do not believe any of these proved undeveloped reserves are contingent upon installation of additional infrastructure and we are not subject to regulatory approval other than routine permits to drill, which we expect to obtain in the normal course of business.

Chesapeake employed third-party engineers to prepare independent reserve forecasts for approximately 78% of our proved reserves (by volume) at year-end 2005. These are not audits or reviews of internally prepared reserve reports. The estimates of the proved reserves evaluated by third-party engineers were within 99% of the company s own estimates and were used instead of our estimates for booking purposes. Netherland, Sewell & Associates, Inc. evaluated 25%, Data and Consulting Services, Division of Schlumberger Technology Corporation evaluated 16%, Lee Keeling and Associates, Inc. evaluated 15%, Ryder Scott Company L.P. evaluated 12%, LaRoche Petroleum Consultants, Ltd. evaluated 8%, and H. J. Gruy and Associates, Inc. evaluated 2% of our estimated proved reserves by volume at December 31, 2005. Of the 41,880 properties included in the 2005 reserve reports, the estimates prepared by the independent firms covered approximately 16,400 properties, or 39% of the total well count. Because, in management s opinion, it is cost prohibitive for third-party engineers to evaluate all of our wells, we have prepared reserve forecasts for approximately 22% 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.

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

Chesapeake s ownership interest used in calculating proved reserves and the associated estimated future net revenue was determined after giving effect to the assumed maximum participation by other parties to our farmout and participation agreements. The prices used in calculating the estimated future net revenue attributable to proved reserves do not reflect market prices for oil and gas production sold subsequent to December 31, 2005. There can be no assurance that all of the estimated proved reserves will be produced and sold at the assumed prices.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond Chesapeake s control. The reserve data represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates made by different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimates, and such revisions may be material. Accordingly, reserve estimates are often different from the actual quantities of oil and gas that are ultimately recovered. Furthermore, the estimated future net revenue from proved reserves and the associated present value are based upon certain assumptions, including prices, future production levels and costs that may not prove correct. 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

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in a change in the December 31, 2005 present value of estimated future net revenue of our proved reserves of approximately $315 million and $50 million, respectively. The estimated future net revenue used in this analysis does not include the effects of future income taxes or hedging. The foregoing uncertainties are particularly true as to proved undeveloped reserves, which are inherently less certain than proved developed reserves and which comprise a significant portion of our proved reserves.

The company s estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2005, 2004 and 2003, and the changes in quantities and standardized measure of such reserves for each of the three years then ended, are shown in Note 11 of the notes to the consolidated financial statements included in Item 8 of this report.

Development, Exploration, Acquisition and Divestiture Activities

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

		December 31,	
	2005	2004 ($ in thousands)	2003
Acquisition of properties:			
Proved properties	$ 3,554,651	$ 1,541,920	$ 1,110,077
Unproved properties	1,375,675	570,495	198,394
Deferred income taxes	251,722	463,949	(4,903)
Total	5,182,048	2,576,364	1,303,568
Development costs:			
Development drilling (a)	1,566,730	863,268	474,355
Leasehold acquisition costs	290,946	110,530	84,984
Asset retirement obligation and other (b)	52,619	41,924	54,657
Total	1,910,295	1,015,722	613,996
Exploration costs:			
Exploratory drilling	253,341	128,635	103,424
Geological and geophysical costs (c)	70,901	55,618	42,736
Total	324,242	184,253	146,160
Sales of oil and gas properties	(9,769)	(12,048)	(22,156)
Total	$ 7,406,816	$ 3,764,291	$ 2,041,568

(a) Includes capitalized internal cost of $94.1 million, $45.4 million and $30.9 million, respectively.
(b) The 2003 amount includes $24.1 million of asset retirement costs recorded as a result of implementation of SFAS 143 effective January 1, 2003.
(c) Includes capitalized internal cost of $8.1 million, $6.3 million and $4.6 million, respectively.

Our development costs included $671 million, $333 million and $229 million in 2005, 2004 and 2003, respectively, related to properties carried as proved undeveloped locations in the prior year s reserve reports. Included in our reserve report as of December 31, 2005 are estimated future development costs of $4.3 billion related to the development of proved undeveloped reserves ($1.8 billion in 2006, $1.1 billion in 2007, $0.7 billion in 2008 and $0.7 billion in 2009 and beyond). Chesapeake s developmental drilling schedules are subject to revision and reprioritization throughout the year, resulting from unknowable factors such as the relative success in an individual developmental drilling prospect leading to an additional drilling opportunity, rig availability, title issues or delays, and the effect that acquisitions may have on prioritizing development drilling plans.

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A summary of our development, exploration, acquisition and divestiture activities in 2005 by operating area is as follows:

	Gross Wells Drilled	Net Wells Drilled	Exploration and Development	Leasehold	Acquisition of Unproved Properties	Acquisition of Proved Properties (a)	Sales of Properties	Total
					($ in thousands)			
Mid-Continent	1,442	498	$ 1,102,099	$ 166,281	$ 178,169	$ 217,238	$ (214)	$ 1,663,573
South Texas and Texas Gulf Coast	115	80	239,107	87,418	224,947	215,166		766,638
Ark-La-Tex and Barnett Shale	257	171	359,206	7,816	350,416	666,309		1,383,747
Permian	139	56	233,597	29,452	114,874	339,838	(9,555)	708,206
Appalachia	15	11	7,673		506,881	2,367,835		2,882,389
Other			1,909	(21)	388	(13)		2,263
Total	1,968	816	$ 1,943,591	$ 290,946	$ 1,375,675	$ 3,806,373	$ (9,769)	$ 7,406,816

(a) Includes $252 million of deferred tax adjustments.

Acreage

The following table sets forth as of December 31, 2005 the gross and net acres of both developed and undeveloped oil and gas leases which we hold. Gross acres are the total number of acres in which we own a working interest. Net acres refer to gross acres multiplied by our fractional working interest. Acreage numbers do not include our options to acquire additional leasehold which have not been exercised.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	3,636,949	1,723,203	3,497,527	1,609,322	7,134,476	3,332,525
South Texas and Texas Gulf Coast	304,027	172,915	352,121	229,615	656,148	402,530
Ark-La-Tex and Barnett Shale	164,589	116,239	317,082	220,316	481,671	336,555
Permian	175,204	110,571	726,714	459,224	901,918	569,795
Appalachia	506,828	478,791	2,907,116	2,681,685	3,413,944	3,160,476
Canada			673,689	614,616	673,689	614,616
Other	43,424	18,607	95,240	76,084	138,664	94,691
Total	4,831,021	2,620,326	8,569,489	5,890,862	13,400,510	8,511,188

Marketing

Chesapeake s oil production is generally sold under market sensitive or spot price contracts. Our natural gas production is sold to purchasers under percentage-of-proceeds contracts, percentage-of-index contracts or spot price contracts. By the terms of the percentage-of-proceeds contracts, we receive a percentage of the resale price received by the purchaser for sales of residue gas and natural gas liquids recovered after transportation and processing of our gas. These purchasers sell the residue gas and natural gas liquids based primarily on spot market prices. The revenue we receive from the sale of natural gas liquids is included in oil sales. Under percentage-of-index contracts, the price per mmbtu we receive for our gas is tied to indexes published in *Inside FERC* or *Gas Daily*. Although exact percentages vary daily, as of February 2006, approximately 70% of our natural gas production was sold under short-term contracts at market-sensitive or spot prices.

During 2005, sales to Eagle Energy Partners I, L.P. (Eagle) of $851 million accounted for 18% of our total revenues. Chesapeake owns approximately 33% of Eagle. Management believes that the loss of this customer would not have a material adverse effect on our results of operations or our financial position. No other customer accounted for more than 10% of total revenues in 2005.

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

Drilling

In 2001, Chesapeake formed its 100% owned drilling rig subsidiary, Nomac Drilling Corporation (Nomac), with an investment of $26 million to build and refurbish five drilling rigs. As of December 31, 2005, Nomac owned 18 drilling rigs dedicated to drilling wells operated by Chesapeake and had an additional 26 rigs under construction or on order. The 18 drilling rigs which are currently drilling company-operated wells have depth ratings between 7,500 and 23,000 feet and range in drilling horsepower from 650 to 2,000. These drilling rigs are currently operating in the Mid-Continent region of Oklahoma and Texas. In February 2006, Nomac acquired 13 drilling rigs from privately-held Martex Drilling Corporation for $150 million. The acquisition of Martex will bring Nomac s rig fleet to 57 drilling rigs when all rigs on order are delivered. As the Martex drilling rigs currently under contract become available, they will be used for drilling company-operated wells.

Gas Gathering

Chesapeake owns and operates gathering systems in 13 states throughout the Mid-Continent and Appalachian regions. These systems are designed primarily to gather company production and are comprised of approximately 7,600 miles of gathering lines, treating facilities and processing facilities which provide service to approximately 8,775 wells.

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

Regulation of Oil and Gas Operations. Our exploration and production operations are subject to various types of regulation at the U.S. federal, state and local levels, although very few of our oil and gas leases are located on federal lands. Such regulation includes requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling and well operations. Other activities subject to regulation are:

- the location of wells,
- the method of drilling and completing wells,
- the surface use and restoration of properties upon which wells are drilled,
- the plugging and abandoning of wells,
- the disposal of fluids used or other wastes obtained in connection with operations,

- the marketing, transportation and reporting of production, and

- the valuation and payment of royalties.

Our operations are also subject to various conservation regulations. These include the regulation of the size of drilling and spacing units (regarding the density of wells which may be drilled in a particular area) and the

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

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. All of the company s sales of oil, natural gas liquids and natural gas are currently deregulated, 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 gas gathering will have a significantly adverse effect upon our capital expenditures, earnings or competitive position.

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

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

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

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

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

Income Taxes

Chesapeake recorded income tax expense of $545.1 million in 2005 compared to income tax expense of $289.8 million in 2004 and $191.8 million in 2003. Our effective income tax rate was 36.5% in 2005 compared to 36% in 2004 and 38% in 2003. The increase in 2005 reflected the impact state income taxes and permanent differences had on our overall effective rate. We expect our effective income tax rate will increase to 38% in 2006 to reflect our current assessment of expected increases in state income taxes and permanent differences.

At December 31, 2005, Chesapeake had federal income tax net operating loss (NOL) carryforwards of approximately $564.5 million. We also had approximately $169.6 million of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income and approximately $12.3 million of percentage depletion carryforwards. The NOL carryforwards expire from 2012 through 2025. The value of the remaining carryforwards depends on the ability of Chesapeake to generate taxable income. In addition, for AMT purposes, only 90% of AMT income in any given year may be offset by AMT NOLs.

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

In the event of an ownership change (as defined for income tax purposes), Section 382 of the Code imposes an annual limitation on the amount of a corporation s taxable income that can be offset by these carryforwards. The limitation is generally equal to the product of (i) the fair market value of the equity of the company multiplied by (ii) a percentage approximately equivalent to the yield on long-term tax exempt bonds during the month in which an ownership change occurs. In addition, the limitation is increased if there are recognized built-in gains during any post-change year, but only to the extent of any net unrealized built-in gains (as defined in the Code) inherent in the assets sold. Certain NOLs acquired through various acquisitions are also subject to limitations. The following table summarizes our net operating losses as of December 31, 2005 and any related limitations:

	Net Operating Losses		
	Total	Limited	Annual Limitation
		($ in thousands)	
Net operating loss	$ 564,451	$ 49,284	$ 27,754
AMT net operating loss	$ 169,635	$ 11,220	$ 6,652

Although no assurances can be made, we do not believe that an ownership change has occurred as of December 31, 2005. 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

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rules under Treasury regulations. If less than the full amount of the annual limitation is utilized in any given year, the unused por